TALLGRASS
ENERGY PARTNERS

2015 ANNUAL REPORT

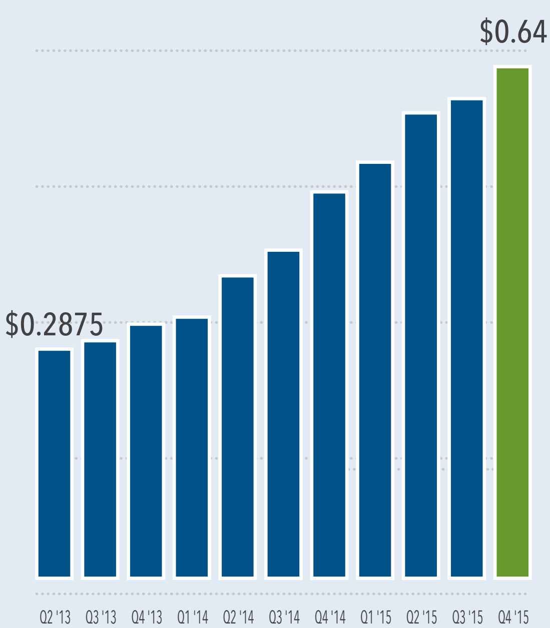




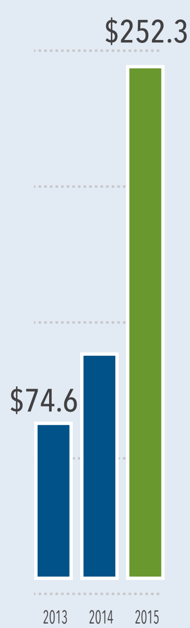


TALLGRASS
ENERGY PARTNERS

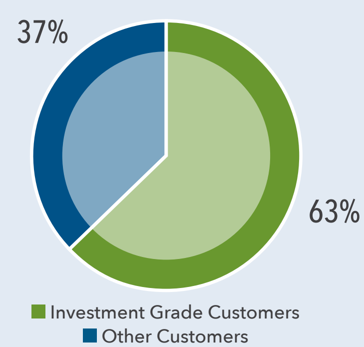
TEP Distributions
per Unit



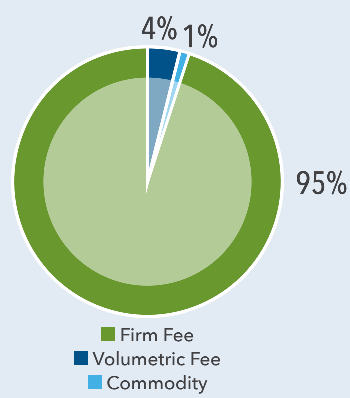
Adjusted EBITDA
(in millions)



TEP 2015 Investment
Grade Revenue



TEP 2015 Adjusted
EBITDA Contribution

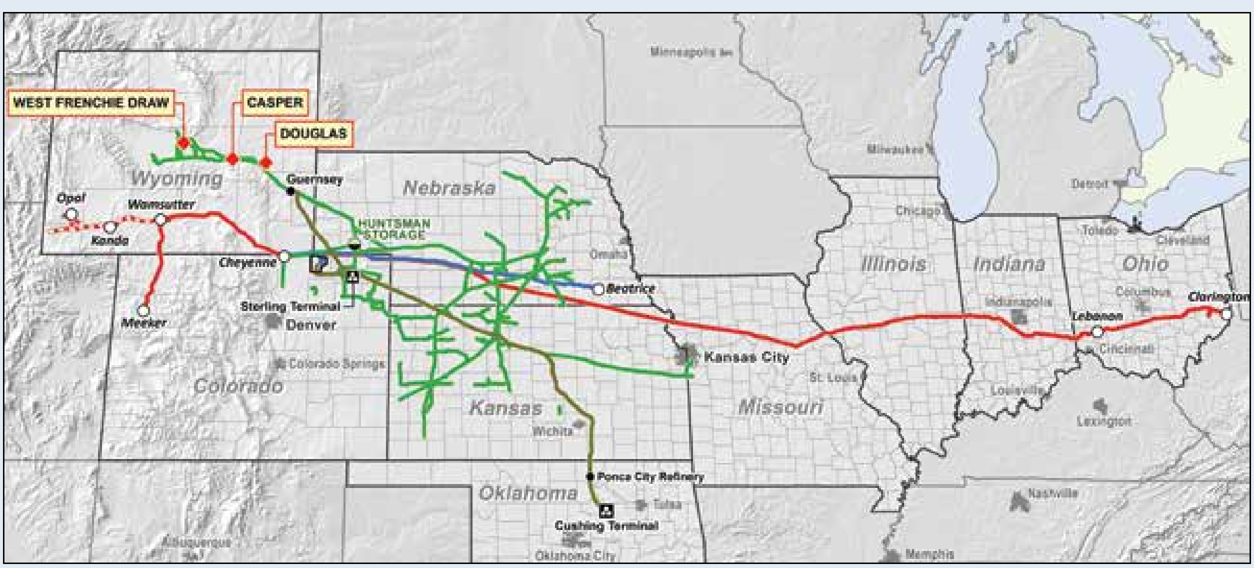


TALLGRASS
ENERGY PARTNERS

ABOUT TALLGRASS ENERGY PARTNERS, LP

Tallgrass Energy Partners, LP (NYSE: TEP) is a publicly traded, growth-oriented limited partnership formed to own, operate, acquire and develop midstream energy assets in North America. TEP currently provides crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through Pony Express, which owns the Pony Express System, a crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma that includes a lateral in northeast Colorado that commences in Weld County, Colorado, and interconnects with the pipeline just east of Sterling, Colorado. TEP provides natural gas transportation and storage services for customers in the Rocky Mountain and Midwest regions of the United States through the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system located in Colorado, Kansas, Missouri, Nebraska and Wyoming, and the Trailblazer Pipeline system, a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Nebraska. TEP provides services for customers in Wyoming at the Casper and Douglas natural gas processing facilities and the West Frenchie Draw natural gas treating facility, and NGL transportation services in Northeast Colorado. TEP also performs water business services in Colorado and Texas through BNN Water Solutions, LLC. TEP's operations are strategically located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg, Powder River, Wind River, Permian and Hugoton-Anadarko Basins and the Niobrara, Mississippi Lime, Eagle Ford and Bakken shale formations.

TALLGRASS SYSTEM MAP



Tallgrass Energy Partners

- Tallgrass Interstate Gas Transmission
- Trailblazer Pipeline
- Tallgrass Midstream
- Pony Express System
- NE Colorado Water & NGL Infrastructure

Tallgrass Development

- Rockies Express Pipeline
- Lease of Overthrust Pipeline Capacity
- Pony Express System
- Oil Storage Terminal

LETTER TO TEP UNITHOLDERS

A TRADITIONAL MIDSTREAM MLP—CHAPTER 3/YEAR 3

Every year I look forward to the privilege of sharing my thoughts with you in TEP's annual report. This year is no exception. While the header above is a repeat from last year, I believe it's an appropriate reminder of what Tallgrass is. We're a traditional midstream operator providing long-term, sustainable distribution growth to investors fueled by strong customer relationships, a significant geographic footprint and solid growth potential.

Last year I shared with you our belief that not all midstream assets are created equal. That belief is as strong as ever, even though current capital markets are treating MLPs the same and directly correlating them to crude oil prices. I believe that the capital markets will eventually get it right—that all MLPs are not alike. Nor are all midstream assets created equal. Here's why.

Today's MLP universe consists of approximately 130 energy MLPs. The public equity markets place many MLPs in a single basket and track them as an index. If you were to graph the performance of TEP against these indices over 2015—and in particular the last quarter of 2015—or against the price of crude oil over those same time frames, you might conclude that TEP is just like any other MLP or even a proxy for crude oil. As one of the principal architects of Tallgrass Energy, I firmly believe that conclusion is wrong. I encourage anyone with an interest in TEP to read my letter from last year's annual report in which I outline why our business model is one of the strongest in the industry. An important takeaway for this year is that **nothing fundamental to our business has changed in any material way.** In 2015 we accomplished many positive milestones, and the TEP value proposition is even more compelling today.

2015—ANOTHER YEAR OF "DOING WHAT WE SAID WE WERE GOING TO DO"

Our units recently hit a 52-week low of $25.82, down from an all-time high of $53.70 in Q1 of 2015. This represents a 52 percent decrease. I strongly believe that price action is not warranted based upon the strong fundamentals of our company.

On Feb. 12, 2016, TEP paid an annualized distribution of $2.56 per unit or $0.64 per quarter. A year ago we paid $1.94 per unit or $0.485 per quarter. This represents a 32 percent increase over the annualized distribution of a year ago.

While the two scenarios above are counterintuitive, they haven't shaken our confidence. We're confident in our future because our business plan hasn't changed—and it's working.

Our vision for the future is the same as it has been since inception. We continue to:

1) Manage our cost structure in a conservative, prudent manner;

2) Expand the services and capacities of our existing assets as needed by our customers and as demanded by the energy markets we serve;

3) Acquire additional assets in accretive "drop-down" transactions from Tallgrass Development (TDEV); and

4) Pursue additional midstream energy asset acquisition opportunities.

HOW WE EXECUTED LAST YEAR AND BEGAN 2016

For 2015, TEP generated cash available for distribution of more than 1.18 times our distributions based on TEP's common units outstanding on Dec. 31, 2015. A longer-term look at coverage shows that cumulatively TEP has generated approximately $46 million of excess distribution coverage since our IPO in May 2013. These two metrics are strong examples of how our business delivered excellent results with stable performance, and how we balanced delivery of best-in-class distribution growth with distribution safety.

In Q1 2015, we priced our second post-IPO primary offering of units, raising approximately $570 million of gross proceeds. Those proceeds, along with borrowings from our credit facility, were used in March 2015 to acquire another 33.3 percent interest in the Pony Express (Pony) crude oil pipeline for $700 million. This brought our interest in Pony to 66.7 percent. Looking back on our acquisitions of the first two-thirds of Pony, it's clear we made excellent buys. That's reflected in the 7.4x multiple of cash flow based on recent operating results at Pony.

Our third acquisition of Pony was subsequent to year-end 2015. On Jan. 1, 2016, we purchased an additional 31.3 percent of Pony, bringing our total ownership to 98 percent. We did this without accessing the public equity markets. Rather, we upsized our revolving credit facility to $1.5 billion and borrowed approximately $475 million. In addition, TDEV took back 6.518 million TEP common units valued at a price of $41.21. The transaction had a total value of about $744 million and again was acquired with a conservative expected cash flow multiple of 9.0x or less.

Pony became fully operational in the second quarter of 2015. We have five-year take-or-pay contracts (with about four years remaining) to move approximately 290,000 barrels of oil nearly 700 miles each day. The oil comes from the Bakken Shale in North Dakota and Montana, as well as from basins in Wyoming and Colorado, and is transported to Cushing, Oklahoma, and refinery points in Kansas. While those statistics alone make Pony a critical part of the country's crude oil infrastructure, Pony is capable of moving even greater volumes—as much as another 100,000 barrels per day. In fact, we recently averaged in excess of 325,000 barrels per day over the course of a month and transported nearly 340,000 barrels on a record day.

Importantly, Pony allows for the safe transportation of oil to trading markets with deep liquidity. In turn, this allows our customers to achieve better economics than if they were forced to sell the oil in North Dakota, Montana, Wyoming or Colorado by utilizing a more expensive, less reliable and more risky form of transportation such as tanker trucks or rail cars.

THE TALLGRASS PERSPECTIVE

The people who influenced me the most when I was growing up often said things like "actions speak louder than words;" "watch what they do, not what they say;" and "say what you do and do what you say." These words served as valuable advice to me then and underpin the Tallgrass values by which we strive to manage our business today.

With that in mind, here are some commitments we have made, where we stand now relative to those commitments and where we expect to go in the future:

- *Debt Levels: We have said we will have a long-term Debt/EBITDA Ratio of 3.0x to 4.0x. At year end we were at approximately 2.9x and post the January 2016 purchase of Pony we are at approximately 3.5x.*
- *Liquidity: We remain committed to having ample liquidity. After the closing of Pony in January 2016, we still have approximately $250 million of credit available on our revolving line of credit.*
- *Distributions and Coverage:* We consider our TEP MLP distributions sacred. ***I repeat:*** We consider our TEP MLP distributions sacred*. Our fellow unitholders own us principally for two core financial reasons: 1) the cash flow distribution (or dividend) that we pay and 2) the growth they hope to have in that distribution and the resulting growth in the value of their investment.*

We get it.

We are committed to paying a vast majority of our cash flow from operations as a distribution. We have pledged that when we generate additional sustainable operating cash, we will pay it out. We make payout decisions always with an eye toward maintaining that payout for the long haul. For the two-and-a-half-plus years we have been public, our coverage ratio has been between 1.14x and 1.22x. These ratios are higher than needed by a true midstream company such as TEP, particularly one of our size. We believe that in the long term, a large-pipe midstream company of our size can run at a 1.05x to 1.10x coverage ratio of DCF to Cash Distributions.

CLOSING THOUGHTS ON THE PAST, PRESENT AND FUTURE

From the inception of Tallgrass Energy more than three years ago, we have run our company for the long term—not for the 90-day reporting cycle. We have been successful in avoiding pitfalls others have fallen into, including high leverage, declining cash flows attributable to poor business risk-taking and capital requirements in excess of realistic expansion plans. In other words, we have worked hard to stay ahead of the curve.

I've navigated a lot of volatility in the 20 years that I've been involved in midstream energy and MLPs. I've seen crude oil at $8 a barrel in 1996. I was involved in purchasing an asset from an international oil company that wouldn't let the team selling their asset run a forward crude price curve at anything exceeding $20 a barrel. I've seen crude go up to $150 a barrel, back down to $30 a barrel, back up to $115 a barrel and then back down to $26 a barrel most recently. In that same period of time, however, global oil demand has grown from around 70 million barrels a day to about 95 million barrels a day. Similar volatility has existed in natural gas prices, and demand for natural gas also has grown globally and in the U.S. during that same timeframe.

I cite these statistics to remind you that we are *not* in the commodities business; rather, we are in the business of *transporting* commodities. Given this significant differentiator, Tallgrass Energy can accomplish its goals of steady stable cash distributions, reasonable growth and healthy financial metrics well into the future.

At Tallgrass, we don't obsess over short-term market movements. We focus on the things we can control and we manage our business for long-term success. Going forward, Tallgrass has the right assets, the right contracts with the right counterparties, the right balance sheet and ample liquidity to move our company forward and to meet our objectives and your expectations.

Once again, in 2015 Tallgrass Energy delivered. I hope that each and every owner of TEP will join me in sincerely thanking the Tallgrass employees for their continued outstanding effort. In addition to our employees, we again thank our supporters, our unitholders, our customers and our suppliers. All of you are our partners too. You all make our future possible, and you make our future bright.

On this date in 2016, we at TEP renew our commitment to you, our partners, to putting forth an outstanding effort to steward our existing business; to grow that business; to expand our services; and most importantly, to translate all of that into outstanding investment returns from TEP. We have closed Chapter 3, but we have only just begun a success story that will play out in many more chapters and years to come.

Sincere regards,

David G. Dehaemers, Jr.
President and Chief Executive Officer

SUMMARY FINANCIAL INFORMATION

(in thousands, except coverage and per unit data)	2015	2014	2013
Net income attributable to partners	$ 160,546	$ 70,681	$ 14,179
Add:			
Interest expense, net of noncontrolling interest	15,517	7,648	11,141
Depreciation and amortization expense, net of noncontrolling interest	75,529	45,389	29,549
Loss on extinguishment of debt	226	—	17,526
Non-cash (gain) loss related to derivative instruments	—	(184)	386
Non-cash compensation expense	5,103	5,136	1,798
Non-cash loss from asset sales	4,795	—	—
Distributions from unconsolidated investment	—	1,464	—
Less:			
Non-cash loss allocated to noncontrolling interest	(9,377)	(10,151)	—
Gain on remeasurement of unconsolidated investment	—	(9,388)	
Equity in earnings of unconsolidated investment	—	(717)	—
Adjusted EBITDA	$ 252,339	$109,878	$ 74,579
Add:			
Pony Express preferred distributions in excess of distributable cash flow attributable to Pony Express	$ —	$ 5,429	$ —
Pony Express deficiency payments	16,511	5,378	—
Less:			
Maintenance capital expenditures	(12,123)	(9,913)	(8,773)
Cash interest cost	(13,746)	(6,266)	(5,910)[a]
Distributions to noncontrolling interest	(22,479)	(5,361)	—
Distributable Cash Flow attributable to predecessor operations	—	(3,086)	—
Distributable cash flow (DCF)	220,502	96,059	59,896[a]
Less:			
Distributions	(192,580)	(83,329)	(49,140)[a]
DCF in excess of pro forma distributions	$ 27,922	$ 12,730	$ 10,756[a]
Distribution coverage	1.14x	1.15x	1.22x[a]
Distribution coverage, excluding amounts paid as a result of newly issued units[b]	1.18x	1.20x	

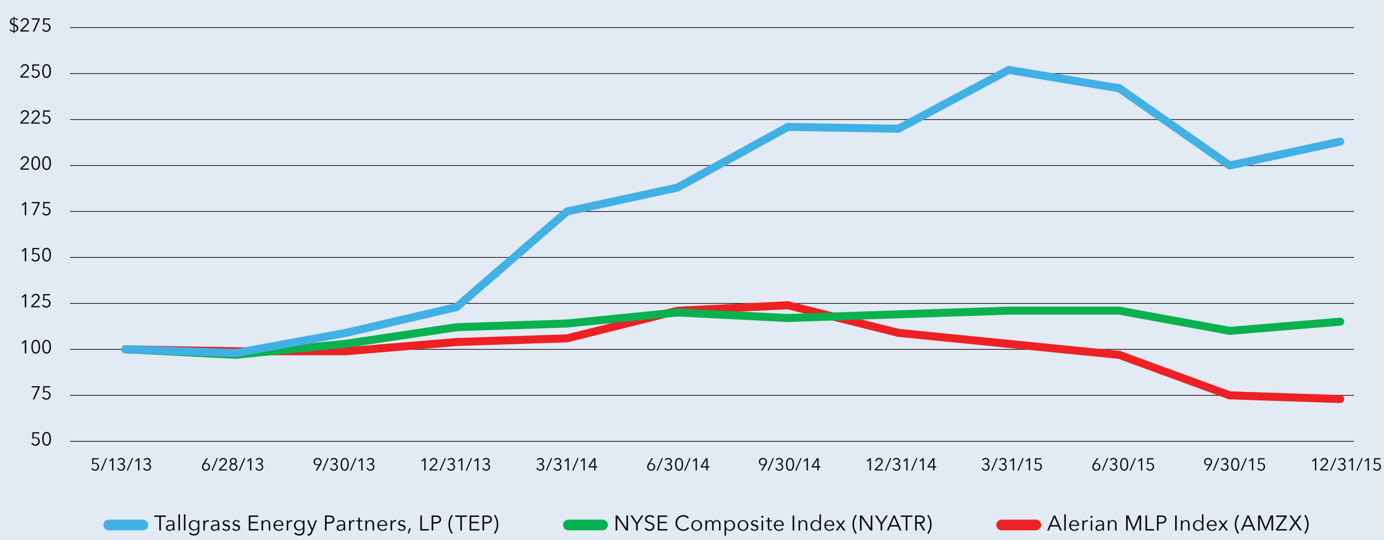
(a) Indicated amounts presented for the twelve months ended December 31, 2013 are on a pro forma basis, which assumes that our initial public offering and related formation transactions, including borrowings under our revolving credit facility, had closed on January 1, 2013. No cash distributions were paid with respect to the first quarter of 2013, and a prorated distribution of available cash was paid for the period from the closing of the IPO (May 17, 2013) through the end of the second quarter. Pro forma distributions were calculated using the minimum quarterly distribution for the first two quarters of 2013 and the increased distribution for the third and fourth quarters. Actual cash distributions for the twelve month period ending December 31, 2013, were $0.7547/unit. Pro forma interest expense (inclusive of commitment fees) for the twelve months ended December 31, 2013, was calculated by multiplying the actual cash interest cost for Q3 by three and adding the actual cash interest cost for Q4. Actual cash interest cost for the twelve month period ended December 31, 2013, was $3,555,000.

Management believes the pro forma presentation of distributable cash flow, distribution coverage and net income per limited partner unit provides investors with useful information to compare our historical financial results to future periods. These pro forma financial measures are presented for illustrative purposes only and are not necessarily indicative of the operating results or the financial position that would have been achieved had the initial public offering and related formation transactions been consummated on January 1, 2013 or of the results that may be obtained in the future.

(b) TEP paid $5,625,000 in February 2016 and $3,181,000 in August 2014 associated with units issued after the respective quarter-ends but prior to the record dates.

TOTAL UNITHOLDER RETURN

Tallgrass Energy Partners, LP



**For the purpose of distributions, funds are assumed to be reinvested in shares of the company at the closing price on the ex-dividend date.*


TALLGRASS
ENERGY PARTNERS
FORM 10-K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2015
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	**46-1972941**
(State or other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification Number)**
4200 W. 115th Street, Suite 350 **Leawood, Kansas**	**66211**
(Address of Principal Executive Offices)	**(Zip Code)**

(913) 928-6060
(Registrant's Telephone Number, Including Area Code)

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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

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

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

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 ☒ 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. ☐

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.

	Large accelerated filer	☒	Accelerated filer	☐
(Check one):	Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

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

The aggregate market value of voting and non-voting common equity held by non-affiliates on June 30, 2015, the last business day of the Registrant's most recently completed second fiscal quarter (based on the closing sale price of $48.08 of the Registrant's Common Units, as reported by the New York Stock Exchange on such date) was approximately $1,622.7 million.

On February 17, 2016, the Registrant had 67,162,232 Common Units and 834,391 General Partner Units outstanding.

TALLGRASS ENERGY PARTNERS, LP
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Glossary of Common Industry and Measurement Terms

Bakken oil production area: Montana and North Dakota in the United States and Saskatchewan and Manitoba in Canada.

Barrel (or bbl): forty two U.S. gallons.

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.

Commodity sensitive contracts or arrangements: contracts or other arrangements, including tariff provisions, that directly expose our cash flows to increases and decreases in the price of commodities such as crude oil, natural gas and NGLs. Examples are Keep Whole Processing Contracts and Percent of Proceeds Processing Contracts, as well as pipeline loss allowances on our pipelines.

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

Contract barrels: barrels of crude oil that our customers have contractually agreed to ship in exchange for firm service assurance of capacity and deliverability to delivery points.

Delivery point: any point at which product in a pipeline is delivered to or for the account of a customer.

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.

EPA: the United States Environmental Protection Agency.

FERC: Federal Energy Regulatory Commission.

Firm fee contracts: firm fee contracts generally obligate our customers to pay a fixed recurring charge to reserve an agreed upon amount of capacity and/or deliverability on our assets, regardless if the contracted capacity is actually used by the customer. Such contracts are also commonly known as "take-or-pay" contracts.

Firm services: services pursuant to which customers receive firm assurances regarding the availability of capacity and/or deliverability of natural gas, crude oil or other hydrocarbons or water on our assets up to a contracted amount.

Fractionation: the process by which NGLs are further separated into individual, typically more valuable components including ethane, propane, butane, isobutane and natural gasoline.

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.

Interruptible services: services pursuant to which customers receive limited, or no, assurances regarding the availability of capacity and deliverability in our assets.

Keep Whole Processing Contracts: natural gas processing contracts in which we are required to replace the Btu content of the NGLs extracted from inlet wet gas processed with purchased dry natural gas.

Line fill: the volume of oil, in barrels, in the pipeline from the origin to the destination.

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.

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

Long-term: with respect to any contract, a contract with an initial duration greater than one year.

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).

Natural Gas Processing: the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream.

Non-contract barrels (or walk-up barrels): barrels of crude oil that our customers ship based solely on availability of capacity and deliverability with no assurance of future capacity.

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.

Percent of Proceeds Processing Contracts: natural gas processing contracts 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 percent of proceeds contracts may also require our customers to pay a monthly reservation fee for processing capacity.

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.

Produced water: all water removed from a well as a byproduct of the production of hydrocarbons and water removed from a well in connection with operations being conducted on the well, including naturally occurring water in the recovery formation, flow back water recovered during completion and fracturing operations and water entering the recovery formation through water flooding techniques.

Receipt point: the point where a product is received by or into a gathering system, processing facility, or transportation pipeline.

Reservoir: a porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (such as 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 transportation to end-user markets.

TBtu: one trillion British Thermal Units.

Tcf: one trillion cubic feet.

Throughput: the volume of products, such as crude oil, natural gas or water, transported or passing through a pipeline, plant, terminal or other facility during a particular period.

Uncommitted shippers (or walk-up shippers): customers that have not signed long-term shipper contracts and have rights under the FERC tariff as to rates and capacity allocation that are different than long-term committed shippers.

Volumetric fee contracts: volumetric fee contracts generally obligate a customer to pay fees based upon the extent to which such customer utilizes our assets for midstream energy services. Unlike firm fee contracts, under volumetric fee contracts our customers are not generally required to pay a charge to reserve an agreed upon amount of capacity and/or deliverability.

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 storage 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 base 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.

PART I

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 terms our "general partner" or "TEP GP" refer 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, as the context may require, other entities under its control, and references to "EMG" are to The Energy & Minerals Group, its affiliated investment funds and, as the context may require, 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," "plan," "estimate," "anticipate," "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 Tallgrass Development's infrastructure programs, revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this 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:

- our ability to complete and integrate acquisitions from Tallgrass Development or from third parties, including our acquisition of water business assets in Weld County, Colorado that was completed in December 2015 and our purchase of an additional 31.3% interest in Tallgrass Pony Express Pipeline, LLC ("Pony Express") that was completed in January 2016;
- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by third-party operators, processors and transporters;
- the demand for our services, including crude oil transportation services, natural gas transportation, storage and processing services and water business 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 level of production of crude oil, natural gas and other hydrocarbons and the resultant market prices of crude oil, natural gas, NGLs, and other hydrocarbons;
- the availability and price of natural gas and crude oil, and fuels derived from both, 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 crude oil, transporting, storing and processing natural gas, and transporting, gathering and disposing of water produced in connection with hydrocarbon exploration and production activities;

- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- large or multiple customer defaults;
- 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

Overview

We are a publicly traded, growth-oriented limited partnership formed in 2013 to own, operate, acquire and develop midstream energy assets in North America. We currently provide crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through Pony Express, which owns a crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma that includes a lateral in Northeast Colorado that commences in Weld County, Colorado, and interconnects with the pipeline just east of Sterling, Colorado (the "Pony Express System"). We provide natural gas transportation and storage services for customers in the Rocky Mountain and Midwest regions of the United States through the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system located in Colorado, Kansas, Missouri, Nebraska and Wyoming (the "TIGT System"), and a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Nebraska (the "Trailblazer Pipeline"). We also provide services for customers in Wyoming at the Casper and Douglas natural gas processing facilities and the West Frenchie Draw natural gas treating facility (collectively, the "Midstream Facilities"), and NGL transportation services in Northeast Colorado. We perform water business services in Colorado and Texas through BNN Water Solutions, LLC ("Water Solutions"). Our operations are strategically located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg, Powder River, Wind River, Permian and Hugoton-Anadarko Basins and the Niobrara, Mississippi Lime, Eagle Ford and Bakken shale formations.

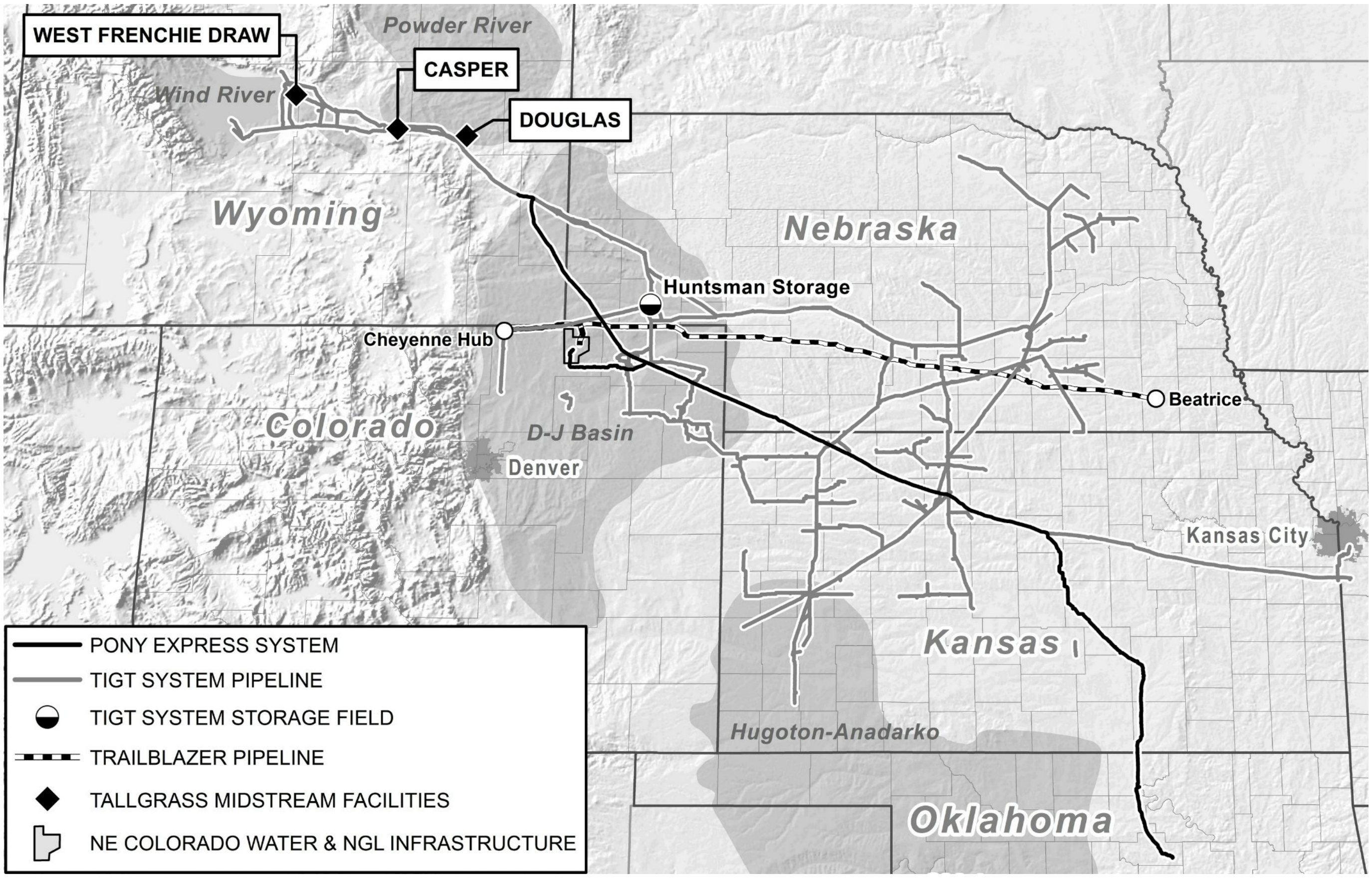
We intend to continue to leverage our relationship with Tallgrass Development and utilize the significant experience of our management team to execute our growth strategy of acquiring midstream assets from Tallgrass Development and third parties, increasing utilization of our existing assets and expanding our systems through construction of additional assets. Our reportable business segments are:

- Crude Oil Transportation & Logistics—the ownership and operation of a crude oil pipeline system;
- Natural Gas Transportation & Logistics—the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities; and
- Processing & Logistics—the ownership and operation of natural gas processing, treating and fractionation facilities, the provision of water business services primarily to the oil and gas exploration and production industry and the transportation of NGLs.

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.

Our Assets

Our assets primarily consist of the Pony Express System, the TIGT System, the Trailblazer Pipeline, the Midstream Facilities, and Water Solutions, each of which is described in more detail below. The following map shows the Pony Express System, the TIGT System, the Trailblazer Pipeline, the Midstream Facilities, and our Northeast Colorado and NGL infrastructure, which includes our NGL transportation line and Water Solutions' freshwater delivery and storage and produced water gathering and disposal systems.



Crude Oil Transportation & Logistics Segment

Pony Express. The Pony Express System is an approximately 764-mile crude oil pipeline commencing in Guernsey, Wyoming, and terminating in Cushing, Oklahoma, with delivery points at the Ponca City Refinery and in Cushing, Oklahoma. It includes a lateral in Northeast Colorado that commences in Weld County, Colorado, and interconnects with the pipeline just east of Sterling, Colorado. As of December 31, 2015, we owned a 66.7% membership interest in Pony Express, but effective January 1, 2016, we acquired an additional 31.3% membership interest, bringing our total membership interest in Pony Express to 98.0%. For the year ended December 31, 2015, Continental Resources and Shell Trading (US) Company ("Shell") accounted for approximately 28% and 19% of our segment revenue in the Crude Oil Transportation & Logistics segment, respectively, and approximately 16% and 15% of our revenues on a consolidated basis, respectively.

The table below sets forth certain information regarding our Crude Oil Transportation & Logistics segment as of December 31, 2015 and for the three months ended December 31, 2015:

Approximate Design Capacity (bbls/d) [1]	Approximate Contractible Capacity Under Contract [2]	Weighted Average Remaining Firm Contract Life [3]	Approximate Average Daily Throughput (bbls/d) [4]
320,000	100%	4 years	288,362

(1) Excludes additional capacity related to the Pony Express System's ability to inject drag reducing agent, which is an additive that increases pipeline flow efficiency.

(2) We are required to make no less than 10% of design capacity available for non-contract, or "walk-up", shippers. Approximately 100% of the remaining design capacity (or available contractible capacity) is committed under contract.

(3) Based on the average annual reservation capacity for each such contract's remaining life.

(4) Approximate average daily throughput for the year ended December 31, 2015 was 236,256 bbls/d and is reflective of the volumetric ramp-up during the year due to the construction and expansion efforts of the Pony Express lateral in Northeast Colorado and third-party pipelines with which Pony Express shares joint tariffs.

Natural Gas Transportation & Logistics Segment

TIGT System. The TIGT System is a FERC-regulated natural gas transportation and storage system with approximately 4,655 miles of varying diameter transportation pipelines serving Wyoming, Colorado, Kansas, Missouri and Nebraska. The TIGT System includes the Huntsman natural gas storage facility located in Cheyenne County, Nebraska. 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 year ended December 31, 2015, approximately 87% of the TIGT System's transportation revenue was generated from contracts with on-system customers.

Trailblazer Pipeline. The Trailblazer Pipeline is a FERC-regulated natural gas pipeline system with approximately 454 miles of transportation pipelines that begins along the border of Wyoming and Colorado and extends to Beatrice, Nebraska. Substantially all of Trailblazer Pipeline's currently available design capacity of approximately 902 MMcf/d is subscribed for under firm transportation contracts.

The following tables provide information regarding our Natural Gas Transportation & Logistics segment assets as of December 31, 2015 and for the years ended December 31, 2015, 2014, and 2013:

	Approximate Average Daily Throughput (MMcf/d) Year Ended December 31,		
	2015	2014	2013
Transportation	1,129	955	991

	Approximate Number of Miles	Approximate Capacity	Total Firm Contracted Capacity (1)	Approximate % of Capacity Subscribed under Firm Contracts	Weighted Average Remaining Firm Contract Life (2)
Transportation	5,109	1,982 MMcf/d	1,428 MMcf/d	72%	2 years
Storage	n/a	15.974 Bcf (3)	11 Bcf	69%	6 years

(1) Reflects total capacity reserved under long-term firm fee contracts, including backhaul service, as of December 31, 2015.

(2) Weighted by contracted capacity as of December 31, 2015.

(3) The FERC certificated working gas storage capacity.

Processing & Logistics Segment

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. The Casper and Douglas plants currently have combined processing capacity of approximately 190 MMcf/d. The Casper plant also has a NGL fractionator with a capacity of approximately 3,500 barrels per day. 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. In the fourth quarter of 2015, we completed construction and commenced commercial service on a new NGL pipeline with an approximate capacity of 19,500 barrels per day that transports NGLs from a processing plant in Northeast Colorado to an interconnect with Overland Pass Pipeline. As of December 31, 2015, approximately 92% of our reserved processing capacity was subject to firm or volumetric fee contracts, with the majority of fee revenue based on the volumes actually processed. The remaining 8% was subject to commodity sensitive contracts. Our NGL pipeline in Northeast Colorado is supported by a 10-year lease for 100% of the pipeline capacity.

The table below sets forth certain information regarding the Midstream Facilities in our Processing & Logistics segment as of December 31, 2015 and for the years ended December 31, 2015, 2014, and 2013:

Approximate Plant Capacity (MMcf/d) [(1)]	Approximate Capacity Under Contract	Weighted Average Remaining Contract Life [(2)]	Approximate Average Inlet Volumes (MMcf/d) Year Ended December 31,		
			2015	2014	2013
190	89%	3 years	122	152	133

(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.

Water Solutions. We provide water business services through our approximate 92% membership interest in Water Solutions. Water Solutions owns and operates a freshwater delivery and storage system and a produced water gathering and disposal system in Weld County, Colorado. This system is used to support third party exploration, development, and production of oil and natural gas. Water Solutions also sources treated wastewater from municipalities in Texas and recycles flowback water and other water produced in association with the production of oil and gas in Colorado.

The table below sets forth certain information regarding the Water Solutions assets in our Processing & Logistics segment as of December 31, 2015 and for the years ended December 31, 2015, 2014, and 2013:

	Approximate Capacity Under Contract	Approximate Current Design Capacity (bbls/d)	Remaining Contract Life	Approximate Average Volumes (bbls/d) Year Ended December 31,		
				2015	2014	2013
Freshwater.........................	56%	30,863 [(1)]	5 years	14,579	16,433	—
Gathering and Disposal......	80%	35,000 [(2)]	9 years	7,951 [(2)]	—	—

(1) Represents the average daily fresh water supply for the BNN Redtail, LLC fresh water pipeline acquired in 2014 and the BNN Western, LLC ("Western") fresh water delivery and storage system in Weld County, Colorado acquired in December 2015 as discussed under *"Acquisitions"* below.

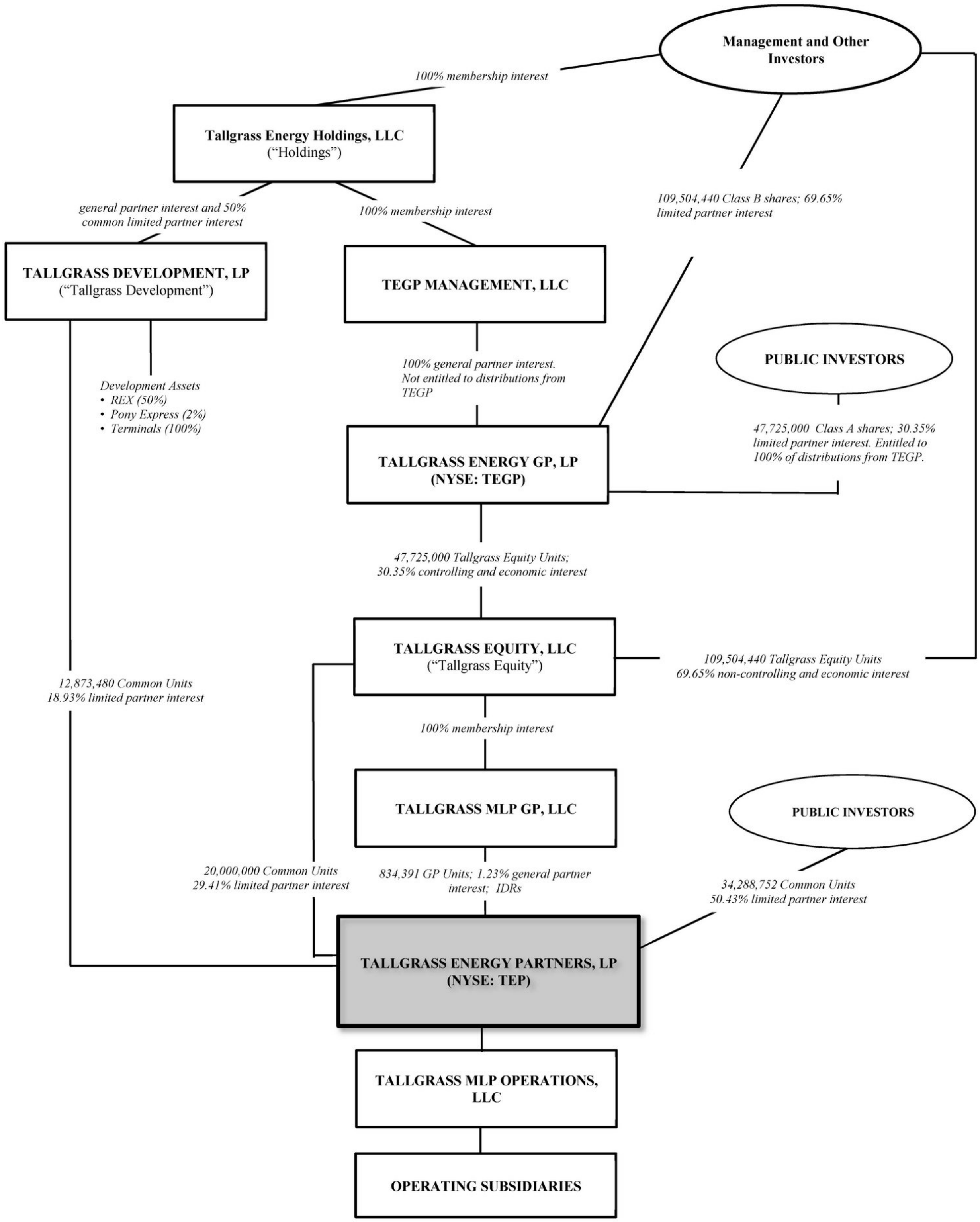
(2) Represents the daily disposal well injection capacity and the average daily disposal injection volumes, respectively, for the Western produced water gathering and disposal system in Weld County, Colorado acquired in December 2015 as discussed under *"Acquisitions"* below.

Organizational Structure

Our general partner interest and all of our incentive distribution rights ("IDRs"), are held by our general partner, whose sole member is Tallgrass Equity, LLC ("Tallgrass Equity"). Tallgrass Equity also directly owns 20 million TEP common units. Tallgrass Energy GP, LP ("TEGP"), a Delaware limited partnership that completed its initial public offering in May 2015 and has elected to be treated as a corporation for U.S. federal income tax purposes, owns a 30.35% membership interest in, and is the managing member of, Tallgrass Equity. TEGP Management, LLC, a Delaware limited liability company ("TEGP Management"), is TEGP's general partner. Tallgrass Energy Holdings, LLC, a Delaware limited liability company ("Tallgrass Energy Holdings"), is the sole member of TEGP Management. Tallgrass Energy Holdings is also the general partner of Tallgrass Development.

Our operations are conducted directly and indirectly through, and our operating assets are owned by, our subsidiaries. Our general partner is responsible for conducting our business and managing our operations. However, Tallgrass Energy Holdings effectively controls our business and affairs through the exercise of its rights as the party that controls the sole member of our general partner, including its right to appoint members to the board of directors of our general partner.

The chart below shows the structure of Tallgrass Energy Holdings and its subsidiaries as of February 17, 2016 in a summary format.



Tallgrass Development

Tallgrass Development owns 12,873,480 of our common units, representing approximately 18.9% of our outstanding equity at February 17, 2016. Tallgrass Development is controlled by its general partner, Tallgrass Energy Holdings, which also indirectly controls our general partner. In connection with our initial public offering on May 17, 2013 (the "IPO"), Tallgrass Development contributed to us 100% of the membership interest in Tallgrass Interstate Gas Transmission, LLC ("TIGT"), which owns and operates the TIGT System, and 100% of the membership interest in Tallgrass Midstream, LLC ("TMID"), which owns and operates the Midstream Facilities. Since then, we have acquired the following additional assets from Tallgrass Development: (1) in April 2014, a 100% membership interest in Trailblazer Pipeline Company LLC ("Trailblazer"), which owns and operates the Trailblazer Pipeline, and (2) in three separate transactions, the most recent of which was effective on January 1, 2016, a 98.0% membership interest in Pony Express, which owns and operates the Pony Express System. Tallgrass Development continues to own and manage a portfolio of midstream assets, including the following:

- a 50% interest in, and operation of, the Rockies Express Pipeline, or REX Pipeline, an approximately 1,713 mile natural gas pipeline with a bi-directional design capacity of up to 1.8 Bcf/d, that extends from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio; and
- Tallgrass Terminals, LLC, or Terminals, which holds a 20% membership interest in Deeprock Development, LLC (the owner of a crude oil terminal in Cushing, Oklahoma with approximately 2.3 million bbls of storage capacity), and a crude oil terminal in Sterling, Colorado with approximately 1.3 million bbls of storage capacity.

Pursuant to an Omnibus Agreement entered into upon the closing of our IPO, among us, TEP GP, Tallgrass Development and Tallgrass Energy Holdings (the "TEP Omnibus Agreement"), Tallgrass Development granted us a right of first offer to acquire certain assets held by Tallgrass Development at the time of our IPO, which we refer to as the Retained Assets, if Tallgrass Development decides to sell such assets. The Retained Assets include Tallgrass Development's interest in Rockies Express Pipeline LLC and Tallgrass Development's remaining noncontrolling interest in Pony Express. Terminals is not a Retained Asset. Tallgrass Development 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 Tallgrass Development or pursue any such joint acquisitions. However, given the significant economic interest in us held by Tallgrass Development and its affiliates, including Tallgrass Energy Holdings, we believe Tallgrass Development will be incentivized to offer us the opportunity to acquire the Retained Assets and Terminals as each continues maturing into an operating profile 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.

Acquisitions

The acquisition of midstream assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objectives. Such assets and businesses include crude oil and NGL logistics assets, natural gas transportation and storage assets and other energy assets that have characteristics and provide opportunities similar to our existing business lines and enable us to leverage our assets, knowledge and skill sets. Below are summaries of significant acquisitions we completed in 2015. See Note 4 – *Acquisitions* to our Consolidated Financial Statements in Item 8.—Financial Statements and Supplementary Data for a full discussion regarding our acquisition activities.

- *Pony Express System*. Effective March 1, 2015, we acquired an additional 33.3% membership interest in Pony Express for cash consideration of approximately $700 million, bringing our total ownership in Pony Express to 66.7% on such date. Effective January 1, 2016, we acquired an additional 31.3% membership interest in exchange for cash consideration of $475 million and the issuance of 6,518,000 of our common units, bringing our total ownership interest in Pony Express to 98.0%.
- *Weld County, Colorado Water Assets*. On December 16, 2015, we acquired the following assets located in Weld County, Colorado from Whiting Oil and Gas Corporation ("Whiting") in exchange for total cash consideration of $75 million: a fresh water delivery system and a produced water gathering and disposal system, seven fresh water ponds with approximately 2.4 million barrels of storage and three produced water disposal wells, along with long-term firm fee contracts and acreage dedications from Whiting.

Competition

All of our businesses face strong competition for acquisitions and development of new projects from both established and start-up companies. Competition may increase the cost to acquire existing facilities or businesses and may result in fewer commitments and lower returns for new pipelines or other development projects. Our competitors may have greater financial resources than we possess or may be willing to accept lower returns or greater risks. Competition differs by region and by the nature of the business or the project involved.

Pony Express encounters competition in the crude oil transportation business. A number of pipeline companies compete with Pony Express to service takeaway volumes in markets that Pony Express currently serves, including pipelines owned and operated by Spectra Energy, Plains All American, Suncor, SemGroup, Magellan Midstream Partners, Anadarko, Noble, NGL Energy Partners, Energy Transfer Partners, and Enbridge Energy Partners. Pony Express also competes with rail facilities, which can provide more delivery optionality to crude oil producers and marketers looking to capitalize on basis differentials between two primary crude oil price benchmarks (West Texas Intermediate Crude and Brent Crude), and with refineries that source barrels in areas served by Pony Express.

Our principal competitors in our natural gas transportation and storage business 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, Northern Natural Gas Company, and Southern Star Central Gas Pipeline, Inc., some of whom also have existing storage facilities connected to their transportation systems that compete with our storage facilities. In addition to this competition, which is primarily comprised of other pipeline companies that transport gas out of the Rocky Mountain region, Trailblazer also delivers gas into a very competitive marketplace that receives gas from the developing shale plays like the Bakken, Marcellus and Utica. As these supplies increase, it reduces the need for traditional Rockies gas production that is accessible from Trailblazer.

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, Inc., which we refer to as Kinder Morgan, ONEOK Partners, LP, Western Gas Partners, LP, Williams Partners L.P. and Meritage Midstream Services II, LLC. In addition, due to the competitive 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.

Further, we experience competition in the water business services. Our principal competitors in such business are transactional water service companies and larger produced water disposal well owners. An example of a competitor that is a transactional water service company would be Select Energy Services, as they provide temporary fresh water supply and water recycling that competes with Water Solutions. An example of a competitor that is a larger disposal well owner would be NGL Energy Partners, as they compete with Water Solutions through produced water gathering and disposal in areas of concentrated production activity.

Additionally, pending and future construction projects, if and when brought online, may also compete with our crude oil transportation, natural gas transportation and storage, water transportation, gathering and disposal, and processing services. Further, as a provider of midstream services to the natural gas and crude oil industries, 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 and crude oil, including price changes, the availability of natural gas and crude oil and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, weather, and the ability to convert to alternative fuels.

Regulatory Environment

Federal Energy Regulatory Commission

We provide open-access interstate transportation service on our natural gas transportation systems pursuant to tariffs approved by the FERC. As interstate transportation and storage systems, the rates, terms of service and continued operations of the TIGT System and the Trailblazer Pipeline 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 EPAct 2005. The rates and terms of service on the Pony Express System are subject to regulation by the FERC under the Interstate Commerce Act, or the ICA, and the Energy Policy Act of 1992. We provide interstate transportation service on the Pony Express System pursuant to tariffs on file with the FERC. Our NGL pipeline is leased to a third party who has obtained a temporary waiver for itself from the FERC from the tariff, filing and reporting requirements of the ICA.

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 FERC's authority over crude oil pipelines is less broad than its authority over interstate natural gas pipelines and includes rates, rules and regulations for service, the form of tariffs governing service, the maintenance of accounts and records, and depreciation and amortization policies.

The rates and terms for access to natural gas pipeline transportation services are subject to extensive regulation and 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 natural gas pipelines provide firm and interruptible transportation service on an open access basis, 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 interstate natural gas pipelines' historical role of providing bundled sales service of natural gas and to require pipelines to offer unbundled storage and transportation services on a not unduly discriminatory or preferential 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 negotiated rates as an alternative to cost-based rates 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 the transmission function personnel of interstate natural gas pipelines operate independently of the marketing function personnel of the pipeline or its affiliates.

TIGT 2015 Cost and Revenue Study

On October 3, 2015, TIGT submitted a cost and revenue study in compliance with Article IV of the Stipulation and Agreement of Settlement filed on May 5, 2011 in FERC Docket No. RP11-1494 ("2011 Settlement") and approved by the FERC on September 22, 2011. The cost and revenue study demonstrates that TIGT is under-recovering its cost of service. Consistent with the 2011 Settlement, the study was based on the unadjusted actual costs, revenues and volumes for a 12-month base period ended June 30, 2015, in compliance with Section 154.303(a)(1) of the FERC's regulations. The cost and revenue study did not propose any change to TIGT's currently effective rates. The cost and revenue study was accepted by FERC on February 1, 2016 in compliance with the 2011 Settlement.

TIGT 2015 General Rate Case Filing

On October 30, 2015, TIGT filed a general rate case with the FERC pursuant to Section 4 of the NGA. The rate case proposed a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by TIGT. In addition, TIGT proposed certain changes to the transportation rate design of its system to replace the current rate zone structure with a single "postage stamp" rate. TIGT also proposed new incremental charges, including (i) a charge for deliveries made to points without certain electronic flow measurement equipment, and (ii) a Cost Recovery Mechanism ("CRM") charge to completely or partially reimburse TIGT for certain expenses and costs it incurs to comply with anticipated new PHMSA and EPA regulations. TIGT also proposed to replace its fixed fuel and lost and unaccounted for ("FL&U") charge with a FL&U tracker that would compensate TIGT for its actual FL&U expenses and adjust each year to reflect the previous period's under/over collection and the forecasted FL&U expense for the upcoming period. TIGT also proposed to implement a power cost tracker to recover the actual power costs incurred by TIGT to power its compressors. Finally, TIGT proposed certain revisions to its FERC Gas Tariff addressing a number of other rate and non-rate matters. Under the NGA and the FERC's regulations, TIGT's shippers and other interested parties, including the FERC's Trial Staff, have a right to challenge any aspect of TIGT's rate case filing. Accordingly, numerous TIGT customers have protested aspects of TIGT's NGA Section 4 rate filing.

On November 30, 2015, the FERC issued an order accepting and suspending the proposed rates and a majority of the proposed tariff records to be effective upon motion May 1, 2016, subject to refund, certain modifications to TIGT's proposed CRM charge, and the outcome of an evidentiary hearing before a FERC Administrative Law Judge (the "Suspension Order"). In the Suspension Order, the FERC also accepted two tariff records related to *force majeure* events and reservation charge crediting to be effective December 1, 2015, subject to certain modifications. On December 21, 2015, TIGT made a compliance filing with the FERC to modify TIGT's proposed CRM charge and update the tariff records related to *force majeure* events and reservation charge crediting as directed by the FERC in the Suspension Order. No comments or protests were filed in response to the compliance filing and FERC accepted the compliance filing on February 1, 2016. One request for rehearing of the Suspension Order is currently pending before the FERC with respect to the Suspension Order's acceptance, subject to a five-month suspension period, refund, the outcome of the hearing, and the modifications made in TIGT's December 21, 2015 compliance filing, of TIGT's proposed CRM charge. The FERC Administrative Law Judge assigned to the proceeding has issued an order establishing the procedural schedule and TIGT, the FERC's Trial Staff, and other participants that successfully intervened are actively participating in the litigated proceeding to address those rate and tariff matters set for hearing by the FERC in its Suspension Order. On January 27, 2016, the FERC issued a tolling order to afford the FERC additional time for consideration of matters raised on rehearing regarding the Suspension Order. Additional FERC action is pending.

2014 Trailblazer Rate Settlement

On January 22, 2014, Trailblazer, the FERC's Trial Staff, and the active parties in the pipeline's general rate case finalized a settlement in principle resolving the pending rate issues, including: (i) establishing transportation rates, as well as FL&U charges; (ii) providing a limited profit sharing arrangement for certain revenues earned from interruptible and short-term firm transport; and (iii) setting the minimum and maximum time that can elapse before Trailblazer's next rate case at the FERC. Trailblazer filed a motion with the FERC's Chief Administrative Law Judge to accept the settlement rates on an interim basis ("Interim Rates") while the participants finalized a definitive settlement. The Chief Administrative Law Judge accepted the Interim Rates effective February 1, 2014. On February 24, 2014, Trailblazer filed an uncontested offer of settlement ("Stipulation and Agreement") among active party shippers. The Stipulation and Agreement established the Interim Rates as final settlement rates effective February 1, 2014, subject to the issuance of refunds to certain shippers for January 2014 transportation services and revised fuel and lost and unaccounted for rates, effective July 1, 2014. On March 11, 2014, the Presiding Administrative Law Judge certified the Stipulation and Agreement. On May 29, 2014, the FERC approved the Stipulation and Agreement. On June 30, 2014, Trailblazer filed tariff sheets to implement the Stipulation and Agreement effective July 1, 2014. Estimated refunds were reserved from revenues recorded in January 2014. On July 1, 2014, Trailblazer submitted refunds to its customers for amounts collected in excess of amounts that would have been collected under the Settlement Rates, with interest, and on July 18, 2014, filed a report of refunds with the FERC. The FERC issued orders accepting the tariff sheets with the requested effective date of July 1, 2014 and accepting the refund report filing on July 25, 2014 and August 7, 2014, respectively. Per the terms of the Stipulation and Agreement, Trailblazer is required to file a new rate case by January 1, 2019, and no settling party was permitted to file a change to the settlement rates before January 1, 2016.

Trailblazer Annual Fuel Tracker Filing

On April 1, 2015, Trailblazer made its annual fuel tracker filing with a proposed effective date of May 1, 2015 in Docket No. RP15-841-000. This filing incorporates the revised fuel tracker and power cost tracker mechanisms agreed to in the Stipulation and Agreement, which resolves all outstanding issues related to Trailblazer fuel recoveries. The FERC approved this filing on April 23, 2015.

Trailblazer Notice to Vacate Authorization for the Niobrara Lateral Project

On December 18, 2015, Trailblazer filed a notice in Docket No. CP15-27-000 informing FERC that, based upon current market conditions, it will not be constructing certain gas supply facilities located in Weld County, Colorado and Kimball County, Nebraska interconnecting Trailblazer to the Rockies Express pipeline system, referred to as the Niobrara Lateral.

Initiation of Service on the Pony Express System

In 2013, TIGT received FERC authorization to remove from natural gas service approximately 433 miles of mainline natural gas pipeline facilities, along with associated rights of way and other related equipment (collectively, the "Pony Express Assets"), abandon those assets by sale to Pony Express for redeployment to provide transportation of oil as part of the Pony Express System, and construct certain replacement facilities. The construction of the Pony Express System consisted of three primary phases: (1) conversion of 433 miles of the Pony Express Assets from a natural gas pipeline into a crude oil pipeline; (2) construction of an approximately 265 mile extension from the converted pipeline to Cushing, Oklahoma; and (3) construction of an approximate 66 mile lateral in Northeast Colorado. The facilities constructed in phases (1) and (2) of the Pony Express System were placed in service in the fall of 2014. The lateral in Northeast Colorado constructed under phase (3) was placed in service during the second quarter of 2015. Following completion of the lateral in Northeast Colorado, the total system design capacity of the Pony Express System was approximately 320,000 bbls/d. Approximately 90% of the pipeline capacity is committed to contract shippers under 5 year firm contracts and at least 10% is reserved for non-contract shippers.

In anticipation of completing the construction of various facilities and commencing various transportation services three petitions for declaratory orders were submitted over time to the FERC by Pony Express, and certain joint tariff upstream pipelines interconnected with Pony Express to address considerations related to the Pony Express System, local services and rate structures, joint tariff services and rate structures, cost recovery, prorationing policies, committed shipper contract provisions, and other matters. In response to these petitions, the FERC issued declaratory orders (two in 2012 and one in 2014) granting each of the three petitions.

Thereafter, Pony Express made certain public tariff filings with the FERC to establish initial tariff rates and initial tariff rules and regulations for oil transportation services as each service was commenced upon completion of facilities. Initial local tariff non-contract rates from the Guernsey origin, along with initial Rules and Regulations for all services, were filed to be effective October 1, 2014. Initial local tariff contract rates from the Guernsey origin were filed to be effective November 1, 2014. Initial joint tariff contract rates for oil received from Belle Fourche Pipeline were filed to be effective November 1, 2014. Initial joint tariff non-contract and contract rates for oil received from Hiland Pipeline were filed to be effective January 1, 2015, but contract service under the Hiland joint tariff did not commence until April 1, 2015. Initial local tariff non-contract rates from origins on the Northeast Colorado lateral were filed to be effective April 2, 2015. Initial local tariff contract rates from origins on the Northeast Colorado lateral were filed to be effective June 1, 2015. Following these initial tariff filings, additional filings were made in 2015 for each contract and non-contract rate service provided by Pony Express to implement a 4.6% rate increase related to the annual FERC index adjustment. The increases became effective during the third and fourth quarters of 2015 in accordance with the provisions of various shipper contracts with respect to contract rates, and in accordance with FERC regulations with respect to non-contract rates.

Compliance with 2014 FERC Show Cause Order Issued to All Interstate Pipelines Regarding Notice of Offers to Purchase Released Capacity

On March 20, 2014, the FERC issued an Order to Show Cause to all interstate natural gas pipelines requiring the pipelines to revise their respective FERC Gas Tariffs to provide for the posting of offers to purchase released capacity as required by 18 C.F.R. §284.8(d). Both TIGT and Trailblazer submitted compliance filings proposing revisions to their respective tariffs, and the FERC accepted their compliance filings effective October 21, 2014.

FERC; Market Behavior Rules; Posting and Reporting Requirement; Other Enforcement Authorities

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 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. 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 policy statements 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, including the disgorgement of unjust profits.

EPAct 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.

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.

Further, the Federal Trade Commission, or FTC, has the authority under the Federal Trade Commission Act, or FTCA, and the Energy Independence and Security Act of 2007, or EISA, to regulate wholesale petroleum markets. The FTC has adopted anti-market manipulation rules, including prohibiting fraud and deceit in connection with the purchase or sale of certain petroleum products, and prohibiting omissions of material information which distort or are likely to distort market conditions for such products. In addition to other enforcement powers it has under the FTCA, the FTC can sue violators under EISA and request that a court impose fines of up to $1 million per violation per day. FERC also has the authority under the ICA to regulate the interstate transportation of petroleum on common carrier pipelines, including whether a pipeline's rates or rules and regulations for service are "just and reasonable." Among other enforcement powers, FERC can order prospective rate changes, suspend the effectiveness of rates, and order reparations for damages.

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, or HCAs, where a leak or rupture could potentially do the most harm.

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 amended the Pipeline Safety Improvement Act of 2002, 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. This legislation also requires the U.S. Department of Transportation to study and report to Congress on other areas of pipeline safety, including expanding the reach of the integrity management regulations beyond high consequences areas, but restricts the U.S. Department of Transportation from promulgating expanded integrity management rules during the review period and for a period following submission of its report to Congress unless the rulemaking is needed to address a present condition that poses a risk to public safety, property or the environment. PHMSA issued a final rule effective October 25, 2013 that implemented aspects of the new legislation. Among other things, the final rule increases the maximum civil penalties for violations of pipeline safety statutes or regulations, broadens PHMSA's authority to submit information requests, and provides additional detail regarding PHMSA's corrective action authority.

Additionally, PHMSA is also currently considering changes to its regulations. In October 2015, PHMSA issued a notice of proposed rule-making to its hazardous liquid pipeline safety regulations. Among other things, the proposed regulations would expand the current leak-detection requirements, apply new, more conservative repair criteria and establish timelines for inspecting pipeline facilities potentially affected by an extreme weather event or natural disaster. The proposal would also increase the stringency of integrity management program requirements and set deadlines for the use of internal inspection tools on certain systems. Further, 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. TIGT continues to investigate and, when necessary, report to PHMSA the miles of pipeline for which it has incomplete records for maximum allowable operating pressure, or 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 pipelines. At the state level, several states have passed legislation or promulgated rulemaking dealing with pipeline safety. 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.

Pipeline Integrity Issues

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 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. Trailblazer recently conducted smart tool surveys and preliminary analysis on segments of its natural gas pipeline to evaluate the growth rate of corrosion downstream of compressor stations. Trailblazer currently believes that approximately 25 - 35 miles of pipe will likely need to be repaired or replaced in order for the pipeline to operate at its MAOP of 1,000 pounds per square inch. Such repair or replacement will likely occur over a period of years, depending upon final assessment of corrosion growth rates and the remediation and repair plan implemented by Trailblazer. Trailblazer is currently operating at less than its current MAOP, public notice of which was first provided in June 2014. The current pressure reduction is not expected to prevent Trailblazer from fulfilling its firm service obligations at existing subscription levels and to date it has not had a material adverse financial impact on us.

During 2015, Trailblazer completed 32 excavation digs at an aggregate cost of approximately $1.3 million based on preliminary analysis of the smart tool surveys performed in 2014. Segments of the Trailblazer Pipeline that require full replacement are currently expected to cost in the range of approximately $2.2 million to $2.7 million per mile. Repair costs on sections of the pipeline that do not require full replacement are expected to be less on a per mile basis. Trailblazer is continuing to develop a remediation and repair plan, which involves, among other things, finalizing cost recovery options, establishing project scope and timing and setting an overall project budget. In 2016, Trailblazer intends to replace approximately 8 miles of pipe at an estimated cost of $21.5 million. Trailblazer is currently exploring all possible cost recovery options. It may not ultimately be able to recover any or all of such out of pocket costs unless and until Trailblazer recovers them through a general rate increase or other FERC-approved recovery mechanism, or through negotiated rate agreements with its customers.

In connection with our acquisition of the Trailblazer Pipeline, Tallgrass Development agreed to contractually indemnify TEP for any out of pocket costs incurred between April 1, 2014 and April 1, 2017 related to repairing or remediating the Trailblazer Pipeline, to the extent that such actions are necessitated by external corrosion caused by the pipeline's disbonded Hi-Melt CTE coating. The contractual indemnity provided by Tallgrass Development is currently capped at $20 million and is subject to an annual $1.5 million deductible. We 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 pipelines, which expenditures could be material.

In addition, we may be subject to enforcement actions and penalties for failure to comply with pipeline regulations. For example, on March 12, 2015, an event occurred at the Yoder Pump Station in Goshen County, Wyoming, related to repair and replacement activities resulting in a spill of approximately 300 bbls of crude oil. In this instance, the remediation activities have been completed without material cost to the Pony Express System and the matters have been closed by the applicable agencies. In late 2015, anomalies were detected on the portion of the Pony Express System's pipeline that was converted from gas service. These anomalies were reported to PHMSA on December 2, 2015. Pony Express is continuing to evaluate and remediate these issues on the converted pipeline section of the Pony Express System. Tallgrass Development has agreed to contractually indemnify us for out of pocket costs incurred to repair, replace or remediate anomalies in any part of the Pony Express System's pipeline that was converted from gas service to the extent such anomalies are identified by in-line inspection tools during the period from January 1, 2015 until January 1, 2019. The contractual indemnity provided by Tallgrass Development is capped at $11 million and is subject to an annual $1 million deductible.

From time to time, our pipelines 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, on June 13, 2013, a failure occurred on a segment of the TIGT System in Goshen County, Wyoming, resulting in the release of natural gas and the issuance of a Corrective Action Order, or CAO, by PHMSA. The line was promptly brought back into service and the failure did not cause any known injuries, fatalities, fires or evacuations. Pursuant to a letter dated August 14, 2015, PHMSA informed TIGT that it had complied with the terms of the CAO and declared the case closed. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties and we may also be subject to private civil liability for such matters.

For additional information, see Note 17 – *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

General

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. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we can handle or dispose of our wastes, requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operations, regulating future construction activities to mitigate harm to threatened or endangered species, wetlands and migratory birds, and requiring the installation and operation of pollution control or seismic monitoring equipment. The cost of complying with these laws and regulations can be significant, and we expect to incur significant compliance costs in the future as new, more stringent requirements are adopted and implemented.

Failure to comply with existing environmental laws, regulations, permits, approvals or authorizations or to meet the requirements of new environmental laws, regulations or permits, approvals and authorizations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and/or temporary or permanent interruptions in our operations that could influence our business, financial position, results of operations and prospects. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released. The costs and liabilities resulting from a failure to comply with environmental laws and regulations could negatively affect our business, financial position, results of operations and prospects. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

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 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.

Historically, our total expenditures for environmental control measures and for remediation have not been significant in relation to our consolidated financial position or results of operations. It is reasonably likely, however, that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business.

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

Air Emissions

Our operations are subject to the federal Clean Air Act, or CAA, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions (including GHG emissions, as discussed below), obtain and strictly comply with air permits containing various emissions and operational limitations and/or install emission control equipment. We may be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

In September 2015, the EPA issued a proposed rule under the New Source Performance Standard Program, or NSPS Program, to limit methane emissions from the oil and gas and transmission sectors. The proposed rule would update and expand the NSPS Program by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. Also, in January 2016, the Bureau of Land Management of the U.S. Department of the Interior, or BLM, proposed new rules to reduce venting, flaring and leaks during oil and natural gas production activities onshore Federal and Indian lands.

Developments in GHG Regulations

Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas and products produced from crude oil, are examples of GHGs. The EPA has determined that the emission of GHGs present an endangerment to public health and the environment because emissions of such gases contribute to the warming of the Earth's atmosphere and other climatic changes. Various laws and regulations exist or are under development that seek to regulate the emission of such GHGs, including 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. There have also been efforts to regulate GHGs at an international level, most recently in the Paris Agreement, negotiated in December 2015, which aims to limit global GHG emissions.

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 pipelines, 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. In addition, new laws, regulations, or programs adopted could also impact our customers' operations or the overall demand for fossil fuels. Any of the foregoing could have an adverse effect on our business, financial position, results of operations and prospects.

Regulation of Hydraulic Fracturing

A sizeable portion of the hydrocarbons we transport, process, and store comes from hydraulically fractured wells. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process typically involves the injection of water, sand and a small percentage of chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is regulated by state agencies, typically the state's oil and gas commission. A number of federal agencies, including the EPA and the U.S. Department of Energy, are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In addition, some states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. Other states, including states in which we operate, have restrictions on produced water storage from hydraulic fracturing operations and the operation of produced water disposal wells. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for our customers to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing could also reduce the volume of crude oil, natural gas, and NGLs that our customers produce, and could thereby adversely affect our revenues and results of operations.

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, the Comprehensive Environmental Response, Compensation, and Liability Act, or 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 Resource Conservation and Recovery Act, or 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 resulting from 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 business, financial position, results of operations and prospects or otherwise impose limits or restrictions on our operations or those of our customers.

In some cases, we 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.

Our produced water disposal operations require us to comply with the Class II well standards under the federal Safe Drinking Water Act, or SDWA. The SDWA imposes requirements on owners and operators of Class II wells through the EPA's Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. Our disposal wells are also subject to comparable state laws and regulations. Compliance with current and future laws and regulations regarding our produced water disposal wells may impose substantial costs and restrictions on our produced water disposal operations, as well as adversely affect demand for our produced water disposal services. State and federal regulatory agencies recently have focused on a possible connection between the operation of produced water injection wells used for oil and gas waste disposal and minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In some instances, operators of produced water injection wells in the vicinity of minor seismic events have been ordered to reduce produced water injection volumes or suspend operations. Regulatory agencies are continuing to study possible linkage between produced water injection activity and induced seismicity. These developments could result in additional regulation of produced water injection wells, such regulations could impose additional costs and restrictions on our produced water disposal operations.

Federal and State Waters

The Federal Water Pollution Control Act, also known as the Clean Water Act, or the CWA, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including petroleum products, into state waters or waters of the United States. The EPA and the U.S. Army Corps of Engineers recently adopted a rule to clarify the meaning of the term "waters of the United States" with respect to federal jurisdiction. Many interested parties believe that the proposed rule expands federal jurisdiction under the CWA. Regulations promulgated pursuant to these laws require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System, or NPDES, permits and/or state permits authorizing these discharges. The CWA and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the CWA and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater. We believe that we are in substantial compliance with the CWA permitting requirements as well as the conditions imposed thereunder and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

The primary federal law related to oil spill liability is the Oil Pollution Act, or OPA, which amends and augments oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. 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. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Endangered Species

The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of 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 National Environmental Policy Act, or 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 or other federal 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, record keeping requirements, and monitoring of occupational exposure to regulated substances.

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 heating demand. We do not expect our crude oil transportation segment to encounter market based seasonality. Nevertheless, because a high percentage of our natural gas transportation and storage and crude oil transportation revenues are derived from firm capacity reservation fees under long-term firm fee contracts, our revenues attributable to those segments 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. We also experience some seasonality in our maintenance, repair, overhaul, integrity, and other projects, as warm weather months are most conducive to efficient execution of these activities.

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 primarily to leases, easements, rights-of-way, permits or licenses between us, as grantee, and a third party, as grantor. We believe that we have satisfactory title to all of our material parcels that we own in fee and the material parcels in which our interest derives from leases, easements, rights-of-way, permits and licenses, and we have no knowledge of any challenge that we expect will impact our title to such assets or their underlying fee title in any material respect.

Some of the leases, easements, rights-of-way, permits and licenses we acquire, including those we acquired in the IPO, require the consent of the grantor for the assignment/conveyance of such rights, which in certain instances is a governmental entity. The transferor, such as Tallgrass Development 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, Tallgrass Development 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 Tallgrass Development holding the title to any part of such assets subject to future conveyance or as our nominee.

Insurance

We generally share insurance coverage with Tallgrass Development and TEGP, for which we reimburse Tallgrass Development and its affiliates pursuant to the terms of the TEP Omnibus Agreement. The Tallgrass Development insurance program includes general and excess liability insurance, auto liability insurance, workers' compensation insurance, property and director and officer liability insurance. 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 Tallgrass Energy Holdings 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 TEP Omnibus Agreement and our partnership agreement, we reimburse Tallgrass Development and our general partner, respectively, for the provision of various general and administrative services for our benefit and for direct expenses incurred by Tallgrass Development or our general partner on our behalf, including services performed and expenses incurred by our executive management personnel in connection with our business and affairs.

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 quarterly distributions on our common units at the current distribution level, 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 units.

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 services we provide to customers pursuant to firm fee contracts and the volume of customer products we transport, store, process, gather, treat and dispose using our assets;
- our ability to renew or replace expiring long-term firm fee contracts with other long-term firm fee contracts;
- the creditworthiness of our customers, particularly customers who are subject to firm fee contracts;
- our ability to complete and integrate acquisitions from Tallgrass Development or from third parties;
- the level of production of crude oil, natural gas and other hydrocarbons and the resultant market prices of natural gas, NGLs, crude oil and other hydrocarbons;
- regional, domestic and foreign supply and perceptions of supply of natural gas, crude oil and other hydrocarbons;
- the level of demand and perceptions of demand in end-user markets we directly or indirectly serve;
- actual and anticipated future prices of natural gas, crude oil and other commodities (and the volatility thereof);
- applicable laws and regulations affecting our and our customers' business, including the market for natural gas, crude oil, other hydrocarbons and water, the rates we can charge on our assets, how we contract for services, our existing contracts, our operating costs or our operating flexibility;

- prevailing economic conditions;
- changes in the fees we charge for our services, including firm services and interruptible services;
- the effect of seasonal variations in temperature and climate on the amount of customer products we are able to transport, store, process, gather, treat and dispose using our assets;
- the realized pricing impacts on revenues and expenses that are directly related to commodity prices;
- the level of competition from other midstream energy companies in our geographic markets;
- the level of our operating and maintenance costs;
- damage to our assets and surrounding properties caused by earthquakes, floods, fires, severe weather, explosions and other natural disasters or acts of terrorism;
- outages in our assets;
- the relationship between natural gas and NGL prices and resulting effect on processing margins; and
- leaks or accidental releases of hazardous materials into the environment, whether as a result of human error or otherwise.

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

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

If we are not able to renew or replace expiring customer contracts at favorable rates or on a long-term basis, our financial condition, results of operation, cash flows and ability to make cash distributions to our unitholders will be adversely affected.

We transport, store and process a substantial majority of our customers' products, including natural gas, crude oil and water, on our systems under long-term firm fee contracts with terms of various durations. For the year ended December 31, 2015, approximately 94% of our natural gas transportation and storage revenues were generated under firm fee transportation and storage contracts and approximately 94% of our crude oil transportation revenues were generated under firm fee transportation contracts. As of December 31, 2015, the weighted average remaining life of our long-term natural gas transportation contracts and natural gas storage contracts was approximately two and six years, respectively, the weighted average remaining life of our oil transportation contracts was approximately four years, and the weighted average remaining life of our natural gas processing contracts was approximately three 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 natural gas 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 621 MMcf/d for the year ended December 31, 2015 and transportation services revenue decreased from $143.4 million to $94.9 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. In the current commodity environment, which has included significant price reduction and volatility in crude oil, natural gas and other hydrocarbons over the past 18 months, we expect customers will generally be less likely to enter into long-term firm fee contracts until prices recover and stability returns to the commodity markets. 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 profile 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 competing services to our markets;
- the macroeconomic factors affecting crude oil and natural gas gathering economics for our current and potential customers;
- the balance of supply and demand for natural gas, crude oil and other hydrocarbons, on a short-term, seasonal and long-term basis, in the markets we serve;
- the extent to which the current and potential 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.

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 condition, cash flows, 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. Our long-term firm fee contracts obligate our customers to pay demand charges regardless of whether they utilize our assets, except for certain circumstances outlined in applicable customer agreements. As a result, during the term of our long-term firm fee 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 or crude oil transported. The recent decline in natural gas and crude oil prices has negatively impacted the financial condition of our customers and further declines, sustained lower prices, or continued volatility could impact their ability to meet their financial obligations to us. Further, our contract counterparties may not perform or adhere to our existing or future contractual arrangements. To the extent one or more of our contract counterparties is in financial distress or commences bankruptcy proceedings, contracts with these counterparties may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Any material nonpayment or nonperformance by our contract counterparties due to inability or unwillingness to perform or adhere to contractual arrangements could have a material 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. In accordance with FERC regulations and our own internal credit policies, counterparties with investment grade credit ratings are deemed able to meet their financial obligations to us without requiring credit support in the form of a letter of credit or prepayment. With the recent decline in natural gas and crude oil prices and the corresponding deterioration of the financial condition of some of our customers, it is possible that some may lose their investment grade credit rating. If this were to occur, we would likely ask for credit support and the customer may be unwilling or unable to provide it due to liquidity constraints. To the extent our procedures and policies prove to be inadequate or we are unable to obtain credit support, our financial position and results of operations may be negatively impacted.

Some of our counterparties may be highly leveraged or have limited financial resources and are 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. As seen with the recent decline in crude oil prices, prices for crude oil and natural gas are subject to large fluctuations in response to changes in supply and demand, market uncertainty and a variety of other factors that are beyond our control. Such volatility in commodity prices might have an impact on many of our counterparties and their ability to borrow and obtain additional capital on attractive terms, 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.

We depend on certain key customers for a significant portion of our revenues and are exposed to credit risks of these customers. The loss of or material nonpayment or nonperformance by any of these key customers could adversely affect our cash flow and results of operations.

We rely on certain key customers for a portion of revenues. For example, for the year ended December 31, 2015, Continental Resources and Shell accounted for approximately 28% and 19% of our segment revenue in the Crude Oil Transportation & Logistics segment, respectively, and approximately 16% and 15% of our revenues on a consolidated basis, respectively. In addition, for the year ended December 31, 2015, 55% of our consolidated revenues were represented by the top ten customers on our Pony Express System.

We may be unable to negotiate extensions or replacements of contracts with key customers on favorable terms. In addition, some of these key customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. To the extent one or more of our key customers is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Additionally, many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payments or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. The loss of all or even a portion of the contracted volumes of these key customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

The revenue in our Processing and Logistics segment largely depends on the amount of natural gas that our customers actually deliver to our natural gas processing plants.

As of December 31, 2015, approximately 92% of our reserved capacity at our Casper and Douglas natural gas processing plants was subject to firm or volumetric fee contracts, with the majority of the fee revenue being based on the volumes actually processed (the remaining 8% was subject to commodity sensitive contracts such as percent of proceeds or keep whole processing contracts). On these volumetric fee contracts, our revenue is largely tied to the amount of natural gas that our customers actually deliver our Casper and Douglas plants for processing. Unlike many pipeline transportation customers, our natural gas processing customers are not generally subject to "take or pay" obligations. Thus, if our natural gas processing customers do not produce natural gas and deliver that natural gas to our processing plants to be processed, revenue for our Processing and Logistics segment will decline. As natural gas, crude oil or NGL prices decline, which has been the case since the latter half of 2014, our customers will likely make less money from the production of natural gas, crude oil or NGLs than it costs them to produce it. If that happens, our customers may not continue to produce natural gas and our revenue will decline. The decreased commodity prices in late 2015 and into early 2016 contributed to a significant drop in actual and anticipated volumes from several producers from which TMID receives natural gas for processing. If a gradual recovery of commodity prices and a corresponding increase in volumes over time to TMID does not occur, we could have an impairment of the goodwill at the TMID reporting unit, which is a component of our Processing & Logistics segment, and our revenue will decline. In addition, the fees our customers pay to reserve capacity at our processing plants may not deter those customers from processing their natural gas volumes at other facilities, with whom they may have had prior arrangements or otherwise.

We have only recently commenced operating our newly acquired water business services assets in Weld County, Colorado, and we may not achieve all the benefits anticipated.

On December 16, 2015, we purchased water business services assets located in Weld County, Colorado, including a gathering and disposal system for water removed from a well as a byproduct of exploration and production activities, which we generally refer to as produced water. Gathering and disposal of produced water is a new water business activity for us, as our water business operations were previously focused on the transportation of freshwater. Operating a produced water gathering and disposal system involves different risks and requires different operating strategies and managerial expertise than our current operations. In addition, gathering and disposing produced water is subject to more stringent laws and regulations than transporting freshwater, particularly those related to environmental matters. Failure to timely and successfully develop this new water business activity in conjunction with our existing operations could result in our failure to achieve the benefits anticipated and may have a material adverse effect on our business, financial condition and results of operations.

We may not be able to compete effectively in our midstream services activities and our business is subject to the risk of a capacity overbuild of midstream energy infrastructure in the areas where we operate.

We face competition in all aspects of our business and may not be able to compete effectively against our competitors. In general, competition comes from a wide variety of players in a wide variety of contexts, including new entrants and existing players and in connection with day-to-day business, expansion capital projects, acquisitions and joint venture activities. Some of our competitors have capital resources greater than ours and control greater supplies of crude oil, natural gas or NGLs.

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. In addition, some of our competitors have assets in closer proximity to hydrocarbon 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 our natural gas pipeline systems and transport gas to customers in the Rocky Mountain and Midwest regions of the United States. Pony Express also competes with rail facilities, which can provide more delivery optionality to crude oil producers and marketers looking to capitalize on basis differentials between two primary crude oil benchmarks (West Texas Intermediate Crude and Brent Crude). Other crude oil pipeline projects have been announced recently that would compete directly with our Pony Express System. Furthermore, Tallgrass Development and its affiliates are not limited in their ability to compete with us.

Our competitors may expand or construct new midstream services assets that would create additional competition for the services we provide to our customers, or our customers may develop their own facilities in lieu of using ours. A significant driver of competition in some of the markets where we operate (including, for example, the Rocky Mountain region) has seen the rapid development of new midstream energy infrastructure capacity in recent years. As a result, we are exposed to the risk that the areas in which we operate become overbuilt, resulting in an excess of midstream energy infrastructure capacity. If we experience a significant capacity overbuild in one or more of the areas where we operate, it could have a significant adverse impact on our financial position, cash flows and ability to pay or increase distributions to our unitholders. For example, our competitors in these areas could substantially decrease the prices at which they offer their services, and we may be unable to compete effectively. This could materially impair our cash flows and ability to make distributions to our unitholders.

Further, natural gas as a fuel, and fuels derived from crude oil, compete with other forms of energy available to users, including electricity, coal and other liquid fuels. Increased demand for such forms of energy at the expense of natural gas or fuels derived from crude oil 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 fee 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 and crude oil 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 or crude oil.

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 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 TEP 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. The recent downturn in the energy capital markets has negatively impacted the cost at which we can issue public debt and equity and has altered some of our financing plans. 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.

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 revolving 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. While the recent downturn in the energy capital markets has not changed our business plans, it has altered some of our financing strategies.

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.

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 & Logistics segment operates under three types of contracts, two of which directly expose our cash flows to increases and decreases in the price of natural gas and NGLs: percent of proceeds and keep whole processing contracts. As of December 31, 2015, approximately 8% of the reserved capacity in our Processing & Logistics segment was contracted under percent of proceeds or keep whole processing contracts. We do not currently hedge the commodity exposure inherent in these types of processing contracts, and as a result, our revenues and results of operations are impacted by fluctuations in the prices of natural gas and NGLs.

Percent of proceeds processing contracts generally provide upside in high commodity price environments, but result in lower margins in low commodity price environments. Under keep whole processing contracts, our revenues and our cash flows generally 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 related to the market price of oil and as a result any significant changes in oil prices could also indirectly impact our operations. Indirectly, reduced commodity prices impact us through reduced exploration and production activity, which results in fewer opportunities for new business to offset natural volume declines. 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. In 2015 natural gas and oil prices declined substantially and these declines directly and indirectly resulted in lower processing volumes and realizations on our percent of proceeds and keep whole processing contracts.

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

Our assets typically connect to other pipelines or facilities owned, leased and/or operated by unaffiliated third parties, such as Phillips 66, Deeprock Development, LLC, Whiting, and others. For example, the Powder River pipeline, owned by Phillips 66, is currently the only pipeline outlet for the NGLs that we produce and thus a substantial majority of the NGLs we produce are sold to Phillips 66 at the tailgate of the Douglas plant. Accordingly, the failure to renew our agreement (which expires on December 31, 2016) with Phillips 66 without securing another outlet for the NGLs or any downtime on this pipeline as a result of maintenance or force majeure would adversely affect us.

As a further example, our Pony Express System connects to upstream joint tariff pipelines, including the Belle Fourche Pipeline owned by the True Companies (which also own and operate the Bridger Pipeline) and the Double H Pipeline owned by Kinder Morgan, Inc., which are responsible for delivering a substantial portion of the crude oil for transportation on the Pony Express System. In addition, nearly all of the crude oil we transport on the Pony Express System is either stored in crude oil tanks located on, or pumped over to downstream pipelines that interconnect through, the Deeprock Development terminal facility in Cushing, Oklahoma. The continuing operation of such third-party facilities and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable to us for any number of reasons, including 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. For example, the operations of the Bridger Pipeline's Poplar System were down for approximately five months during the first half of 2015 due to a pipeline release. Bridger declared a force majeure as a result of this event and temporarily lacked the capacity to make up volumes on other lines that directly or indirectly deliver crude oil into designated origin points on the Pony Express System or the Belle Fourche Pipeline. The largest committed shipper on the Pony Express System also declared a force majeure as a result of this incident.

If the costs to us to access and transport on these third-party pipelines or any alternative pipelines significantly increase, our ability to make cash distributions to our unitholders could be reduced. If any such increase in costs occurred, if any of these pipelines or other midstream facilities become unable to receive, transport, store or process products from our assets, or if the volumes we transport or process do not meet the 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 success depends on the supply and demand for natural gas and crude oil.

The success of our business is in many ways impacted by the supply and demand for natural gas and crude oil. For example, our business can be negatively impacted by sustained downturns in supply and demand for natural gas and crude oil in the markets that we serve, including reductions in our ability to renew contracts on favorable terms and to construct new infrastructure. Further, a portion of the demand for our water business services depends substantially on the level of expenditures by the oil and gas industry for the exploration, development and production of oil and natural gas reserves. These expenditures are generally dependent on the industry's view of future oil and natural gas prices and are sensitive to the industry's view of future economic growth and the resulting impact on demand for oil and natural gas. Declines, as well as anticipated declines, in oil and gas prices could also result in project modifications, delays or cancellations, general business disruptions, and delays in, or nonpayment of, amounts that are owed to us. These effects could have a material adverse effect on our financial condition, results of operations and cash flows.

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 domestic natural gas and crude oil supplies has been the significant growth in unconventional sources such as shale plays and the continued progression of hydraulic fracturing technology. The supply and demand for natural gas and crude oil, and therefore the future rate of growth of our business, depends 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, crude oil and NGLs;
- decisions of the members of Organization of the Petroleum Exporting Countries, or OPEC, regarding price and production controls;
- increased costs to explore for, develop, produce, gather, process and transport hydrocarbons or water;
- weather conditions, seasonal trends and hurricane disruptions;
- the nature and extent of, and changes in, governmental regulation, for example GHG legislation, taxation and hydraulic fracturing;
- perceptions of customers on the availability and price volatility of our services and natural gas and crude oil prices, particularly customers' perceptions on the volatility of natural gas and crude oil prices over the long-term;
- capacity and transportation service into, or out of, our markets; and
- petrochemical demand for NGLs.

The oil and gas industry historically has experienced periodic downturns, and is currently experiencing a period of low commodity prices. In the fourth quarter of 2014 and subsequent to December 31, 2014, the prices of crude oil, natural gas and NGLs were extremely volatile and declined significantly. Downward pressure on commodity prices continued in 2015 and the early part of 2016 and may continue for the foreseeable future. A prolonged downturn in the oil and gas industry could result in a reduction in demand for our business and could adversely affect our financial condition, results of operations and cash flows.

Any significant decrease in available supplies of hydrocarbons in our areas of operation, or redirection of existing hydrocarbon supplies to other markets, could adversely affect our business and operating results. If recent lower commodity prices are prolonged beyond our contract lives, we will likely experience lower throughput volumes and reduced cash flows.

Our business is dependent on the continued availability of natural gas and crude oil production and reserves. Production from existing wells and natural gas and crude oil supply basins with access to our assets will naturally decline over time. The amount of natural gas and crude oil 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 and/or the volume of products utilizing our assets, our customers must continually obtain adequate supplies of natural gas and crude oil.

However, the development of additional natural gas and crude oil 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 and crude oil to be produced and products delivered to our facilities. In addition, low prices for natural gas and crude oil, 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 and crude oil supplies. The current volatility and historically low prices for crude oil and refined products has led to a decline in drilling activity, production and refining of crude oil, and import levels in these areas. For example, in response to recent declines in crude oil prices, a number of producers in our areas of operation significantly reduced their capital budgets and drilling plans in 2015 and have announced further reductions in their capital budget and drilling plans for 2016. In addition, production may fluctuate for other reasons, including, for example, in the case of crude oil, the decisions made by the members of the OPEC regarding production controls. Furthermore, competition for natural gas and crude oil supplies to serve other markets could reduce the amount of natural gas and crude oil supply available for our customers. Accordingly, to maintain or increase the contracted capacity and/or the volume of products utilizing our assets, our customers must compete with others to obtain adequate supplies of natural gas and crude oil.

If new supplies of natural gas and crude oil are not obtained to replace the natural decline in volumes from existing supply basins, if natural gas and crude oil supplies are diverted to serve other markets, if environmental regulations restrict new natural gas and crude oil drilling or if OPEC does not agree to and maintain production controls, the overall demand for services on our systems will likely 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.

Our natural gas and crude oil 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.

We provide open-access interstate transportation service on our natural gas transportation systems pursuant to tariffs approved by the FERC. Our natural gas transportation and storage operations are regulated by the FERC, under the NGA, the NGPA, and EPAct 2005. The TIGT System and the Trailblazer Pipeline each operates under a tariff approved by the FERC that establishes rates and terms and conditions of service to our customers. The rates and terms of service on the Pony Express System are subject to regulation by the FERC under the ICA, and the Energy Policy Act of 1992. We provide interstate transportation service on the Pony Express System pursuant to tariffs on file with the FERC. Our NGL pipeline is leased to a third party who has obtained a temporary waiver for itself from the FERC from the tariff, filing and reporting requirements of the ICA.

Generally, the FERC's authority over natural gas facilities 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;
- customer 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.

The FERC's authority over crude oil pipelines is less broad, extending to:

- rates, rules and regulations of service;
- the form of tariffs governing rates and service;
- the maintenance of accounts and records; and
- depreciation and amortization policies.

Interstate natural gas pipelines subject to the jurisdiction of the FERC may not charge rates or impose terms and conditions of service that, upon review by the FERC, are found to be unjust, unreasonable, unduly discriminatory, or preferential. The maximum recourse rate that we may charge for our natural gas 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 natural gas 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 natural gas pipeline may charge for its services under its tariff); (ii) "discount rates" (i.e., rates offered by the natural gas pipeline to shippers at discounts vis-à-vis the recourse rates and that fall within the cost-based maximum and minimum rate levels set forth in the natural gas pipeline's tariff); and (iii) "negotiated rates" (i.e., rates negotiated and agreed to by the pipeline and the shipper for the contract term that may fall within or outside of the cost-based maximum and minimum rate levels set forth in the tariff, and which are individually filed with the FERC for review and acceptance). When capacity is available and offered for sale, the rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for) at which such capacity is sold are subject to regulatory approval and oversight. Regulators and customers on our natural gas pipeline systems 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. Customers on our natural gas pipeline systems may also dispute terms and conditions contained in our agreements, as well as the interpretation and application of our tariffs, among other things.

Rates for crude oil transportation service must be filed as a tariff with the FERC and are subject to applicable FERC regulation. The filed tariff rates include contract rates entered into with shippers willing to make long-term commitments to the pipeline to support new pipeline capacity. Contract rates generally are not subject to regulation or change by the FERC. Non-contract "walk-up" rates are available to uncommitted non-contract shippers and generally are subject to regulation and change by the FERC. Crude oil pipelines typically must reserve at least ten percent of their capacity for walk-up shippers. Contract tariff rates may be changed by Pony Express on an annual basis to reflect annual FERC index adjustments to the extent permitted by contract. Non-contract rates may be adjusted, positively or negatively, on an annual basis pursuant to a FERC indexing procedure. A crude oil pipeline may also file new tariff rates at any time, subject to contract restrictions and provisions, and FERC regulatory procedures. The filing of any indexed rate increase or other rate increase may be protested by parties having standing, subject to applicable regulatory and contract provisions, and thereby be subjected to cost-of-service review by the FERC to determine whether the proposed new rate is just and reasonable.

Under the ICA, which applies to FERC-regulated interstate liquids pipelines such as the Pony Express System, parties having standing and not restricted by contract may protest newly filed rates and terms and conditions of service within a prescribed notice period. The FERC is authorized to suspend, subject to refund, the effectiveness of a protested rate for up to seven months while it determines if the protested rate is just and reasonable. Our rates may be reduced and we may be required to issue refunds as a result of settlement or by an order of the FERC following a hearing finding that a protested rate is unjust and unreasonable. Parties having standing and not restricted by contract may file a complaint at any time regarding existing rates and terms and conditions of service. If the complaint is not resolved by settlement, the FERC may conduct a hearing and order the crude oil pipeline to make reparations going back for up to two years prior to the date on which a complaint was filed if a rate is found to be unjust and unreasonable. We cannot guarantee that any new or existing local or joint tariff rate for service on the Pony Express System would not be rejected or modified by the FERC, or subjected to refunds or reparations. While the FERC regulates rates and terms and conditions of service for transportation of crude oil in interstate commerce by pipeline, state agencies may also regulate facilities (including construction, acquisition, disposition, financing, and abandonment), rates, and terms and conditions of service for crude oil pipeline transportation in intrastate commerce. 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.

The Trailblazer Pipeline, one of our interstate natural gas pipelines, uses two types of fuel to power its compressors: (1) natural gas and (2) electric power. For the natural gas compression, customers are charged a gas retainage percentage as an in-kind reimbursement for fuel. For the electric compression, customers are charged a commodity rate for the electricity used at the pipeline’s stations. The volume of gas and cost of electric power are tracked and adjusted in annual periodic rate adjustment filings made pursuant to Trailblazer's tariff. Lost and unaccounted for gas is also tracked and adjusted in annual periodic rate adjustment filings. These costs were subject to the NGA Section 4 rate case initiated by the Trailblazer Pipeline and resolved by settlement as approved by the FERC in May 2014. On TIGT, our gas compressor fuel costs and the cost of FL&U gas, together referred to as Fuel Retention Factors, are currently 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 NGA Section 5 proceeding initiated by the FERC that we resolved with customers by a settlement approved by the FERC in September 2011. In its NGA Section 4 proceeding that was filed on October 30, 2015, TIGT proposed to replace its fixed FL&U charge with a FL&U tracker that would compensate TIGT for its actual FL&U expenses and adjust each year to reflect any previous period’s under/over collection and the forecasted FL&U expense for the upcoming period. TIGT also proposed to implement a separate power cost tracker to recover the actual power costs incurred by TIGT to power its compressors. These proposals were accepted by the FERC in its Suspension Order, subject to a five-month suspension period, to be effective May 1, 2016, subject to refund and the outcome of the hearing.

The FERC’s jurisdiction over natural gas facilities 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. With some exceptions applicable to smaller projects, auxiliary facilities, and certain facility replacements, prior to commencing construction and/or operation of new or existing interstate natural gas transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction from, or file to amend its existing certificate with, 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 delay or refusal by an agency to issue authorizations or permits as requested for one or more of these projects may mean that they will be constructed in a manner or with capital requirements that we did not anticipate or that we will not be able to pursue these projects. Such delay, modification or refusal could materially and negatively impact the additional revenues expected from these projects. The FERC does not regulate the construction, expansion, or abandonment of crude oil or NGL pipelines, whether interstate or intrastate, nor the initiation or discontinuation of services on those pipelines, provided that the action taken is not discriminatory or preferential among similarly situated shippers.

The FERC has the authority to conduct audits of regulated entities to assess compliance with FERC regulations and policies. The FERC also conducts audits to verify that the websites of interstate natural gas pipelines accurately provide information on the operations and availability of services on the pipeline. FERC regulations also require entities providing interstate natural gas and crude oil transportation services to comply with uniform terms and conditions for service, as set forth in publicly available tariffs or, as it concerns natural gas facilities, agreements for transportation and storage services executed between interstate pipelines and their customers. Natural gas transportation service agreements are generally required to conform, in all material respects, with the standard form of service agreements set forth in the natural gas pipeline's FERC-approved tariff. The pipeline and a customer may choose to enter into a non-conforming service agreement so long as this agreement is filed with, and accepted by, the FERC. In the event that the FERC finds that a natural gas transportation agreement, in whole or part, is materially non-conforming, the FERC could reject the agreement or require us to modify the agreement, or alternatively require us to modify our tariff so that the non-conforming provisions are generally available to all customers. Transportation agreements entered into with crude oil shippers are generally not subject to FERC regulation or required to be available for FERC or public review, but the rates and terms and services provided to similarly situated shippers may not be unduly discriminatory or preferential.

The FERC has promulgated rules and policies covering many aspects of our natural gas pipeline business, including regulations that require us to provide firm and interruptible transportation service on an open access basis that is not unduly discriminatory or preferential, provide internet access to current information about our available pipeline capacity and other relevant transmission 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 prevent interstate natural gas pipelines from sharing customer information with marketing affiliates, and restrict how interstate natural gas pipelines share transportation with marketing affiliates. FERC regulations require that certain transmission function personnel of interstate natural gas pipelines function independently of personnel engaged in natural gas marketing functions. Crude oil pipelines subject to the ICA must comply with FERC regulations that require the pipeline to act as a common carrier and not engage in undue discrimination or preferential treatment with respect to shippers.

FERC policies also govern how interstate natural gas pipelines respond to interconnection requests from third party facilities, including other pipelines. Generally, an interstate natural gas pipeline must grant an interconnection request upon the satisfaction of several conditions. As a consequence, an interstate natural gas pipeline faces the risk that an interconnecting third-party pipeline may pose a risk of additional competition to serve a particular market. Failure to comply with applicable provisions of the NGA, NGPA, EPAct 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, including without limitation, revocation of certain authorities, disgorgement of ill-gotten gains, and civil penalties of up to $1.0 million per day, per violation. Violations of the ICA, the Energy Policy Act of 1992, or regulations and orders promulgated by the FERC are also subject to administrative and criminal penalties and remedies, including forfeiture and individual liability.

In addition, new laws or regulations or different interpretations of existing laws or regulations applicable to our pipeline systems 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 and adversely affect our future earnings and cash flows.

The rates and the terms and conditions of our regulated assets are subject to review and possible adjustment by federal and state regulators, which could adversely affect our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

Our shippers or other interested stakeholders, such as state natural gas utility regulatory agencies, may challenge the rates or the terms and conditions of service applicable to our natural gas or crude oil pipeline tariffs, unless they have entered into agreements not to challenge such tariffs. The FERC has authority to investigate our rates and terms and conditions of service pursuant to NGA Section 5 for natural gas pipelines and the ICA for common carrier oil pipelines. Our crude oil contract shippers have generally agreed not to complain or protest rates unless they are in conflict with their contracts. FERC generally does not regulate crude oil transportation contracts, but contract rates must be filed with FERC and tariff rules and regulations generally apply to contract shippers. Our NGL pipeline is leased to a third party who obtained a temporary waiver for itself from the FERC from the tariff, filing and reporting requirements of the ICA, and during the term of the lease, we operate and maintain the pipeline at the lessee's discretion.

With regard to our natural gas pipelines, Trailblazer initiated a rate proceeding with the FERC pursuant to Section 5 of the NGA on July 1, 2013 to implement a general rate increase to its recourse rates, initiate a rolled-in rate structure for expansion facilities certificated in 2001, and adopt miscellaneous other updates to its General Terms and Conditions in its tariff. On February 24, 2014, Trailblazer submitted to the FERC an uncontested offer of settlement and stipulation to resolve the proceeding by, among other things: (a) setting new maximum recourse rates based upon a "black box" cost of service of $21.1 million, (b) revising the charges and methods for recovery of fuel (natural gas and electric power used in providing service, including for operating compressors) costs such that the actual volumes of gas and cost of electric power, as well as FL&U gas, are tracked and adjusted in annual periodic rate filings made pursuant to Trailblazer's tariff (as opposed to recover), (c) providing for revenue sharing of certain interruptible and short-term firm service revenues with eligible maximum recourse rate firm service shippers, (d) establishing a rate moratorium until January 1, 2016, and (e) requiring a general rate case to be filed no later than January 1, 2019. The FERC accepted the settlement agreement by letter order on May 29, 2014. Per the terms of the settlement, Trailblazer is required to file a new general rate case by January 1, 2019, and no customer or participant who joined the settlement (defined in the settlement as a "Settling Party") was permitted to file to change the settlement rates before January 1, 2016.

On October 30, 2015, TIGT initiated a general NGA Section 4 rate proceeding with the FERC which, among other things, seeks a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by TIGT. TIGT also proposed certain changes to the transportation rate design of its system to replace the current rate zone structure with a single "postage stamp" rate. TIGT also proposed new incremental charges, including (i) a charge for deliveries made to points without certain electronic flow measurement equipment, and (ii) a CRM charge to completely or partially reimburse TIGT for certain expenses and costs it incurs to comply with anticipated new PHMSA and EPA regulations. TIGT also proposed to replace its fixed FL&U charge with a FL&U tracker that would compensate TIGT for its actual FL&U expenses and adjust each year to reflect the previous period’s under/over collection and the forecasted FL&U expense for the upcoming period. Finally, TIGT proposed certain revisions to its FERC Gas Tariff addressing a number of rate and non-rate matters. The filing was protested by a number of participants. In FERC’s November 30, 2015 Suspension Order, the FERC accepted and suspended the proposed rates and a majority of the proposed tariff records to be effective May 1, 2016, subject to refund, certain modifications of TIGT’s proposed CRM charge, and the outcome of an evidentiary hearing. The FERC also accepted two tariff records related to *force majeure* events and reservation charge crediting to be effective December 1, 2015, subject to certain modifications. Consistent with the Suspension Order, on December 21, 2015, TIGT made a compliance filing with the FERC addressing TIGT’s proposed CRM charge and the two tariff records related to *force majeure* events and reservation charge crediting. The FERC accepted TIGT’s compliance filing on February 1, 2016. Litigation addressing the proposed rates and tariff records set for hearing is on-going.

On our interstate crude oil pipeline system, the Pony Express System, shippers may generally challenge new or existing rates at any time unless they have contractually agreed not to. As a result of settlement or by order of the FERC following hearing, our rates may be reduced. If a shipper files a lawful complaint, and if the complaint is not resolved with that shipper, to the extent the FERC determines after hearing that we have collected payment on rates that were not just and reasonable, we may be required to pay reparations to that shipper for up to two years prior to the date on which a complaint was filed. Regardless of the prospective just and reasonable rate, reparations may not be required below the last rates determined by the FERC to be just and reasonable. In other words, crude oil pipelines are not required to make reparations that refund revenues collected pursuant to rates previously determined to be just and reasonable.

Successful challenges to rates charged on our natural gas and crude oil pipeline systems, or to the terms and conditions of service on those systems, could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

Constructing new assets subjects us to risks of project delays, cost overruns and lower-than-anticipated volumes of natural gas or crude oil 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. Pony Express completed its approximately 698-mile crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma during 2014 and its approximately 66-mile lateral in Northeast Colorado in the first half of 2015. 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 announced 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 and crude oil 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.

We are subject to numerous hazards and operational risks.

Our operations are subject to all the risks and hazards typically associated with transportation, storage, processing, gathering and disposing of hydrocarbons and water. 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 crude oil, natural gas and other hydrocarbons or hazardous materials, including water from hydraulic fracturing;
- leaks, migrations or losses of natural gas and crude oil as a result of the malfunction of equipment or facilities;
- outages at our facilities;
- ruptures, fires, leaks 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.

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 our assets, including certain segments of our pipeline systems 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 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 in Goshen County that failed on June 13, 2013. In August 2015, PHMSA informed us that TIGT had fully complied with the terms of the Corrective Action Order related to that incident and stated that no further action is contemplated. However, 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 insured or fully insured against all risks that could affect our business, including losses from environmental accidents. For example, we do not maintain business interruption insurance in the type and amount to cover all possible losses. In addition, we do not carry insurance for certain environmental exposures, including but not limited to potential environmental fines and penalties, certain business interruptions, 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 one or more of our insured assets, any insurance proceeds that we may receive in respect thereof may be insufficient to effect a restoration of such asset to the condition that existed prior to such loss. In addition, we are either not insured or not fully insured with respect to the legal proceedings described in Note 17 – *Legal and Environmental Matters* to the consolidated financial statements and may, depending upon the circumstances, need to pay self-insured retention amounts prior to having losses covered by the insurance providers. 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 have elected and may elect in the future to self-insure a portion of our risks of loss. 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. 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 systems 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 owners and operators of pipelines 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 HCAs.

Our 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 systems and determine the pressures at which our pipeline systems can operate. The Pipeline Safety Act of 2011 enacted January 3, 2012, amends the Pipeline Safety Improvement 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 MAOP 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.

In August 2012, PHMSA published rules to update pipeline safety regulations to reflect provisions included in the Pipeline Safety Act of 2011, including increasing maximum civil penalties from $0.1 million to $0.2 million per violation per day of violation and from $1.0 million to $2.0 million as a maximum amount for a related series of violations as well as changing PHMSA's enforcement process.

The ultimate costs of compliance with the integrity management rules are difficult to predict. 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. Trailblazer recently conducted smart tool surveys and preliminary analysis on segments of its natural gas pipeline to evaluate the growth rate of corrosion downstream of compressor stations. Trailblazer currently believes that approximately 25 - 35 miles of pipe will likely need to be repaired or replaced in order for the pipeline to operate at its MAOP of 1,000 pounds per square inch. Such repair or replacement will likely occur over a period of years, depending upon final assessment of corrosion growth rates and the remediation and repair plan implemented by Trailblazer. Trailblazer is currently operating at less than its current MAOP, public notice of which was first provided in June 2014. The current pressure reduction is not expected to prevent Trailblazer from fulfilling its firm service obligations at existing subscription levels and to date it has not had a material adverse financial impact on us.

During 2015, Trailblazer completed 32 excavation digs at an aggregate cost of approximately $1.3 million based on preliminary analysis of the smart tool surveys performed in 2014. Segments of the Trailblazer Pipeline that require full replacement are currently expected to cost in the range of approximately $2.2 million to $2.7 million per mile. Repair costs on sections of the pipeline that do not require full replacement are expected to be less on a per mile basis. Trailblazer is continuing to develop a remediation and repair plan, which involves, among other things, finalizing cost recovery options, establishing project scope and timing and setting an overall project budget. In 2016, Trailblazer intends to replace approximately 8 miles of pipe at an estimated cost of $21.5 million. Trailblazer is currently exploring all possible cost recovery options. It may not ultimately be able to recover any or all of such out of pocket costs unless and until Trailblazer recovers them through a general rate increase or other FERC-approved recovery mechanism, or through negotiated rate agreements with its customers.

In connection with our acquisition of the Trailblazer Pipeline, Tallgrass Development agreed to contractually indemnify TEP for any out of pocket costs incurred between April 1, 2014 and April 1, 2017 related to repairing or remediating the Trailblazer Pipeline, to the extent that such actions are necessitated by external corrosion caused by the pipeline's disbonded Hi-Melt CTE coating. The contractual indemnity provided by Tallgrass Development is currently capped at $20 million and is subject to an annual $1.5 million deductible. We 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 pipelines, which expenditures could be material.

Additionally, we had several minor incidents in 2014 and 2015 on the Pony Express System that we reported to PHMSA during final commissioning and since the line has been placed into commercial service. In each of these cases, which released between 0.5 and 300 bbls of crude oil, the remediation activities have been completed without material cost to the Pony Express System, and the matters have been closed by the applicable agencies. In late 2015, anomalies were detected on the portion of the Pony Express System's pipeline that was converted from gas service. These anomalies were reported to PHMSA on December 2, 2015. Pony Express is continuing to evaluate and remediate these issues on the converted pipeline section of the Pony Express System. Tallgrass Development has agreed to contractually indemnify us for out of pocket costs incurred to repair, replace or remediate anomalies in any part of the Pony Express System's pipeline that was converted from gas service to the extent such anomalies are identified by in-line inspection tools during the period from January 1, 2015 until January 1, 2019. The contractual indemnity provided by Tallgrass Development is capped at $11 million and is subject to an annual $1 million deductible.

The Pony Express System is a newly commissioned crude oil pipeline and these integrity issues may continue for the foreseeable future. There can be no assurance as to the amount or timing of future expenditures required to remediate or resolve these issues, and actual future expenditures may be different from the amounts we currently anticipate. These integrity issues could have a material adverse effect on our business, financial position, results of operations and prospects.

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 MAOP 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. TIGT continues to investigate and, when necessary, report to PHMSA the miles of pipeline for which it has 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 natural gas pipeline systems. These specific requirements do not currently apply to crude oil pipelines, but forthcoming regulations implementing the Pipeline Safety Act of 2011 likely will expand the scope of regulation applicable to crude oil pipelines. 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. In addition, we may be subject to enforcement actions and penalties for failure to comply with pipeline regulations. 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.

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

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement will be open for signing on April 22, 2016 and will require countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. Following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA adopted two sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles and another that regulates emissions of GHGs from certain large stationary sources. The EPA has also expanded its existing GHG emissions reporting requirements to include upstream petroleum and natural gas systems that emit 25,000 metric tons or more of CO2 equivalent per year. 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. Furthermore, in August 2015, the EPA proposed changes to its regulations imposing more stringent controls on methane and volatile organic compounds emissions from oil and gas development, production, and transportation operations. A final rule is expected in 2016. The Administration has also announced that other federal agencies, including the BLM, the PHMSA, and the U.S. Department of Energy will impose new or more stringent regulations on the oil and gas sector that are designed to reduce methane emissions. In addition, almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved.

The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations, could adversely affect our operations in the absence of any permits that may be required to regulate emission of GHGs, or could adversely affect demand for the crude oil and natural gas we gather, process, or otherwise handle. For instance, the EPA and BLM's recently proposed rules could result in the direct regulation of GHGs associated with our operations. We are not able at this time to estimate such increased costs; however, they could be significant. 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.

If new laws or regulations that significantly restrict GHGs are adopted, such laws could also make it more difficult or costly for our customers to operate, which could reduce our customers' production and therefore the demand for our services. 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. For instance, increasing regulatory pressures as a result of the EPA's "Clean Power Plan" rule or other initiatives could impact our customers' operations and, therefore, the overall demand for our services. Restrictions on GHG emissions could also reduce the volume of natural gas that our customers produce, and could thereby adversely affect our revenues and results of operations. 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 ultimately decrease end-user demand for our services and could have a material adverse effect on our business. In addition, to the extent financial markets view climate change and GHG 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 and crude oil products less desirable than competing sources of energy.

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

Substantial costs, liabilities, delays and other significant issues related to environmental laws and regulations are inherent in our crude oil transportation, natural gas transportation, storage and processing, NGL transportation and water business services, 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 and local laws, which impose obligations related to air emissions;
- CWA and analogous state and local laws, which regulate discharge of pollutants (Section 402) or fill material (Section 404) from our facilities to state and federal waters, including wetlands;
- CERCLA and analogous state and local 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 and local laws, which impose requirements for the handling and discharge of hazardous and nonhazardous solid waste from our facilities;

- OSHA and analogous state and local laws, 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;
- NEPA and analogous state and local laws, 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, and analogous state and local laws, 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;
- ESA and analogous state and local 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;
- Bald and Golden Eagle Protection Act and analogous state and local laws, which prohibits anyone, without a permit issued by the Secretary of the Interior, from "taking" bald or golden eagles, including their parts, nests, or eggs, and defines "take" as "pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb;"
- OPA and analogous state and local 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 and analogous state and local 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 and other similar laws and regulations and the permits and related plans issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these and other similar 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, process and store, air emissions related to our operations, historical industry operations, and waste disposal practices, such as the prior use of flow meters and manometers containing mercury. These activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment and the protection of plants, wildlife, and natural and cultural resources. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we handle or dispose of wastes or requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operators. 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 oil, natural gas and wastes on, under, or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. We are 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. We are currently conducting remediation at several sites to address contamination. For 2014, we spent approximately $270,000, for 2015 we spent approximately $497,000 and for 2016 we have budgeted approximately $1.3 million for these ongoing environmental remediation projects.

Private parties, including but not limited to the owners of properties through which our pipelines pass 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, processing, operations or other 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 June 2013, the EPA extended its National Enforcement Initiatives, enforcement priorities list, including an 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 products, including hydrocarbons and water, that we transport, store, gather, dispose and/or process could decline and our results of operations could be materially and 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, maintenance 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. For instance, on November 25, 2014, the Wyoming Department of Environmental Quality issued a Notice of Violation for violations of Part 60 Subpart OOOO related to the Casper Gas Plant Depropanizer project. TMID had discussed the issues in a meeting with WDEQ in Cheyenne on November 17, 2014 and submitted a disclosure on November 20, 2014 detailing the regulatory issues and potential violations. The project triggered a modification of the CAA's NSPS Subpart OOOO for the entire plant. The project equipment as well as plant equipment subjected to Subpart OOOO was not monitored timely, and initial notification was not made timely. Settlement negotiations with WDEQ are currently ongoing. Costs associated with penalties and to comply with the terms of any consent decree or settlement, as well as with Subpart OOOO, could be material.

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, such as our recent acquisition in December 2015 of a fresh water delivery and storage system, a produced water gathering and disposal system and multiple produced water disposal wells from Whiting, 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. As another example, 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 we have requested that the portion of the site attributable to us be delisted from the National Priorities List. As another example, in August 2011, the EPA and the Wyoming Department of Environmental Quality conducted an inspection of the Leak Detection and Repair Program, or LDAR, at the Casper Plant in Wyoming. In September 2011, TMID received a letter from the EPA alleging violations of the Standards of Performance of Equipment Leaks for Onshore Natural Gas Processing Plant requirements under the CAA. TMID received a letter from the EPA concerning settlement of this matter in April 2013 and received additional settlement communications from the EPA and Department of Justice beginning in July 2014. In July 2014, the EPA provided TMID with a draft Consent Decree that has been the basis for subsequent settlement negotiations. Subsequently, the EPA indicated that it intends to join TIGT as a defendant in this matter based on TIGT's ownership of the compressor station located adjacent to the Casper Gas Plant in order to address alleged LDAR issues at the compressor station. Most recently, the parties held a settlement meeting in August 2015. Following the settlement meeting, negotiations are continuing and the parties have entered into tolling agreements that have tolled the statute of limitations until April 29, 2016. We are not currently able to estimate the costs that may be associated with a settlement or other resolution of this matter, which could be substantial.

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.

Also, on June 29, 2015, the EPA and the U.S. Army Corps of Engineers, or Corps, issued a final rule to clarify the term "waters of the United States" as it pertains to federal jurisdiction under the CWA. Many interested parties believe that the rule expands federal jurisdiction under the CWA. Although it is unclear how the Corps and the EPA will implement this rule, the rule may require additional Corps or the EPA authorizations or involvement in our future operations, for instance, if we extend our pipelines into or across areas (such as certain ditches) newly considered "waters of the United States" under the final rule.

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 oil and natural gas processing operations could affect our operations and result in reductions or delays in production by our customers, which could have a material adverse impact on our revenues.

A sizeable portion of our customers' production comes from hydraulically fractured wells. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process typically involves the injection of water, sand and a small percentage of chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is regulated by state agencies, typically the state's oil and gas commission. A number of federal agencies, including the EPA and the U.S. Department of Energy, are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, on May 19, 2014, the EPA published an advance notice of rulemaking under the Toxic Substances Control Act, to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration and production. In August 2015, the EPA proposed updates to new source performance standard requirements that would impose more stringent controls on methane and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. The EPA has also issued a proposed rule that would prevent the discharge of hydraulic fracturing wastewater into publicly owned sewage treatment plants. Also, effective June 24, 2015, the BLM adopted rules regarding well stimulation, chemical disclosures, water management, and other requirements for hydraulic fracturing on federal and Indian lands. The BLM also proposed new rules in January 2016 to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases.

Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing entirely. Other governmental agencies, including the U.S. Department of Energy and the EPA, have evaluated or are evaluating various other aspects of hydraulic fracturing such as the potential environmental effects of hydraulic fracturing on drinking water and groundwater.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or significantly more costly for our customers to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing could also reduce the volume of crude oil, natural gas or other hydrocarbons that our customers produce, and could thereby adversely affect our revenues and results of operations. 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 ultimately decrease end-user demand for our services and could have a material adverse effect on our business.

Our produced water disposal operations may be subject to additional regulation and liability or claims of environmental damages.

We operate produced water disposal wells and locations, which have received the necessary governmental permits for drilling a disposal well. These wells are regulated under the federal SDWA as Class II wells and under state laws. State laws and regulations that govern these operations can be more stringent than the SDWA. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may also incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us. In addition, although the disposal wells have received certain governmental regulatory licenses, permits or approvals, this does not shield us from potential claims from third parties claiming contamination of their water supply or other environmental damages. Remediation of environmental contamination or damages can be extremely costly and such costs, if we are found liable, may have a material adverse effect on our business, financial condition and results of operations.

Produced water injection well operations and hydraulic fracturing may cause induced seismicity.

State and federal regulatory agencies recently have focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of produced water injection wells in the vicinity of seismic events have been ordered to reduce produced water injection volumes or suspend operations. Some state regulatory agencies, including those in Colorado and Texas, have modified their regulations to account for induced seismicity. Regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In 2015, the United States Geological Study identified eight states, including Colorado and Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In addition, a number of lawsuits have been filed, most recently in Oklahoma, alleging that produced water disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of produced water injection wells and hydraulic fracturing. Such regulations and restrictions could have a material adverse effect on our business, financial condition and results of operations.

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

A certain amount of natural gas and crude oil may be lost or unaccounted for in normal operations in connection with their transportation across a pipeline system. Under our tariffs and contractual arrangements with our customers we are entitled to retain a specified volume of natural gas and crude oil in order to compensate us for such lost and unaccounted for volumes, as well as the natural gas used to run our natural gas compressor stations, which we refer to collectively as fuel usage. Our pipeline tariffs, other than the Trailblazer Pipeline's, do not currently contain fuel usage true-up mechanisms. TIGT has proposed to replace its fixed FL&U charge with a FL&U tracker that would compensate TIGT for its actual FL&U expenses and adjust each year to reflect the previous period's under/over collection and the forecasted FL&U expense for the upcoming period. The FERC accepted such proposal to be effective upon motion May 1, 2016, subject to refund. The proposal may be ultimately rejected or modified by the FERC. The use of fuel (natural gas, electric and lost and unaccounted for gas) trackers on the Trailblazer Pipeline, while minimizing risk over time, nevertheless leaves the Trailblazer Pipeline exposed to the possibility of under- or over-collections on an annual basis. While the TIGT fuel tracker mirrors the Trailblazer tracker in requiring an annual redetermination, the TIGT proposal also allows for TIGT to re-determine the fuel reimbursement percentages and lost and unaccounted for ("L&U") reimbursement percentages on a monthly basis based on updated gas fuel and/or receipt quantities. This ability would act to further minimize TIGT's exposure to the possibility of under- or over-collections on an annual basis. The level of lost and unaccounted for volumes, and natural gas fuel usage, on our pipeline systems may exceed the natural gas and crude oil volumes retained from our customers as compensation for our lost and unaccounted for volumes, and fuel usage, pursuant to our tariffs and contractual agreements, and it may be necessary to purchase natural gas or crude oil in the market to make up for the difference, which exposes us to commodity price risk. Future exposure to the volatility of natural gas and crude oil prices as a result of lost and unaccounted for volume 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.

We have certain long-term fixed priced natural gas and crude oil transportation contracts that cannot be adjusted even if our costs increase, and we have certain crude oil transportation contracts that contain favored nation provisions that could require rate decreases if other similarly situated shippers are paying lower rates. As a result, our costs could exceed our revenues.

Approximately two-thirds of our contracted natural gas transportation firm capacity is provided under long-term, fixed price "negotiated or discount 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 or discount rate" contracts will exceed the negotiated or discounted rates. It is also possible with respect to discounted rates that if our filed "recourse rates" should ever be reduced below applicable discounted rates, we would only be allowed by the FERC to charge the lower recourse rates, since FERC policy does not allow discount rates to be charged to the extent that they exceed applicable recourse rates. If these events were to occur, it could decrease the cash flow realized by our assets 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 generally fixed between the natural gas pipeline and the shipper for the contract term and does not necessarily 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 accepted the negotiated rate agreement. These "negotiated or discount 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 or discounted rates, under current FERC policy, may be recoverable from other shippers in certain circumstances. For example, the FERC may recognize this shortfall in the determination of prospective rates in a future rate case. However, if the FERC were to disallow the recovery of such costs from other customers, it could decrease the cash flow realized by our assets and, therefore, the cash we have available for distributions to our unitholders.

Approximately 90% of the Pony Express System's current available capacity is provided to committed shippers under long-term "Throughput and Deficiency Agreements" or "TDAs". Rates under the TDAs are typically subject to change only per contract terms and conditions, including Pony Express's right to file changes to contract rates to reflect annual index percentage adjustments published by the FERC. We generally cannot file for rate increases with respect to committed shippers who have signed TDAs, other than to reflect annual index adjustments or to recover compliance costs imposed by governmental actions. Some of the TDAs also contain favored nations provisions which could result in lower rates being charged to certain committed shippers to ensure that the rates such shippers are paying are no greater than ninety to one hundred percent of the rates being charged to other similarly situated shippers for similar service at similar volumes and terms.

The TDAs for the Pony Express System and some of our service agreements with respect to our water business services contain provisions that can reduce the cash flow stability that the agreements were designed to achieve.

The TDAs for the Pony Express System and some of our service agreements with respect to our water services business are firm fee contracts with minimum volume commitments that are designed to generate stable cash flows and minimize direct commodity price risk. Under these minimum volume commitments, our customers agree to ship a minimum volume of crude oil or to have a minimum volume of water serviced, as the case may be, over certain periods during the term of the applicable agreement.

If a customer's actual throughput volumes or volumes serviced are less than its minimum volume commitment for the applicable period, it must make a deficiency payment at the end of the applicable period based upon the difference between the minimum volume commitment and the actual amounts serviced. A customer may apply any deficiency payments it makes as a credit against payment for volumes transported or serviced by us in excess of its minimum volume commitment in future periods. Upon termination of the Pony Express TDAs, customers may continue to use any remaining deficiency credits against any volumes serviced by us even though such customers may no longer have a minimum volume commitment.

To the extent that a customer's actual throughput volumes or volumes serviced are above its minimum volume commitment for the applicable period, the customer may use the excess volumes to credit against future deficiency payments in subsequent periods. Some or all of these provisions can apply in combination with one another. As a result, in the future we may not receive any cash payments for volumes shipped or serviced by us, and we may not receive deficiency payments as a result of excess volumes shipped in prior periods. This would result in reduced revenue and cash flows to us.

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

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

In addition to volatility and seasonality, an extended period of high natural gas prices would increase the cost of acquiring base gas and likely place upward pressure on the costs of associated storage expansion activities. Alternatively, an extended period of low seasonal volatility in 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.

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

Our revolving 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 revolving 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.

Further, our obligations under the revolving 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 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 our pipelines).

The provisions of our revolving 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 revolving 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 and we are unable to repay the debt in full, our lenders could foreclose on the assets pledged by us and the guarantors under the revolving credit facility. In that case, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

Tallgrass Equity’s ownership in our IDRs, our common units and our general partner interest, are pledged under Tallgrass Equity’s revolving credit facility.

Tallgrass Equity’s direct ownership of 20,000,000 of our common units and its direct ownership of our general partner (which owns our IDRs and general partner interest), are pledged as security under Tallgrass Equity’s revolving credit facility. Tallgrass Equity’s revolving credit facility contains customary and other events of default. Upon an event of default, the lenders under Tallgrass Equity’s revolving credit facility could foreclose on Tallgrass Equity's ownership interest in TEP GP and the 20,000,000 of our common units owned by Tallgrass Equity. This could ultimately result in a change in control of TEP GP, which would constitute an immediate event of default under our credit facility. This would have a material adverse effect on our business, financial condition and results of operations.

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 depends 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. Taking any of these actions is likely to reduce the value of your investment. Plus, 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.

The interest rate on borrowings under our revolving credit facility float based upon one or more of the prime rate, the U.S. federal funds rate or LIBOR. As a result, those borrowings, as well as borrowings under possible future credit facilities or debt offerings, could be higher than current levels, causing our financing costs to increase accordingly. We do not currently hedge the interest rate risk on borrowings under our revolving credit facility.

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

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

We rely on revenues generated from our assets, which are primarily located in the Rocky Mountain and Midwest regions of the United States. Revenues on our assets primarily depend on exploration and production activities of our customers located in these regions. Due to our lack of diversification in assets and geographic location, an adverse development in these businesses or our customers' areas of operations, including adverse developments due to catastrophic events, weather, regulatory action and decreases in supply or demand for hydrocarbons, 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. For example, our water business services is concentrated in a limited number of assets and primarily consists of our water business operations in Weld County, Colorado. Thus, the growth and profitability of our water business services will be especially vulnerable to conditions and fluctuations in the local Weld County economy and subject to changes in local government regulations and priorities.

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

We do not own in fee but rather have leases, easements, rights-of-way, permits and licenses for most of the land on which our assets are located, 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 interests in the land, if such interests in the land lapse or terminate or if our facilities are not properly located within the boundaries of such interests in the land. 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 our leases, easements, rights-of-way, permits and licenses, we might incur increased costs to maintain our assets, 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 leases, easements, rights-of-way, permits and licenses for our assets are shared with other pipeline systems and other assets owned by third parties. We or owners of the other pipeline systems or assets may not have commenced or concluded eminent domain proceedings for some rights-of-way. In some instances, lands over which leases, easements, rights-of-way, permits and licenses have been obtained are subject to prior liens which have not been subordinated to the grants to us.

Our interstate natural gas pipeline systems have federal eminent domain authority. Whether we have the power of eminent domain for the Pony Express crude oil pipeline varies from state to state, depending upon the laws of the particular state. 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 crude oil or natural gas pipeline systems are 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 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, 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 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, the transportation of crude oil and water, 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.

Upon the completion of our IPO, we became subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended. 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 requires 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. 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.

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.

New technology, including those involving recycling of produced water or the replacement of water in fracturing fluid, may adversely affect our future results of operations and financial condition.

The produced water disposal industry is subject to the introduction of new waste treatment and disposal techniques and services using new technologies including those involving recycling of produced water, some of which may be subject to patent protection. As competitors and others use or develop new technologies or technologies comparable to our water business services in the future, we may lose market share or be placed at a competitive disadvantage. For example, some companies have successfully used propane as the fracturing fluid instead of water. Further, we may face competitive pressure to implement or acquire certain new technologies at a substantial cost. Some of our competitors may have greater financial, technical and personnel resources than we do, which may allow them to gain technological advantages or implement new technologies before we can. Additionally, we may be unable to implement new technologies or products at all, on a timely basis or at an acceptable cost. New technology could also make it easier for our customers to vertically integrate their operations or reduce the amount of waste produced in oil and natural gas drilling and production activities, thereby reducing or eliminating the need for third-party disposal. Limits on our ability to effectively use or implement new technologies in our water business services may have a material adverse effect on our business, financial condition and results of operations.

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, service interruptions, 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, snowstorms and floods 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 Equity, TEGP and Tallgrass Energy Holdings, 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 Equity owns our general partner and appoints all of the officers and directors of our general partner. TEGP owns a 30.35% membership interest in, and is the managing member of, Tallgrass Equity. TEGP Management is TEGP's general partner. Tallgrass Energy Holdings is the sole member of TEGP Management and is also 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 Equity, TEGP Management and Tallgrass Energy 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 Energy 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 Equity. Conflicts of interest will arise between our general partner and its direct and indirect owners, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its direct and indirect 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 Energy Holdings, TEGP Management, Tallgrass Equity or their respective direct and indirect owners to pursue a business strategy that favors us, and the officers and directors of Tallgrass Energy Holdings, TEGP Management and Tallgrass Equity may have a fiduciary duty to make these decisions in the best interests of Tallgrass Energy Holdings, TEGP Management and Tallgrass Equity and their respective direct and indirect owners, respectively, which may be contrary to our interests. Tallgrass Energy Holdings, TEGP Management or Tallgrass Equity may choose to shift the focus of their investment and growth to areas not served by our assets.
- Tallgrass Energy Holdings, TEGP Management, Tallgrass Equity, their respective direct and indirect 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 TEP 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 Energy Holdings, its direct and indirect 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 Energy Holdings and will owe fiduciary duties to Tallgrass Energy Holdings and Tallgrass Development. Accordingly, these officers 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.
- 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 incentive distributions.
- 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 general partner units or to our general partner in respect of the IDRs.
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner may limit its liability regarding our contractual and other obligations.
- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.

- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us, including Tallgrass Development's and its affiliates' obligations under the TEP 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 Equity and its affiliates and Tallgrass Energy Holdings and its affiliates, 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 TEP 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.

Under our partnership agreement and the TEP Omnibus Agreement, we will reimburse our general partner and Tallgrass Energy Holdings 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 and the TEP Omnibus Agreement each provide 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 Energy Holdings 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 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 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 and Tallgrass Equity). Tallgrass Development and Tallgrass Equity currently own approximately 19.2% and 29.8% of our outstanding common units, respectively.

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

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

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

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

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces 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 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 last two 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 Equity, as a result of it owning our general partner, and not by our unitholders. Tallgrass Energy Holdings effectively controls our business and affairs through the exercise of its rights as the party that controls Tallgrass Equity. 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 units is required to remove our general partner. Tallgrass Development and Tallgrass Equity currently own approximately 19.2% and 29.8% of our outstanding common units, respectively. This gives our affiliates the ability to prevent the involuntary removal of our general partner. 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 and does not include most cases of charges of poor management of the business.

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 Energy Holdings to transfer all or a portion of its ownership interest in our general partner to a third party. For example, on May 12, 2015, Tallgrass Energy Holdings completed the initial public offering of TEGP that indirectly owns all of our incentive distribution rights, our general partner interest, and a certain number of our common units. Under this new structure, Tallgrass Energy Holdings continues to indirectly control our general partner, but, if, in the future, Tallgrass Energy Holdings no longer controls, directly or indirectly, our general partner, then a third party with a controlling interest in our general partner would 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.

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, including limited partner interests that rank senior to the common units, that 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 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.

Further, the recent downturn in the global capital markets has limited the availability of capital through traditional issuances of common units. It may be necessary for us to issue preferred units, convertible units, or other securities that rank senior to the common units in order to raise capital, which could further magnify the dilutive and other negative effects on unitholders' existing ownership interests.

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 hold 12,873,480 common units and Tallgrass Equity, which owns our general partner, currently holds 20,000,000 common units. 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 11 – *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 and Tallgrass Equity, each an affiliate of our general partner, currently own approximately 19.2% and 29.8% of our outstanding common units, respectively.

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. We have been paying quarterly cash distributions at the highest distribution level (48%) since our distribution with respect to the fourth quarter of 2014. Our general partner has the right to transfer the IDRs at any time, in whole or in part, and any transferee holding a majority of the IDRs shall have the same rights as our general partner with respect to resetting target distributions.

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

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

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

- we were conducting business in a state but had not complied with that particular state’s partnership statute; or
- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

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

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

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service treats us as a corporation for U.S. federal income tax purposes or we become subject to material additional amounts of entity-level taxation for state tax purposes, 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 in part on our being treated as a partnership for federal income tax purposes. We have not requested, and except as described below, 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 publicly traded partnership such as ours to be treated as a corporation rather than a partnership for U.S. federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, a change in our business or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. For example, we would be treated as a corporation if less than 90% of our gross income for any taxable year consists of "qualifying income" within the meaning of Section 7704 of the Internal Revenue Code.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. 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. Our 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 a 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.

At the state level, because of widespread state budget deficits, 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 a tax on us by any state will reduce the cash available for distributions to our unitholders.

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.

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, the President or 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, and the President proposed in his recently issued budget proposal to eliminate, 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.

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 even if no cash distributions are received 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, some, or all of any of such prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized on any sale or other disposition of your common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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 generally 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 recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015, such regulations 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 have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of 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 and its direct and indirect owners own a substantial interest in our capital and profits. Therefore, a transfer by them of all or a portion of their 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 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 tax payments, as well as interest and penalties.

We have a subsidiary that is treated as a corporation for federal income tax purposes and subject to corporate level income taxes and may conduct additional activities in taxable corporate subsidiaries in the future.

Even though we (as a partnership for U.S. federal income tax purposes) are not subject to U.S. federal income tax, we have a subsidiary that is organized as a corporation for U.S. federal income tax purposes. Although this subsidiary has not previously generated any material income, we may elect to conduct additional activities in one or more subsidiaries treated as corporations for U.S. federal income tax purposes in the future that could generate material income. For example, it is unclear whether and to what extent our share of water business services income from Water Solutions will be treated as qualifying income. The IRS recently issued proposed regulations providing that income from water delivery services is not qualifying income unless the partnership providing those services also collects, and cleans, recycles or otherwise disposes of the water after use in accordance with applicable law. While we have not requested a ruling from the IRS that income from Water Solutions, or a portion of such income, is qualifying income, we may request such a ruling in the future. If the treatment of water services income in the proposed regulations is adopted as final regulations or if the IRS is unwilling or unable to provide a favorable ruling in a timely manner, and if it becomes necessary in order to preserve our status as a partnership, we may elect to conduct all or portions of our Water Solutions business in a taxable corporate subsidiary (see *"Risk Factors - 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 taxable income, if any, of a subsidiary that is treated as a corporation for U.S. federal income tax purposes, is subject to corporate-level U.S. federal income taxes, which may reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS or other state or local jurisdictions were to successfully assert that this corporation has more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, the cash available for distribution could be further reduced. The income tax return filing positions taken by corporate subsidiaries could require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment could also be required in assessing the timing and amounts of deductible and taxable items. Despite our belief that the income tax return positions taken by our corporate subsidiaries would be fully supportable, certain positions may be successfully challenged by the IRS, state or local jurisdictions.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to (or will choose to) do so under all circumstances. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced.

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 4200 W. 115th Street, Suite 350, Leawood, KS 66211 and our telephone number is 913-928-6060.

We own two office buildings in Lakewood, Colorado, with a portion being leased to a third party pursuant to a lease with an initial term through 2020. In addition, we lease our principal executive offices in Leawood, Kansas. Tallgrass Development pays a proportionate share of the costs to occupy the building to us pursuant to the TEP Omnibus Agreement.

Item 3. Legal Proceedings

See Note 17 – *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.

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, as reported by the NYSE, as well as the amount of cash distributions per unit declared for the periods indicated:

Quarter Ended	High	Low	Distribution per Common Unit
December 31, 2015	$ 47.63	$ 33.40	$ 0.6400
September 30, 2015	49.09	35.02	0.6000
June 30, 2015	52.13	47.21	0.5800
March 31, 2015	53.70	40.00	0.5200
December 31, 2014	45.49	33.83	0.4850
September 30, 2014	47.04	37.90	0.4100
June 30, 2014	40.22	34.50	0.3800
March 31, 2014	36.49	25.25	0.3250
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 February 17, 2016, there were 63 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 February 17, 2016, our general partner owned all 834,391 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 distributions 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.

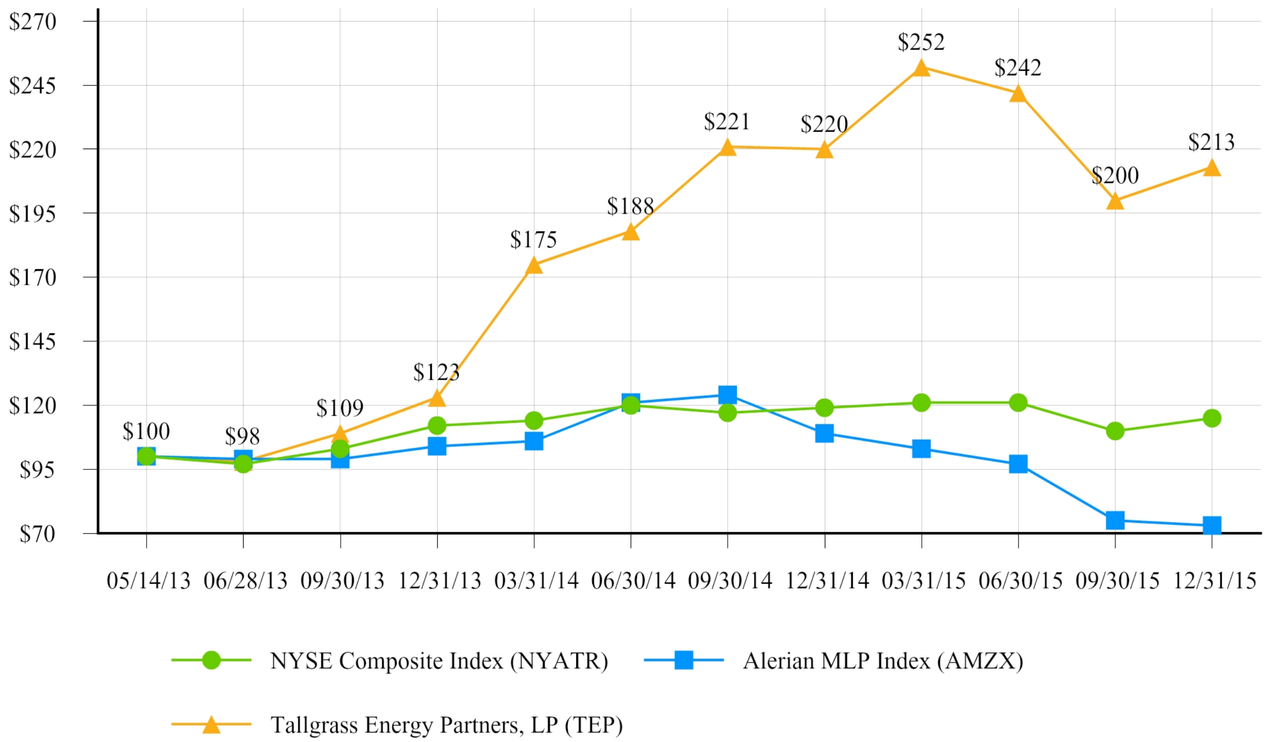
General Partner Interest. Our general partner is currently entitled to approximately 1.23% of all quarterly distributions that we make prior to our liquidation based on its ownership of the general partner interest. As of February 17, 2016 our general partner interest is represented by 834,391 general partner units. Our general partner has the right, but not the obligation, to contribute a proportional amount of capital to us to maintain its general partner interest, up to 2%. The general partner's proportionate interest in our quarterly 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 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. Such higher target distribution levels have been achieved and we have been distributing 48% on the IDRs since our distribution with respect to the fourth quarter of 2014. For additional information, see Note 11 – *Partnership Equity and Distributions* to our Consolidated Financial Statements in Item 8.—Financial Statements and Supplementary Data in this Form 10-K.

Conversion of Subordinated Units. Under the terms of our partnership agreement and upon the payment of our quarterly cash distribution to unitholders on February 13, 2015, our subordination period ended. As a result, our 16,200,000 subordinated units held by TD converted into common units on a one for one basis on February 17, 2015. The conversion of the subordinated units did not impact the aggregate amount of cash distributions paid.

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, 2015. 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.



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 TIGT and TMID, which we refer to collectively as "our Predecessor." As discussed further in Note 2 – Summary of Significant Accounting Policies to the accompanying consolidated financial statements, the financial statements of our Predecessor for historical periods beginning after November 13, 2012 have been recast to reflect the operations of Trailblazer, which was acquired on April 1, 2014, and Pony Express, of which TEP acquired a controlling 33.3% membership interest effective September 1, 2014.

In connection with our initial public offering on May 17, 2013, TD contributed to us its equity interests in our Predecessor. The term "TEP Pre-Predecessor" refers to the Tallgrass Energy Partners Pre-Predecessor, which represents the combined results of operations of TIGT and TMID 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. Financial information for the TEP Pre-Predecessor has not been recast to reflect the operations of Trailblazer and Pony Express. The following discussion analyzes the financial condition and results of operations of our Predecessor. In certain circumstances and for ease of reading we discuss the financial results of the Predecessor as being "our" financial results during historic periods, although TIGT and TMID were owned by TD from November 13, 2012 until May 17, 2013, Trailblazer was owned by TD from November 13, 2012 to March 31, 2014, and Pony Express was wholly-owned by TD from November 13, 2012 to August 31, 2014. 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 following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and related notes thereto included elsewhere in this Annual Report. A reference to a "Note" herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8.—Financial Statements. In addition, please read "Cautionary Statement Regarding Forward-Looking Statements" and "Risk Factors" for information regarding certain risks inherent in our business.

The following table shows selected historical financial and operating data of TEP for the periods and as of the dates indicated. The selected historical financial data for the period from November 13, 2012 to December 31, 2012 and the years ended December 31, 2014 and 2013 are derived from the audited financial statements of TEP as recast for the acquisitions of Trailblazer and our initial 33.3% membership interest in Pony Express.

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.

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 condition 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,			Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	2015	2014	2013			
	(in thousands, except per unit amounts)				(in thousands, except per unit amounts)	
Statement of operations data:						
Revenue	$ 536,197	$ 371,556	$ 290,526	$ 38,572	$ 220,292	$ 307,043
Operating income	$ 197,915	$ 53,413	$ 33,999	$ 69	$ 50,113	$ 75,499
Net income (loss)	$ 184,814	$ 59,329	$ 7,624	$ (2,618)	$ 51,496	$ 77,507
Net income (loss) attributable to partners	$ 160,546	$ 70,681	$ 9,747	$ (2,366)	$ 51,496	$ 77,507
Net income allocable to limited partners	$ 114,068	$ 61,774	$ 6,991 (1)	N/A	N/A	N/A
Net income per limited partner unit - basic	$ 1.95	$ 1.39	$ 0.17 (1)	N/A	N/A	N/A
Net income per limited partner unit - diluted	$ 1.91	$ 1.36	$ 0.17 (1)	N/A	N/A	N/A
Balance sheet data (at end of period):						
Property, plant and equipment, net	$ 2,025,018	$ 1,853,081	$ 1,116,806	$ 726,754	$ 717,486	$ 719,009
Total assets	$ 2,562,074	$ 2,457,197	$ 1,631,413	$ 1,238,598	$ 767,681	$ 772,896
Long-term debt	$ 753,000	$ 559,000	$ 135,000	$ —	$ —	$ —
Long-term debt allocated from TD	$ —	$ —	$ —	$ 390,491	$ —	$ —
Other:						
Distributions declared per common unit	$ 2.3400	$ 1.6000	$ 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

Historical periods have been recast to reflect the operations of Trailblazer, which was acquired on April 1, 2014, and Pony Express, of which TEP acquired a controlling 33.3% membership interest effective September 1, 2014. TEP's subsequent acquisition of an additional 33.3% membership interest in Pony Express on March 1, 2015 represents an acquisition of noncontrolling interests. As a result, financial information for periods prior to that transaction have not been recast to reflect the additional 33.3% membership interest. In certain circumstances and for ease of reading we discuss the financial results of these entities prior to their respective acquisitions as being "our" financial results during historic periods, although Trailblazer was owned by TD from November 13, 2012 to March 31, 2014, and Pony Express was wholly-owned by TD from November 13, 2012 to August 31, 2014.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and related notes thereto included elsewhere in this Annual Report.

Overview

We are a publicly traded, growth-oriented limited partnership formed to own, operate, acquire and develop midstream energy assets in North America. We currently provide crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through Pony Express, which owns the Pony Express System, a crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma that includes a lateral in Northeast Colorado that commences in Weld County, Colorado, and interconnects with the pipeline just east of Sterling, Colorado. 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, a FERC-regulated natural gas transportation and storage system located in Colorado, Kansas, Missouri, Nebraska and Wyoming, and the Trailblazer Pipeline, a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Nebraska. We also provide services for customers at our Midstream Facilities located in Wyoming, and NGL transportation services in Northeast Colorado. We perform water business services in Colorado and Texas through Water Solutions. Our operations are strategically located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg, Powder River, Wind River, Permian and Hugoton-Anadarko Basins and the Niobrara, Mississippi Lime, Eagle Ford and Bakken shale formations.

We intend to continue 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:

- Crude Oil Transportation & Logistics—the ownership and operation of a crude oil pipeline system;
- Natural Gas Transportation & Logistics—the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities; and
- Processing & Logistics—the ownership and operation of natural gas processing, treating and fractionation facilities, the provision of water business services primarily to the oil and gas exploration and production industry and the transportation of NGLs.

Summary of Results for the Year Ended December 31, 2015

During 2015, we completed a follow-on public offering of 11,200,000 common units and the acquisitions of an additional 33.3% membership interest in Pony Express and a 100% membership interest in Western, which owns water business services assets located in Weld County, Colorado. In addition, Pony Express placed into commercial service its lateral in Northeast Colorado during the second quarter of 2015.

Net income attributable to partners for the year ended December 31, 2015 was $160.5 million, with Adjusted EBITDA and Distributable Cash Flow (each as defined below under "*Non-GAAP Financial Measures*") of $252.3 million and $220.5 million, respectively, compared to net income attributable to partners for the year ended December 31, 2014 of $70.7 million, with Adjusted EBITDA and Distributable Cash Flow of $109.9 million and $96.1 million, respectively. The increase in net income, Adjusted EBITDA, and Distributable Cash Flow was largely driven by the ramping up of commercial operations at Pony Express and the lateral in Northeast Colorado and our acquisition of an additional 33.3% membership interest in Pony Express on March 1, 2015, as discussed further under "Results of Operations" below.

Recent Developments

Distribution Declared

On January 4, 2016, the Board of Directors of our general partner declared a cash distribution for the quarter ended December 31, 2015 of $0.64 per common unit. The distribution was paid on February 12, 2016, to unitholders of record on January 29, 2016.

Acquisition of an Additional 31.3% of Pony Express

Effective January 1, 2016, TEP acquired an additional 31.3% membership interest in Pony Express in exchange for cash consideration of $475 million and 6,518,000 TEP common units (valued at approximately $268.6 million based on the December 31, 2015 closing price of TEP's common units) issued to TD for total consideration of approximately $743.6 million. The transaction increases TEP's aggregate membership interest in Pony Express to 98.0%. As part of the transaction, TD granted TEP an 18 month call option to repurchase the newly issued 6,518,000 common units at a price of $42.50.

Revolving Credit Facility

In connection with the acquisition of an additional 31.3% membership interest in Pony Express as discussed above, TEP exercised its option to increase the commitment under its existing revolving credit facility from $1.1 billion to $1.5 billion effective January 4, 2016. As of January 31, 2016, TEP had approximately $1.2 billion of outstanding borrowings under its revolving credit facility.

Tallgrass Development Purchase Program

On February 17, 2016, TEP and TEGP announced that the Board of Directors of Tallgrass Energy Holdings, the sole member of TEGP's general partner and the general partner of TD, has authorized an equity purchase program under which TD may initially purchase up to an aggregate of $100 million of the outstanding Class A shares of TEGP or the outstanding common units of TEP. TD may purchase Class A shares or Common Units from time to time on the open market or in negotiated purchases. The timing and amounts of any such purchases will be subject to market conditions and other factors, and will be in accordance with applicable securities laws and other legal requirements. The purchase plan does not obligate TD to acquire any specific number of Class A shares or Common Units and may be discontinued at any time.

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.

Long Term U.S. Crude Oil and Natural Gas Prospects

Crude oil, natural gas and products derived from both continue to be critical components of energy supply and demand in the United States. Although crude oil and natural gas prices have declined significantly in the latter part of 2014 and throughout 2015 and early 2016, and may experience further declines or remain at or near current levels for the foreseeable future, we nevertheless believe that the long-term prospects for continued crude oil and natural gas production increases are favorable.

We believe long-term growth will be driven, in part, by a combination of increased domestic demand resulting from population and economic growth, higher industrial consumption in the U.S., and a desire to reduce domestic reliance on imports. One example is that we expect natural gas to gradually displace coal-fired electricity generation due to the low prices of natural gas and stricter environmental regulations on the mining and burning of coal. We expect productivity of oil and natural gas wells to continue increasing over the long-term in some basins across the United States because of the increasing precision and efficiency of horizontal drilling and hydraulic fracturing in oil and natural gas extraction. We also believe there is a substantial inventory of drilled but uncompleted wells in the basins we serve, including the Bakken shale, that is likely to be completed and turned into production once commodity prices recover and volatility decreases.

Current Commodity Environment

Starting in 2014, the prices of crude oil, natural gas, and NGLs were extremely volatile and declined significantly. Downward pressure on commodity prices continued in 2015 and the early part of 2016 and may continue for the foreseeable future. This could impact our business in several ways.

Demand for our services depends, in part, on the development of additional natural gas and crude oil reserves by third parties. This requires significant capital expenditures by others to install facilities that extract natural gas and crude oil. However, low commodity prices result in a lack of available capital for these types of expenditures. To the extent our customers cannot finance these activities, we also expect they will be less likely to enter into demand based, long-term firm fee contracts until commodity prices recover and pricing stability returns to the commodity markets. The recent commodity price declines may also negatively impact the financial condition of our customers and could impact their ability to meet their financial obligations to us.

Additionally, lower commodity prices generally lead to reduced utilization of our assets. For example, reduced utilization could result in increased deficiency balances held by customers of our Pony Express System. For additional information, see *"Risk Factors - The TDAs for the Pony Express System and some of our service agreements with respect to our water business services contain provisions that can reduce the cash flow stability that the agreements were designed to achieve."* In addition, declining drilling activity by producers and other factors within the region served by our Midstream Facilities has led to an average quarterly decrease in our natural gas processing inlet volumes at our natural gas processing and treating plants of 11% over the year ended December 31, 2015. We expect further volumetric decreases in 2016. As a result, management identified a potential impairment trigger with respect to the goodwill allocated to the TMID reporting unit. As discussed further under "Critical Accounting Policies and Estimates" below, we tested the goodwill for impairment as of December 31, 2015 and noted that no impairment exists at this time.

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 and expect to continue to acquire assets from TD's portfolio of midstream assets, which include TD's 50% interest in, and operation of, the REX Pipeline, and 100% ownership interest in Terminals. We expect TD to retain its 2% ownership interest in Pony Express for the foreseeable future. Pursuant to the TEP 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. Terminals is not a Retained Asset. Other than its obligations under the TEP Omnibus Agreement, TD is 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 its 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.

Growth associated with expansion projects

We also believe that we are well positioned to increase volumes to our systems through cost-effective capacity expansions and other methods for improving efficiency, such as the use of drag reducing agents in our crude oil pipelines. For example, in 2014, Pony Express completed the conversion and construction of its approximately 698-mile crude oil pipeline commencing in Guernsey, Wyoming, and terminating in Cushing, Oklahoma. In 2015, Pony Express completed the construction of an approximately 66-mile lateral in Northeast Colorado commencing in Weld County, Colorado, and interconnecting with the pipeline just east of Sterling, Colorado.

Energy Capital Markets and Interest Rates

During the second half of 2015 the energy credit markets experienced a material increase in the yields for long term debt, causing an issuance of senior unsecured notes to be a less attractive financing option. At the same time, the downturn in commodity prices has also generally limited the availability of capital through traditional public issuances of common units. While this downturn has not changed our business plans, including our continued intent to grow through acquisitions and expansion projects, it has altered some of our financing strategies.

In addition, the Federal Reserve increased short-term interest rates which marginally impacted the rates on our floating rate revolving credit facility. If the economy continues to strengthen, it is likely that monetary policy will continue to tighten, resulting in higher interest rates to counter possible inflation. If this occurs, interest rates on our floating rate credit facilities and future offerings in the debt capital markets could be at higher rates, causing our financing costs to increase accordingly. For additional information, please read Item 7A.—Quantitative and Qualitative Disclosures About Market Risk.

How We Evaluate Our Operations

We evaluate our results using, among other measures, contract profile 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 Profile and Volumes

Our results are driven primarily by the volume of crude oil transportation capacity, natural gas transportation and storage capacity, NGL transportation capacity, and water transportation, gathering and disposal capacity under firm contracts, as well as 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, cost of 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, nor should Adjusted EBITDA and Distributable Cash Flow be considered alternatives to available cash, operating surplus, distributions of available cash from operating surplus or other definitions in our partnership agreement. 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 generally define Adjusted EBITDA as net income excluding the impact of 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 or business disposals or acquisitions, gains or losses on the repurchase, redemption or early retirement of debt, and earnings from unconsolidated investments, but including the impact of distributions from unconsolidated investments. We also use Distributable Cash Flow, which we generally define as Adjusted EBITDA, plus preferred distributions received from Pony Express in excess of its distributable cash flow attributable to our net interest and adjusted for deficiency payments received from or utilized by Pony Express shippers, less cash interest expense, maintenance capital expenditures, distributions to noncontrolling interests in excess of earnings allocated to noncontrolling interests, and cash reserves permitted by our partnership agreement, to analyze our performance. Maintenance capital expenditures are cash expenditures incurred (including expenditures for the construction or development of new capital assets) that we expect to maintain our long-term operating income or operating capacity. These expenditures typically include certain system integrity, compliance and safety improvements.

TEP received a minimum quarterly preference payment from Pony Express of $36.65 million through the quarter ended December 31, 2015 (prorated to approximately $23.5 million for the quarter ended March 31, 2015). To the extent that Pony Express did not have sufficient Distributable Cash Flow to cover this preference payment, TD, as the noncontrolling interest owner, was required to contribute cash to Pony Express to fund the excess preference payment. The cash received by Pony Express from TD to fund the minimum quarterly preference payment in excess of distributable cash flow from Pony Express was considered Distributable Cash Flow at TEP. Effective January 1, 2016, TEP no longer receives a minimum quarterly preference payment from Pony Express. Pony Express collects deficiency payments for barrels committed by the customer to be transported in a month but not physically received for transport or delivered to the customers' agreed upon destination point. These deficiency payments are recorded as a deferred liability until the barrels are physically transported and delivered by TEP. As discussed further in Note 2 – *Summary of Significant Accounting Policies*, earnings at Pony Express are allocated between TEP and noncontrolling interests in accordance with a substantive profit sharing arrangement rather than pro rata by ownership. Distributions made by Pony Express to its noncontrolling interests reduce the Distributable Cash Flow available to TEP.

Distributable Cash Flow and Adjusted EBITDA are not presentations made in accordance with GAAP. 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:

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Reconciliation of Adjusted EBITDA to Net Income			
Net income attributable to partners	$ 160,546	$ 70,681	$ 9,747
Add:			
Interest expense, net of noncontrolling interest	15,517	7,648	11,035
Depreciation and amortization expense, net of noncontrolling interest	75,529	45,389	37,898
Loss on extinguishment of debt	226	—	17,526
Non-cash (gain) loss related to derivative instruments	—	(184)	386
Non-cash compensation expense	5,103	5,136	1,798
Non-cash loss from asset sales	4,795	—	—
Distributions from unconsolidated investment	—	1,464	—
Less:			
Non-cash loss allocated to noncontrolling interest	(9,377)	(10,151)	—
Gain on remeasurement of unconsolidated investment	—	(9,388)	—
Equity in earnings of unconsolidated investment	—	(717)	—
Adjusted EBITDA	**$ 252,339**	**$ 109,878**	**$ 78,390**
Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Cash Provided by Operating Activities			
Net cash provided by operating activities	$ 289,296	$ 79,444	$ 82,482
Add:			
Interest expense, net of noncontrolling interest	15,517	7,648	11,035
Other, including changes in operating working capital	(52,474)	22,786	(15,127)
Adjusted EBITDA	**$ 252,339**	**$ 109,878**	**$ 78,390**
Add:			
Pony Express preferred distributions in excess of distributable cash flow attributable to Pony Express	—	5,429	—
Pony Express deficiency payments received, net	16,511	5,378	—
Less:			
Cash interest cost	(13,746)	(6,266)	(3,555)
Maintenance capital expenditures	(12,123)	(9,913)	(15,951)
Distributions to noncontrolling interest in excess of earnings	(22,479)	(5,361)	—
Cash flow attributable to predecessor operations	—	(3,086)	3,367
Distributable Cash Flow	**$ 220,502**	**$ 96,059**	**$ 62,251**

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:

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Reconciliation of Adjusted EBITDA to Operating Income in the Crude Oil Transportation & Logistics Segment [(1)]			
Operating income (loss)	$ 159,467	$ 3,601	$ (3,156)
Add:			
Depreciation and amortization expense, net of noncontrolling interest	39,359	10,553	1,009
Adjusted EBITDA attributable to noncontrolling interests	(24,245)	11,708	2,104
Less:			
Non-cash loss allocated to noncontrolling interest	(9,377)	(10,151)	—
Segment Adjusted EBITDA	**$ 165,204**	**$ 15,711**	**$ (43)**
Reconciliation of Adjusted EBITDA to Operating Income in the Natural Gas Transportation & Logistics Segment [(1)]			
Operating income	$ 41,802	$ 40,887	$ 24,040
Add:			
Depreciation and amortization expense	22,927	23,788	30,169
Non-cash (gain) loss related to derivative instruments	—	(184)	386
Other income	2,639	3,102	2,226
Segment Adjusted EBITDA	**$ 67,368**	**$ 67,593**	**$ 56,821**
Reconciliation of Adjusted EBITDA to Operating Income in the Processing & Logistics Segment [(1)]			
Operating income	$ 4,728	$ 20,577	$ 16,472
Add:			
Depreciation and amortization expense, net of noncontrolling interest	13,243	11,048	6,720
Non-cash loss from asset sales	4,795	—	—
Distributions from unconsolidated investment	—	1,464	—
Adjusted EBITDA attributable to noncontrolling interests	(20)	—	—
Segment Adjusted EBITDA	**$ 22,746**	**$ 33,089**	**$ 23,192**
Total Segment Adjusted EBITDA	**$ 255,318**	**$ 116,393**	**$ 79,970**
Corporate general and administrative costs	(2,979)	(2,500)	(1,580)
Elimination of intersegment activity	—	(4,015)	—
Total Adjusted EBITDA	**$ 252,339**	**$ 109,878**	**$ 78,390**

(1) Segment results as presented represent total operating income and Adjusted EBITDA, including intersegment activity, for the Crude Oil Transportation & Logistics, Natural Gas Transportation & Logistics, and Processing & Logistics segments. For reconciliations to the consolidated financial data, see Note 18 – *Reporting Segments* to the accompanying consolidated financial statements.

Results of Operations

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

	Year Ended December 31,		
	2015	2014	2013
	(in thousands, except operating data)		
Revenues:			
Crude oil transportation services	$ 300,436	$ 28,343	$ —
Natural gas transportation services	119,895	126,733	120,025
Sales of natural gas, NGLs, and crude oil	82,133	181,249	155,700
Processing and other revenues	33,733	35,231	14,801
Total Revenues	536,197	371,556	290,526
Operating Costs and Expenses:			
Cost of sales (exclusive of depreciation and amortization shown below)	75,285	167,545	131,095
Cost of transportation services (exclusive of depreciation and amortization shown below)	53,597	24,109	15,059
Operations and maintenance	49,138	39,577	35,404
Depreciation and amortization	83,476	47,048	39,917
General and administrative	50,195	33,160	27,651
Taxes, other than income taxes	21,796	6,704	7,401
Loss on sale of assets	4,795	—	—
Total Operating Costs and Expenses	338,282	318,143	256,527
Operating Income	197,915	53,413	33,999
Other (Expense) Income:			
Interest expense, net	(15,514)	(7,292)	(11,054)
Gain on remeasurement of unconsolidated investment	—	9,388	—
Loss on extinguishment of debt	(226)	—	(17,526)
Equity in earnings of unconsolidated investment	—	717	—
Other income, net	2,639	3,103	2,205
Total Other (Expense) Income	(13,101)	5,916	(26,375)
Net income	184,814	59,329	7,624
Net (income) loss attributable to noncontrolling interests	(24,268)	11,352	2,123
Net income attributable to partners	160,546	70,681	9,747
Other Financial Data [1]			
Adjusted EBITDA	$ 252,339	$ 109,878	$ 78,390
Operating Data:			
Crude oil transportation average throughput (Bbls/d) [2]	236,256	85,229	N/A
Gas transportation firm contracted capacity (MMcf/d)	1,517	1,537	1,411
Natural gas processing inlet volumes (MMcf/d)	122	152	133

(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.

(2) Approximate average daily throughput for the year ended December 31, 2014 is reflective of the volumetric ramp up due to commercial in-service of the Pony Express System beginning in October 2014, including the lateral in Northeast Colorado in the second quarter of 2015, and delays in the construction and expansion efforts of third-party pipelines with which Pony Express shares joint tariffs.

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Revenues. Total revenues were $536.2 million for the year ended December 31, 2015, compared to $371.6 million for the year ended December 31, 2014, which represents an increase of $164.6 million, or 44%, in total revenues. The overall increase in revenues was primarily driven by increased revenue of $275.9 million in the Crude Oil Transportation & Logistics segment, partially offset by decreases in revenues of $102.7 million and $8.4 million in the Processing & Logistics and Natural Gas Transportation & Logistics segments, respectively, as discussed further below.

Operating costs and expenses. Operating costs and expenses were $338.3 million for the year ended December 31, 2015 compared to $318.1 million for the year ended December 31, 2014, which represents an increase of $20.1 million, or 6%. The overall increase in operating costs and expenses is primarily driven by increased operating costs and expenses of $120.0 million in the Crude Oil Transportation & Logistics segment, partially offset by decreases in operating costs and expenses of $86.8 million and $9.3 million in the Processing & Logistics and Natural Gas Transportation & Logistics segments, respectively, as discussed further below.

Interest expense, net. Interest expense of $15.5 million for the year ended December 31, 2015 was primarily composed of interest and fees associated with TEP’s revolving credit facility, partially offset by interest income of $0.4 million on the cash balance swept to TD under the Pony Express cash management agreement. Interest expense of $7.3 million for the year ended December 31, 2014 was primarily composed of interest and fees associated with TEP’s revolving credit facility, partially offset by interest income of $1.5 million on the cash balance swept to TD under the Pony Express cash management agreement. The increase in interest and fees associated with TEP's revolving credit facility in 2015 was driven by increased borrowings throughout 2014 and 2015 to fund the acquisitions of Trailblazer and our 66.7% membership interest in Pony Express.

Gain on remeasurement of unconsolidated investment. Gain on remeasurement of unconsolidated investment of $9.4 million for the year ended December 31, 2014 was related to the remeasurement to fair value of our original 50% equity investment in Grasslands Water Services I, LLC ("GWSI") in connection with TEP's consolidation of the Water Solutions business on May 13, 2014.

Loss on extinguishment of debt. Loss on extinguishment of debt of $0.2 million for the year ended December 31, 2015 represents the loss associated with the write off of deferred financing costs associated with the reassignment of a single lender's commitment under our revolving credit facility.

Equity in earnings of unconsolidated investment. Equity in earnings of unconsolidated investment of $0.7 million for the year ended December 31, 2014 was related to our investment in GWSI prior to TEP's consolidation of the Water Solutions business on May 13, 2014.

Other income, net. Other income, net typically includes rental income, income earned from certain customers related to the capital costs we incurred to connect these customers to our system, and the allowance for funds used during construction at our regulated entities. Other income for the year ended December 31, 2015 was $2.6 million compared to $3.1 million for the year ended December 31, 2014.

Net (income) loss attributable to noncontrolling interests. Net income attributable to noncontrolling interests of $24.3 million for the year ended December 31, 2015 primarily reflects the net income allocated to TD's 66.7% noncontrolling interest in Pony Express for the period from January 1, 2015 to February 28, 2015 and TD's 33.3% noncontrolling interest for the period from March 1, 2015 to December 31, 2015. Net loss attributable to noncontrolling interest of $11.4 million for the year ended December 31, 2014 primarily reflects TD's 66.7% noncontrolling interest in Pony Express.

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Revenues. Total revenues were $371.6 million for the year ended December 31, 2014, compared to $290.5 million for the year ended December 31, 2013, which represents an increase of $81.0 million, or 28%, in total revenues. The overall increase in revenues is primarily driven by increased revenues of $43.8 million in the Processing & Logistics segment and $12.2 million in the Natural Gas Transportation & Logistics segment. Additionally, there were revenues of $28.3 million in the Crude Oil Transportation & Logistics segment for the year ended December 31, 2014, but no revenues in that segment for the year ended December 31, 2013 as Pony Express had not yet commenced commercial operations.

Operating costs and expenses. Operating costs and expenses were $318.1 million for the year ended December 31, 2014 compared to $256.5 million for the year ended December 31, 2013, which represents an increase of $61.6 million, or 24%. The overall increase in operating costs and expenses is primarily driven by increased operating costs and expenses of $39.7 million in the Processing & Logistics segment and increased operating costs and expenses of $21.6 million in the Crude Oil & Logistics segment due to the start of commercial operations at the mainline portion of the Pony Express System in October 2014. The increased costs in the Processing & Logistics and Crude Oil & Logistics segments were partially offset by decreased costs of $4.6 million in the Natural Gas Transportation & Logistics segment.

Interest expense, net. Interest expense of $7.3 million for the year ended December 31, 2014 was primarily composed of interest and fees associated with TEP's revolving credit facility, partially offset by interest income of $1.5 million on the cash balance swept to TD under the Pony Express cash management agreement. Interest expense of $11.1 million for the year ended December 31, 2013 primarily 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, as well as interest and fees associated with TEP's revolving credit facility.

Gain on remeasurement of unconsolidated investment. Gain on remeasurement of unconsolidated investment of $9.4 million for the year ended December 31, 2014 was related to the remeasurement to fair value of our original 50% equity investment in Grasslands Water Services I, LLC ("GWSI") in connection with TEP's consolidation of the Water Solutions business on May 13, 2014.

Loss on extinguishment of debt. Loss on extinguishment of debt of $17.5 million for 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.

Equity in earnings of unconsolidated investment. Equity in earnings of unconsolidated investment of $0.7 million for the year ended December 31, 2014 was related to our investment in GWSI prior to TEP's consolidation of the Water Solutions business on May 13, 2014.

Other income, net. Other income, net typically includes rental income, income earned from certain customers related to the capital costs we incurred to connect these customers to our system, and the allowance for funds used during construction at our regulated entities. Other income for the year ended December 31, 2014 was $3.1 million compared to $2.2 million for the year ended December 31, 2013.

Net (income) loss attributable to noncontrolling interests. Net loss attributable to noncontrolling interests of $11.4 million for the year ended December 31, 2014 primarily reflects TD's 66.7% noncontrolling interest of Pony Express. Net loss attributable to noncontrolling interest of $2.1 million for the year ended December 31, 2013 primarily reflects TD's 66.7% noncontrolling interest in the amortization of oil conversion use rights at Pony Express prior to commencement of commercial operations.

The following provides a summary of our Crude Oil Transportation & Logistics segment results of operations for the periods indicated:

Segment Financial Data - Crude Oil Transportation & Logistics [(1)]	Year Ended December 31, 2015	2014	2013
	(in thousands)		
Revenues:			
Crude Oil transportation services	$ 300,436	$ 28,343	$ —
Sales of natural gas, NGLs, and crude oil	3,791	—	—
Total revenues	304,227	28,343	—
Operating costs and expenses:			
Cost of sales	4,257	—	—
Cost of transportation services	47,367	7,025	—
Operations and maintenance	8,795	717	—
Depreciation and amortization	47,168	12,067	3,028
General and administrative	20,620	4,683	128
Taxes, other than income taxes	16,553	250	—
Total operating costs and expenses	144,760	24,742	3,156
Operating income (loss)	$ 159,467	$ 3,601	$ (3,156)

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 18 – *Reporting Segments* to the accompanying consolidated financial statements.

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Revenues. Crude Oil Transportation & Logistics segment revenues were $304.2 million for the year ended December 31, 2015, compared to $28.3 million for the year ended December 31, 2014. Revenue for the year ended December 31, 2015 represents a full year of operations at Pony Express, including approximately $62.6 million of revenue from a partial year of operations on the lateral in Northeast Colorado, which began commercial operations during the second quarter of 2015, and approximately $32.8 million related to the activation of one of our joint tariffs in the second quarter of 2015. Revenue for the year ended December 31, 2014 represents a partial year of operations at the mainline portion of the Pony Express System, which began commercial operations in October 2014.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were $144.8 million for the year ended December 31, 2015 compared to $24.7 million for the year ended December 31, 2014. Operating costs and expenses for the year ended December 31, 2015 represents a full year of operations at Pony Express as well as a partial year of operations on the lateral in Northeast Colorado, which began commercial operations during the second quarter of 2015. Operating costs and expenses for the year ended December 31, 2014 represents a partial year of operations at the mainline portion of the Pony Express System, which began commercial operations in October 2014.

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Revenues. Crude Oil Transportation & Logistics segment revenues of $28.3 million for the year ended December 31, 2014 represents transportation revenue on the mainline portion of the Pony Express System, which was placed in service in October 2014. There were no revenues for the year ended December 31, 2013.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were $24.7 million for the year ended December 31, 2014 compared to $3.2 million for the year ended December 31, 2013. Operating costs and expenses for the year ended December 31, 2014 include costs associated with the start of commercial operations in October 2014 as well as the amortization of the Pony Express oil conversion use rights as discussed further in Note 8 – Goodwill and Other Intangible Assets. For the year ended December 31, 2013, operating costs and expenses consisted primarily of the amortization of the Pony Express oil conversion use rights.

The following provides a summary of our Natural Gas Transportation & Logistics segment results of operations for the periods indicated:

Segment Financial Data - Natural Gas Transportation & Logistics [(1)]	Year Ended December 31, 2015	2014	2013
	(in thousands)		
Revenues:			
Natural gas transportation services	$ 125,279	$ 131,990	$ 121,945
Sales of natural gas, NGLs, and crude oil	6,346	7,868	5,906
Processing and other revenues	32	222	26
Total revenues	131,657	140,080	127,877
Operating costs and expenses:			
Cost of sales	6,342	7,025	4,234
Cost of transportation services	10,927	18,090	15,059
Operations and maintenance	27,767	27,422	26,682
Depreciation and amortization	22,927	23,788	30,169
General and administrative	17,052	16,767	20,604
Taxes, other than income taxes	4,840	6,101	7,089
Total operating costs and expenses	89,855	99,193	103,837
Operating income	$ 41,802	$ 40,887	$ 24,040

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 18 – *Reporting Segments* to the accompanying consolidated financial statements.

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Revenues. Natural Gas Transportation & Logistics segment revenues were $131.7 million for the year ended December 31, 2015, compared to $140.1 million for the year ended December 31, 2014, which represents an $8.4 million, or 6%, decrease in segment revenues primarily due to a $6.7 million decrease in natural gas transportation services revenue driven by lower fuel reimbursements as a result of decreased prices and a $1.5 million decrease in revenue from the sales of natural gas, NGLs, and crude oil as a result of a 46% decrease in natural gas prices, partially offset by favorable hedge settlements and increased volumes sold.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation & Logistics segment were $89.9 million for the year ended December 31, 2015 compared to $99.2 million for the year ended December 31, 2014, which represents a decrease of $9.3 million, or 9%. The overall decrease in operating costs and expenses was primarily driven by a $7.2 million decrease in the cost of transportation services, due to lower fuel reimbursements as a result of decreased prices, a $1.3 million decrease in taxes, other than income taxes, due to revised property tax estimates as a result of successful appeals with state taxing authorities on the assessed value of property, a $0.9 million decrease in depreciation and amortization driven by a change in rates at Trailblazer as a result of the rate case settlement in 2014, and a $0.7 million decrease in cost of sales, due to a 51% decrease in natural gas prices, partially offset by increased volumes sold.

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Revenues. Natural Gas Transportation & Logistics segment revenues were $140.1 million for the year ended December 31, 2014, compared to $127.9 million for the year ended December 31, 2013, which represents a $12.2 million, or 10% increase in segment revenues. The increase in segment revenues was driven by a $10.0 million increase in transportation services revenue primarily due to increased transportation volumes at Trailblazer and increased fuel reimbursements as a result of higher prices at TIGT, and a $2.0 million increase in natural gas sales primarily due to 38% higher prices, partially offset by decreased volumes sold.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation & Logistics segment were $99.2 million for the year ended December 31, 2014 compared to $103.8 million for the year ended December 31, 2013, which represents a decrease of $4.6 million, or 4%. The overall decrease in operating costs and expenses was primarily driven by a $6.4 million decrease in depreciation and amortization primarily driven by the sale of the Pony Express Assets in the fourth quarter of 2013 and the decreased depreciation rates included in the Trailblazer rate case settlement in the second quarter of 2014 and a $3.8 million decrease in general and administrative costs, due to the decrease in costs allocated to Trailblazer by TEP in periods subsequent to our acquisition of Trailblazer on April 1, 2014 as compared to the costs allocated to Trailblazer by TD prior to April 1, 2014. These decreases were partially offset by a $2.8 million increase in cost of sales due to increased volumes of natural gas sold and a $3.0 million increase in cost of transportation services due to increased costs at TIGT, primarily driven by increased fuel reimbursements and gas purchases, partially offset by decreased costs at Trailblazer driven by lower fuel costs in 2014 as a result of the Trailblazer rate case settlement.

The following provides a summary of our Processing & Logistics segment results of operations for the periods indicated:

Segment Financial Data - Processing & Logistics [1]	Year Ended December 31, 2015	2014	2013
	(in thousands)		
Revenues:			
Sales of natural gas, NGLs, and crude oil	$ 71,996	$ 173,381	$ 149,794
Processing and other revenues	33,701	35,009	14,775
Total revenues	105,697	208,390	164,569
Operating costs and expenses:			
Cost of sales	64,686	160,520	128,781
Cost of transportation services	687	236	—
Operations and maintenance	12,576	11,438	8,722
Depreciation and amortization	13,381	11,193	6,720
General and administrative	4,441	4,073	3,562
Taxes, other than income taxes	403	353	312
Loss on sale of assets	4,795	—	—
Total operating costs and expenses	100,969	187,813	148,097
Operating income	$ 4,728	$ 20,577	$ 16,472

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 18 – *Reporting Segments* to the accompanying consolidated financial statements.

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Revenues. Processing & Logistics segment revenues were $105.7 million for the year ended December 31, 2015, compared to $208.4 million for the year ended December 31, 2014, which represents a $102.7 million, or 49%, decrease in segment revenues. The decrease in segment revenues was primarily due to a $101.4 million decrease in the sales of natural gas, NGLs, and crude oil driven by a 58% decrease in NGL prices and lower volumes processed, and a $1.3 million decrease in processing and other revenues driven by lower processing fees at TMID due to decreased volumes processed under a large, fee-based contract, partially offset by increased revenue at Water Solutions, including water transportation services and revenue associated with a contract to construct a water pipeline for a customer during the year ended December 31, 2015. Prior to its consolidation in May 2014, TEP's investment in Water Solutions was accounted for under the equity method of accounting and as a result TEP recognized no revenues from Water Solutions for the period from January 1, 2014 to May 13, 2014.

Operating costs and expenses. Operating costs and expenses in the Processing & Logistics segment were $101.0 million for the year ended December 31, 2015 compared to $187.8 million for the year ended December 31, 2014, which represents a decrease of $86.8 million, or 46%. The decrease in operating costs and expenses was driven by a decrease of $95.8 million in cost of sales, primarily due to decreased NGL prices and volumes processed as discussed above. The decrease in cost of sales was partially offset by $4.8 million of non-cash losses recognized on the sale of compressor and other assets in 2015, and overall increases in the cost of transportation services, operations and maintenance costs, depreciation and amortization, and general and administrative costs, all primarily driven by the costs associated with Water Solutions, which was consolidated in May 2014.

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Revenues. Processing & Logistics segment revenues were $208.4 million for the year ended December 31, 2014, compared to $164.6 million for the year ended December 31, 2013, which represents a $43.8 million, or 27%, increase in segment revenues. The increase in segment revenues was primarily due to a $23.6 million increase in sales of natural gas, NGLs, and crude oil driven by increased volumes processed partially offset by a 7% decrease in average NGL prices, a $20.2 million increase in processing fees driven by the conversion of two significant customers from percent of proceeds or keep whole processing contracts to fee-based processing contracts and revenue of $5.0 million from Water Solutions, which was consolidated in May 2014.

Operating costs and expenses. Operating costs and expenses in the Processing & Logistics segment were $187.8 million for the year ended December 31, 2014 compared to $148.1 million for the year ended December 31, 2013, which represents an increase of $39.7 million, or 27%. The increase in operating costs and expenses was driven by an increase of $31.7 million in cost of sales, primarily driven by an increase in NGL producer settlements as a result of increased volumes processed under contracts converted to fee-based as discussed above and an overall increase in volumes processed, partially offset by decreased NGL prices. The overall increases in the cost of transportation services, operations and maintenance costs, depreciation and amortization, and general and administrative costs are all primarily driven by the costs associated with Water Solutions, which was consolidated in May 2014.

Liquidity and Capital Resources Overview

Our primary sources of liquidity for the year ended December 31, 2015 were proceeds from the issuance of common units, cash generated from operations, and borrowings under our revolving credit facility. 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/or 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 maintenance 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 revolving credit facility and issuances of debt and/or equity securities.

Our total liquidity as of December 31, 2015 and 2014 was as follows:

	December 31, 2015	December 31, 2014
	(in thousands)	
Cash on hand	$ 1,611	$ 867
Total capacity under the revolving credit facility	1,100,000	850,000
Less: Outstanding borrowings under the revolving credit facility	(753,000)	(559,000)
Available capacity under the revolving credit facility	347,000	291,000
Total liquidity	$ 348,611	$ 291,867

Revolving Credit Facility

We have a senior secured revolving credit facility with Barclays Bank PLC, as administrative agent, and a syndicate of lenders (the "Credit Agreement") which will mature on May 17, 2018. On June 25, 2014, TEP and certain of its subsidiaries entered into Amendment No. 1 to the Credit Agreement. On November 24, 2015, TEP and certain of its subsidiaries entered into Amendment No. 2 to the Credit Agreement, which modified certain provisions of the Credit Agreement to increase the amount of the revolving credit facility from $850 million to $1.1 billion and provide for a committed accordion in an amount up to an additional $400 million, subject to the satisfaction of certain other conditions. The revolving credit facility includes a $75 million sublimit for letters of credit and a $60 million sublimit for swing line loans. Effective January 4, 2016, in conjunction with the acquisition of an additional 31.3% interest in Pony Express, we exercised the committed accordion feature to increase the total capacity of the revolving credit facility to $1.5 billion. As of January 31, 2016, we had approximately $1.2 billion of outstanding borrowings under our revolving credit facility.

The revolving 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 making such a distribution), 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." In addition, we are required 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. As of December 31, 2015, we are in compliance with the covenants required under the revolving credit facility.

The unused portion of the revolving credit facility is subject to a commitment fee, which which ranges from 0.300% to 0.500%, based on our total leverage ratio. As of December 31, 2015, the weighted average interest rate on outstanding borrowings was 2.08%.

Public Offering

On February 27, 2015, we sold 10,000,000 common units representing limited partner interests in an underwritten public offering at a price of $50.82 per unit, or $49.29 per unit net of the underwriter's discount, for net proceeds of approximately $492.4 million after deducting the underwriter's discount and offering expenses. We used the net proceeds from the offering to fund a portion of the consideration for the acquisition of an additional 33.3% membership interest in Pony Express as discussed in Note 4 – *Acquisitions*. Pursuant to the underwriters' option to purchase additional units, we sold an additional 1,200,000 common units representing limited partner interests to the underwriters at a price of $50.82 per unit, or $49.29 per unit net of the underwriter's discount, for net proceeds of approximately $59.3 million after deducting the underwriter's discount and offering expenses. We used the net proceeds from this additional purchase of common units to reduce borrowings under our revolving credit facility, a portion of which were used to fund the March 2015 acquisition of an additional 33.3% membership interest in Pony Express as discussed in Note 4 – *Acquisitions*.

Equity Distribution Agreement

On October 31, 2014, we entered into an equity distribution agreement pursuant to which we may sell from time to time through a group of managers, as our sales agents, common units representing limited partner interests having an aggregate offering price of up to $200 million, referred to as TEP's At-The-Market Offering Program, or ATM Program. On May 13, 2015, we amended the agreement to reduce the aggregate offering price to $100.2 million in order to account for follow-on equity offerings under our S-3 shelf registration statement. Sales of the common units, if any, will be made by means of ordinary brokers' transactions, to or through a market maker or directly on or through an electronic communication network, a "dark pool" or any similar market venue, or as otherwise agreed by the Partnership and one or more of the managers. We intend to use the net proceeds from any sale of the units for general partnership purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.

During the year ended December 31, 2015, we issued and sold 65,744 common units with a weighted average sales price of $45.58 per unit under our equity distribution agreement for net proceeds of approximately $3.0 million (net of approximately $30,000 in commissions and professional service expenses). We used the net proceeds for general partnership purposes. At December 31, 2015, approximately $95.9 million in aggregate offering price remained available to be issued and sold under the equity distribution agreement.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. While various other factors may impact our working capital requirements from period to period, our working capital requirements have typically been, and we expect will continue to be, 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, payments to suppliers, and the level of spending for capital expenditures. Changes in the market prices of energy commodities, primarily NGLs, that we buy and sell in the normal course of business can also impact the timing of changes in accounts receivable and accounts payable.

As of December 31, 2015, we had a working capital deficit of $11.7 million compared to a working capital surplus of $35.7 million at December 31, 2014, which represents a decrease in working capital of $47.4 million. The overall decrease in working capital was primarily attributable to the following:

- a decrease of $73.4 million in receivables from related parties due to the utilization of the Pony Express cash balance swept to TD under the cash management agreement;
- an increase in deferred revenue of $21.0 million from deficiency payments collected by Pony Express; and
- an increase in accrued taxes of $9.9 million as a result of placing the mainline portion of the Pony Express System into commercial service in October 2014.

These working capital decreases were partially offset by:

- a decrease of $40.1 million in accounts payable, primarily driven by the timing of project invoices and payment of contractor retainages related to the construction of the Pony Express lateral in Northeast Colorado placed in service in April 2015 and lower producer settlements at TMID; and
- an increase of $18.0 million in accounts receivable, primarily driven by the start of commercial operations at the Pony Express lateral in Northeast Colorado and the activation of the Hiland Pipeline Company joint tariff at Pony Express.

A material adverse change in operations, available financing under our revolving credit facility, or available financing from the equity or debt capital markets 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:

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Net cash provided by (used in):			
Operating activities	$ 289,296	$ 79,444	$ 82,482
Investing activities	$ (845,270)	$ (1,102,729)	$ (347,610)
Financing activities	$ 556,718	$ 1,024,152	$ 265,128

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Operating Activities. Cash flows provided by operating activities were $289.3 million and $79.4 million for the years ended December 31, 2015 and 2014, respectively. The increase in net cash flows provided by operating activities of $209.9 million was primarily driven by the increase in operating results and a net increase in cash inflows from changes in working capital, primarily driven by a $31.6 million decrease in net cash outflows from accounts payable and accrued liabilities due to increased property tax accruals and related party payables and a $14.0 million increase in net cash inflows from deficiency payments received by Pony Express, partially offset by a decrease in net cash inflows of $15.3 million from accounts receivable, due to increased receivables at Pony Express.

Investing Activities. Cash flows used in investing activities were $845.3 million and $1.1 billion for the years ended December 31, 2015 and 2014, respectively. During the year ended December 31, 2015, net cash used in investing activities were driven by the $700.0 million cash outflow for the acquisition of an additional 33.3% membership interest in Pony Express, which allowed TD to continue funding the construction at Pony Express, including the lateral in Northeast Colorado, $75.0 million for the acquisition of Western, and capital expenditures of $65.4 million, primarily related to the construction at Pony Express, including the lateral in Northeast Colorado. During the year ended December 31, 2014, net cash used in investing activities was driven by capital expenditures of $665.7 million, primarily due to construction at Pony Express, including the lateral in Northeast Colorado, as well as the capacity expansion projects at TMID and other expansion projects at Trailblazer, cash outflows of $270.0 million associated with the related party loan to TD under the Pony Express cash management agreement, and cash outflows of $150.0 million, $27.0 million, and $7.6 million for the acquisitions of Trailblazer, Pony Express, and Water Solutions, respectively. These cash outflows were partially offset by cash inflows of $20.0 million from the return of funds deposited with Shell in support of the crude oil resale obligation of Pony Express.

Financing Activities. Cash flows provided by financing activities were $556.7 million and $1.0 billion for the years ended December 31, 2015 and 2014, respectively. Financing cash inflows for the year ended December 31, 2015 were primarily driven by $554.1 million from the issuance of 11,200,000 TEP common units in a public offering which closed on February 27, 2015 and TEP common units issued under TEP's ATM Program during 2015 and $194.0 million from net borrowings under the TEP revolving credit facility, the proceeds of which were used to fund the acquisitions discussed above. These financing cash inflows were partially offset by distributions to TEP unitholders and TEP's general partner of $161.8 million as well as distributions to noncontrolling interests of $25.1 million primarily driven by distributions to TD from Pony Express. Cash flows provided by financing activities for the year ended December 31, 2014 were primarily driven by the proceeds from net borrowings under the revolving credit facility of $424.0 million, net proceeds of $320.4 million from the issuance of 8,050,000 common units in a public offering which closed on July 25, 2014 and units issued under the ATM Program in the fourth quarter of 2014, net contributions from Predecessor Entities of $312.1 million, and a contribution from TD of $27.5 million representing the difference between the carrying amount of the Replacement Gas Facilities and the proceeds received from TD. These cash inflows were partially offset by distributions to TEP unitholders of $68.1 million.

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Operating Activities. Cash flows provided by operating activities were $79.4 million and $82.5 million for the years ended December 31, 2014 and 2013, respectively. The decrease in net cash flows provided by operating activities of $3.0 million was primarily driven by the increase in net cash outflows for changes in working capital, primarily due to the timing of payments and a decrease in producer settlements at TMID as a result of lower NGL prices, partially offset by the increase in operating results in the year ended December 31, 2014 compared to the year ended December 31, 2013.

Investing Activities. Cash flows used in investing activities were $1.1 billion and $347.6 million for the years ended December 31, 2014 and 2013, respectively. During the year ended December 31, 2014, net cash used in investing activities was driven by capital expenditures of $665.7 million, primarily due to construction of the Pony Express System, including the lateral in Northeast Colorado, as well as the capacity expansion projects at TMID and other expansion projects at Trailblazer, cash outflows of $270.0 million associated with the related party loan to TD under the Pony Express cash management agreement, and cash outflows of $150.0 million, $27.0 million, and $7.6 million for the acquisitions of Trailblazer, Pony Express, and Water Solutions, respectively. These cash outflows were partially offset by cash inflows of $20 million from the return of funds deposited with Shell in support of the crude oil resale obligation of Pony Express. During the year ended December 31, 2013, net cash used in investing activities was driven by $346.0 million in capital expenditures, consisting primarily of spending on the conversion and construction of the Pony Express System and capacity expansion and efficiency upgrade projects at TMID, and to a lesser extent, capital expenditures at TIGT.

Financing Activities. Cash flows provided by financing activities were $1.0 billion and $265.1 million for the years ended December 31, 2014 and 2013, respectively. Financing cash inflows for the year ended December 31, 2014 were primarily driven by the proceeds from net borrowings under the revolving credit facility of $424.0 million, net proceeds of $320.4 million from the issuance of 8,050,000 common units in a public offering which closed on July 25, 2014 and units issued under the ATM Program in the fourth quarter of 2014, net contributions from Predecessor Entities of $312.1 million, and a contribution from TD of $27.5 million representing the difference between the carrying amount of the Replacement Gas Facilities and the proceeds received from TD. These cash inflows were partially offset by distributions to TEP unitholders of $68.1 million. Cash flows provided by financing activities for the year ended December 31, 2013 consisted primarily of net contributions from Predecessor Entities of $379.9 million, net cash inflows of $290.5 million from the completion of our IPO on May 17, 2013, and net borrowings under our revolving credit facility of $135.0 million. These cash inflows were partially offset by the repayment of $400.0 million of debt assumed from TD, net distributions to TD of $118.5 million prior to the closing of our IPO on May 17, 2013, and distributions to unitholders of $18.2 million.

Distributions

We do not have a legal obligation to pay distributions except as provided in our partnership agreement. A distribution of $0.64 per unit, or $59.0 million in the aggregate, for the three months ended December 31, 2015 was declared on January 4, 2016 and was paid on February 12, 2016 to unitholders of record on January 29, 2016. As of February 17, 2016, we had a total of 67,996,623 common and general partner units outstanding, which equates to an aggregate MQD of approximately $19.5 million per quarter and approximately $78.2 million per year. We intend to pay quarterly distributions at or above the amount of the MQD, which is $0.2875 per unit.

Capital Requirements

The midstream energy business can be capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to consist of, the following:

- maintenance capital expenditures, which are cash expenditures incurred (including expenditures for the construction or development of new capital assets) that we expect to maintain our long-term operating income or operating capacity. These expenditures typically include certain system integrity, compliance and safety improvements; and
- expansion capital expenditures, which are cash expenditures to increase our operating income or operating capacity over the long-term. Expansion capital expenditures include acquisitions or capital improvements (such as additions to or improvements on the capital assets owned, or acquisition or construction of new capital assets).

We expect to incur approximately $27 million for capital expenditures in 2016, of which approximately $15 million is expected for expansion projects and approximately $12 million, net of anticipated reimbursements from affiliates, is expected for maintenance capital expenditures.

The determination of capital expenditures as maintenance or expansion is made at the individual asset level during our budgeting process and as we approve, execute, and monitor our capital spending. The following table summarizes the maintenance and expansion capital expenditures incurred at our consolidated entities:

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Maintenance capital expenditures	$ 12,140	$ 9,913	$ 15,951
Expansion capital expenditures	155,795	762,073	422,981
Total capital expenditures incurred	$ 167,935	$ 771,986	$ 438,932

Capital expenditures incurred represent capital expenditures paid and accrued during the period, inclusive of Pony Express capital expenditures paid by TD on behalf of Pony Express and settled via the cash management agreement. The increase in maintenance capital expenditures to $12.1 million for the year ended December 31, 2015 from $9.9 million for the year ended December 31, 2014 is primarily driven by increased maintenance capital expenditures in the Natural Gas Transportation & Logistics and Processing & Logistics segments. 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 year to year and from quarter to quarter. The decrease in expansion capital expenditures to $155.8 million for the year ended December 31, 2015 from $762.1 million for the year ended December 31, 2014 is primarily driven by the significant spending on the Pony Express System prior to commencement of commercial operations at the mainline portion in October 2014. Expansion capital expenditures of $155.8 million for the year ended December 31, 2015 consisted primarily of spending on the Pony Express System, including the lateral in Northeast Colorado.

The decrease in maintenance capital expenditures to $9.9 million for the year ended December 31, 2014 from $16.0 million for the year ended December 31, 2013 is primarily driven by a decrease in maintenance capital expenditures in the Natural Gas Transportation & Logistics segment due to certain compressor and pipeline integrity projects during the year ended December 31, 2013. The increase in expansion capital expenditures to $762.1 million for the year ended December 31, 2014 from $423.0 million for the year ended December 31, 2013 is primarily driven by increased expenditures associated with the conversion and construction of the mainline portion of the Pony Express System, which was placed in commercial service in October 2014, and spending on the Pony Express System lateral in Northeast Colorado.

In addition, we invested cash in unconsolidated affiliates of $2.0 million and $1.3 million during the years ended December 31, 2014 and 2013, respectively, to fund our share of capital expansion projects. There were no investments in unconsolidated affiliates during the year ended December 31, 2015.

We intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. We expect to fund future capital expenditures with funds generated from our operations, borrowings under our Credit Agreement, the issuance of additional partnership units and/or the issuance of long-term debt. If these sources are not sufficient, we may reduce our discretionary spending.

Contractual Obligations

Following is a summary of our contractual cash obligations in future periods, representing amounts that were fixed and determinable as of December 31, 2015:

	Payments Due By Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
			(in thousands)		
Debt obligations [1]	$ 753,000	$ —	$ 753,000	$ —	$ —
Interest on debt obligations [2]	37,241	15,696	21,545	—	—
Operating lease and service contract obligations [3]	621,069	27,689	56,789	58,853	477,738
Land site lease and right-of-way [4]	1,480	116	280	272	812
Other purchase commitments [5]	13,808	6,295	3,716	3,716	81
Total	$ 1,426,598	$ 49,796	$ 835,330	$ 62,841	$ 478,631

(1) Debt obligations at December 31, 2015 consisted of borrowings under the revolving credit facility. For additional information, see Note 10 – *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, 2015. For additional information, see Note 10 – *Long-term Debt* to the Consolidated Financial Statements in Item 8.—Financial Statements and Supplementary Data.

(3) Operating leases and service contracts consist of leases for crude oil storage as well as office space and equipment. For additional information, see Note 12 – *Commitments & Contingent Liabilities* to the Consolidated Financial Statements in Item 8.—Financial Statements and Supplementary Data.

(4) Land site lease and right-of-way contracts consist of payments to landowners, primarily in our Crude Oil Transportation & Logistics and Natural Gas Transportation & Logistics segments. For additional information, see Note 12 – *Commitments & 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 and operating and maintenance expenditures.

On May 17, 2013, in connection with the closing of TEP's IPO, TEP and its general partner entered into the TEP Omnibus Agreement, which provides that, among other things, TEP will reimburse TD and its affiliates for all expenses they incur and payments they make on TEP's 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. In addition to these costs, TEP pays a quarterly reimbursement to TD for costs associated with being a public company.

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.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Impairment of Long-lived Assets		
We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections expected to be realized over the remaining useful life of the primary asset. The carrying amount is not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value.	We review our long-lived assets for impairment whenever events or changes in circumstances indicated that the carrying amount of an asset may not be recoverable. Our impairment analyses require management to apply judgment in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, including anticipated volumes, contract renewals and changes in our regulated rates, and selecting the discount rate that reflects the risk inherent in future cash flows. If the carrying value is not recoverable, we assess the fair value of long-lived assets using a discounted cash flow model and other commonly accepted techniques.	Using the impairment review methodology described herein, we have not recorded any impairment charges on long-lived assets during the year ended December 31, 2015. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Impairment of 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 determine fair value using widely accepted valuation techniques, primarily discounted cash flow and market multiple analyses. These techniques are also used when assigning the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. Our impairment analyses require management to apply judgment in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, including anticipated volumes, contract renewals and changes in our regulated rates, and selecting the discount rate that reflects the risk inherent in future cash flows. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.	We primarily use a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If our assumptions are not appropriate, or future events indicate that our goodwill is impaired, our net income would be impacted by the amount by which the carrying value exceeds the fair value of the reporting unit, to the extent of the balance of goodwill. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill impairment for reporting units due to the potential impact on our operations and cash flows. We completed our impairment testing of goodwill in the third quarter of 2015 using the methodology described herein, and determined there was no impairment. As a result of a decreased commodity prices in late 2015 and into early 2016, which caused a significant drop in the volumes anticipated from several producers from which TMID receives natural gas for processing, we identified a potential impairment trigger with respect to the $79.2 million of goodwill at the TMID reporting unit, which is a component of our Processing & Logistics segment. We tested TMID's goodwill for impairment as of December 31, 2015 and determined that the fair value of the reporting unit exceeds the carrying value by approximately 21%. As a result, no impairment charge was recorded, however our analysis includes assumptions of a gradual recovery of commodity prices and a corresponding increase in volumes over time. If our outlook for long-term commodity prices is not realized, or our producers further decrease volumes, we could have an impairment in the future.
Risk Management Activities		
Derivative assets and liabilities are recorded on our consolidated balance sheets at their estimated fair value as of each reporting date. Changes in the fair value of derivative contracts are recognized in earnings in the period in which the change occurs.	When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical information and the expected relationship with quoted market prices.	If our estimates of fair value are inaccurate, we may be exposed to losses or gains that could be material. As of December 31, 2015, we had no natural gas hedges outstanding and thus no fair value change due to a hypothetical increase in the natural gas price forward curve.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
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.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

As of December 31, 2015 approximately 92% of our reserved processing capacity was subject to firm or volumetric fee contracts, with the majority of fee revenue based on the volumes actually processed. The remaining 8% was subject to commodity sensitive contracts such as percent of proceeds or keep whole processing contracts. The profitability of our commodity sensitive processing contracts that include keep whole or percent of proceeds components is affected by volatility in prevailing NGL and natural gas prices. We do not currently hedge the commodity exposure in our commodity sensitive contracts in our Processing & Logistics segment and we do not expect to in the foreseeable future. During 2015, NGL and natural gas prices declined substantially and these declines directly and indirectly resulted in lower processing volumes and realizations on our percent of proceeds and keep whole processing contracts. Our Processing & Logistics segment comprised approximately 9%, 30% and 30% of our Adjusted EBITDA for the years ended December 31, 2015, 2014 and 2013, respectively.

The following table summarizes the percentage of our Adjusted EBITDA at each reportable segment by contract type for the year ended December 31, 2015:

	Crude Oil Transportation & Logistics	Natural Gas Transportation & Logistics	Processing & Logistics	Corporate & Other	Consolidated
Firm fee	65%	26%	4%	— %	95%
Volumetric fee	—%	1%	3%	— %	4%
Commodity exposed	—%	—%	1%	— %	1%
Other	—%	—%	1%	(1)%	—%
Total	65%	27%	9%	(1)%	100%

We have a limited amount of direct commodity price exposure related to crude oil collected as part of our contractual pipeline loss allowance at Pony Express. We do not currently hedge this commodity exposure, but we may enter into hedging agreements in the future. 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. As of December 31, 2015, we had no natural gas hedges outstanding.

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. As of December 31, 2015 we had no natural gas hedges outstanding and thus no fair value change due to a hypothetical increase in the natural gas price forward curve.

The CFTC has promulgated regulations to implement Dodd-Frank Act's changes to the CEA, 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 those 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 CEA 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, TEP currently has a $1.5 billion revolving credit facility. Borrowings under the revolving 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 June 25, 2014, the applicable margin ranges from 0.75% to 2.75%, 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 $0.3 million based on our debt obligations as of December 31, 2015.

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, guarantees or bonds 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 firm fee contracts with high-quality customers. As of December 31, 2015 approximately 63% of our revenues are derived from customers who have investment grade credit ratings or are part of corporate families with investment grade credit ratings.

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, equity and cash flows present fairly, in all material respects, the financial position of Tallgrass Energy Partners, LP and its subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our audits (which was an integrated audit in 2015). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management’s Report on Internal Control over Financial Reporting, management has excluded BNN Western, LLC ("Western") from its assessment of internal control over financial reporting as of December 31, 2015 because it was acquired by the Company in a purchase business combination during 2015. We have also excluded Western from our audit of internal control over financial reporting. Western is a wholly owned subsidiary whose total assets and total revenues represent 3% and less than 1%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2015.

/s/PricewaterhouseCoopers LLP

Denver, Colorado
February 17, 2016

TALLGRASS ENERGY PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2015	December 31, 2014
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,611	$ 867
Accounts receivable, net	57,742	39,768
Receivable from related parties	15	73,393
Gas imbalances	1,227	2,442
Inventories	13,793	13,045
Prepayments and other current assets	2,835	2,766
Total Current Assets	77,223	132,281
Property, plant and equipment, net	2,025,018	1,853,081
Goodwill	343,288	343,288
Intangible asset, net	96,546	104,538
Deferred financing costs, net	5,105	5,528
Deferred charges and other assets	14,894	18,481
Total Assets	$ 2,562,074	$ 2,457,197
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities:		
Accounts payable, including $10,554 and $45,534 related to variable interest entities	$ 22,218	$ 62,329
Accounts payable to related parties	7,852	3,915
Gas imbalances	1,605	3,611
Accrued taxes	13,844	3,989
Accrued liabilities	10,019	9,384
Deferred revenue	26,511	5,468
Other current liabilities	6,880	7,872
Total Current Liabilities	88,929	96,568
Long-term debt	753,000	559,000
Other long-term liabilities and deferred credits	5,143	6,478
Total Long-term Liabilities	758,143	565,478
Commitments and Contingencies		
Equity:		
Common unitholders (60,644,232 and 32,834,105 units issued and outstanding at December 31, 2015 and 2014, respectively)	1,618,766	800,333
Subordinated unitholder (0 and 16,200,000 units issued and outstanding at December 31, 2015 and 2014)	—	274,133
General partner (834,391 units issued and outstanding at December 31, 2015 and 2014, respectively)	(348,841)	(35,743)
Total Partners' Equity	1,269,925	1,038,723
Noncontrolling interests	$ 445,077	$ 756,428
Total Equity	$ 1,715,002	$ 1,795,151
Total Liabilities and Equity	$ 2,562,074	$ 2,457,197

TALLGRASS ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2015	2014	2013
	(in thousands, except per unit amounts)		
Revenues:			
Crude oil transportation services	$ 300,436	$ 28,343	$ —
Natural gas transportation services	119,895	126,733	120,025
Sales of natural gas, NGLs, and crude oil	82,133	181,249	155,700
Processing and other revenues	33,733	35,231	14,801
Total Revenues	536,197	371,556	290,526
Operating Costs and Expenses:			
Cost of sales (exclusive of depreciation and amortization shown below)	75,285	167,545	131,095
Cost of transportation services (exclusive of depreciation and amortization shown below)	53,597	24,109	15,059
Operations and maintenance	49,138	39,577	35,404
Depreciation and amortization	83,476	47,048	39,917
General and administrative	50,195	33,160	27,651
Taxes, other than income taxes	21,796	6,704	7,401
Loss on sale of assets	4,795	—	—
Total Operating Costs and Expenses	338,282	318,143	256,527
Operating Income	197,915	53,413	33,999
Other (Expense) Income:			
Interest expense, net	(15,514)	(7,292)	(11,054)
Gain on remeasurement of unconsolidated investment	—	9,388	—
Loss on extinguishment of debt	(226)	—	(17,526)
Equity in earnings of unconsolidated investment	—	717	—
Other income, net	2,639	3,103	2,205
Total Other (Expense) Income	(13,101)	5,916	(26,375)
Net income	184,814	59,329	7,624
Net (income) loss attributable to noncontrolling interests	(24,268)	11,352	2,123
Net income attributable to partners	$ 160,546	$ 70,681	$ 9,747
Allocation of income to the limited partners:			
Net income attributable to partners	$ 160,546	$ 70,681	$ 9,747
Predecessor operations interest in net (income) loss	—	(1,508)	4,432
Net income attributable to partners, excluding predecessor operations interest	160,546	69,173	14,179
Net income attributable to partners prior to May 17, 2013	—	—	(6,982)
Net income attributable to partners subsequent to May 17, 2013	160,546	69,173	7,197
General partner interest in net income subsequent to May 17, 2013	(46,478)	(7,399)	(206)
Common and subordinated unitholders' interest in net income subsequent to May 17, 2013	$ 114,068	$ 61,774	$ 6,991
Basic net income per common and subordinated unit	$ 1.95	$ 1.39	$ 0.17
Diluted net income per common and subordinated unit	$ 1.91	$ 1.36	$ 0.17
Basic average number of common and subordinated units outstanding	58,597	44,346	40,450
Diluted average number of common and subordinated units outstanding	59,575	45,394	41,458

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

TALLGRASS ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF EQUITY

	TEP Predecessor Member's Capital	Predecessor Equity	Limited Partners				General Partner		Total Partners' Equity	Noncontrolling Interests	Total Equity
			Common		Subordinated						
			Units	Amount	Units	Amount	Units	Amount			
						(in thousands)					
Balance at January 1, 2013	$ 571,834	$ 121,446	—	$ —	—	$ —	—	$ —	$ 693,280	$ 70,397	$ 763,677
Net income (loss) attributable to to the period from January 1, 2013 to May 16, 2013	6,982	(1,172)	—	—	—	—	—	—	5,810	(761)	5,049
Distributions to Member, net	(118,538)	—	—	—	—	—	—	—	(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, net of offering costs	—	—	14,600	290,483	—	—	—	—	290,483	—	290,483
Net (loss) income attributable to the period from May 17, 2013 to December 31, 2013	—	(3,260)	—	4,194	—	2,797	—	206	3,937	(1,362)	2,575
Distributions to unitholders	—	—	—	(10,685)	—	(7,123)	—	(363)	(18,171)	—	(18,171)
Noncash compensation expense	—	—	—	4,154	—	—	—	—	4,154	—	4,154
Contributions from Predecessor Entities, net	—	130,207	—	—	—	—	—	—	130,207	249,665	379,872
Balance at December 31, 2013	$ —	$ 247,221	24,300	$ 455,197	16,200	$ 274,666	827	$ 14,078	$ 991,162	$ 317,939	$ 1,309,101
Net income (loss)	—	1,508	—	39,141	—	22,633	—	7,399	70,681	(11,352)	59,329
Issuance of units to public, net of offering costs	—	—	8,079	320,385	—	—	—	—	320,385	—	320,385
Noncash compensation expense	—	—	—	10,154	—	—	—	—	10,154	—	10,154
Distributions to unitholders	—	—	—	(41,567)	—	(23,166)	—	(3,384)	(68,117)	—	(68,117)
Contribution from TD	—	—	—	—	—	—	—	27,488	27,488	—	27,488
(Distributions to) Contributions from Predecessor Entities, net	—	(97,887)	—	—	—	—	—	—	(97,887)	410,012	312,125
Contributions from Noncontrolling Interest	—	—	—	—	—	—	—	—	—	5,429	5,429
Distributions to Noncontrolling Interests	—	—	—	—	—	—	—	—	—	(5,406)	(5,406)
Issuance of general partner units	—	—	—	—	—	—	8	263	263	—	263
Acquisition of Trailblazer	—	(91,090)	385	14,023	—	—	—	(72,933)	(150,000)	—	(150,000)
Acquisition of Water Solutions	—	—	—	—	—	—	—	—	—	1,400	1,400
Acquisition of 33.3% Pony Express membership interest	—	(59,752)	70	3,000	—	—	—	(8,654)	(65,406)	38,406	(27,000)
Balance at December 31, 2014	$ —	$ —	32,834	$ 800,333	16,200	$ 274,133	835	$ (35,743)	$1,038,723	$ 756,428	$ 1,795,151
Net income	—	—	—	108,888	—	5,180	—	46,478	160,546	24,268	184,814
Issuance of units to public, net of offering costs	—	—	11,266	554,084	—	—	—	—	554,084	—	554,084
Noncash compensation expense	—	—	—	9,337	—	—	—	—	9,337	—	9,337
Distributions to unitholders	—	—	—	(118,729)	—	(7,857)	—	(35,248)	(161,834)	—	(161,834)
Common units issued under LTIP, net of units tendered by employees to satisfy tax withholding obligations	—	—	344	(6,603)	—	—	—	—	(6,603)	—	(6,603)

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

Contributions from Noncontrolling Interest....	—	—	—	—	—	—	—	—	—	110,127	110,127
Distributions to Noncontrolling Interests ..	—	—	—	—	—	—	—	—	—	(69,474)	(69,474)
Acquisition of additional 33.3% membership interest in Pony Express ..	—	—	—	—	—	—	—	(324,328)	(324,328)	(375,672)	(700,000)
Acquisition of noncontrolling interests ...	—	—	—	—	—	—	—	—	—	(600)	(600)
Conversion of subordinated units...........	—	—	16,200	271,456	(16,200)	(271,456)	—	—	—	—	—
Balance at December 31, 2015	$ —	$ —	60,644	$1,618,766	—	$ —	835	$ (348,841)	$1,269,925	$ 445,077	$ 1,715,002

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

TALLGRASS ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Cash Flows from Operating Activities:			
Net income	$ 184,814	$ 59,329	$ 7,624
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	87,367	49,041	41,663
Gain on remeasurement of unconsolidated investment	—	(9,388)	—
Loss on extinguishment of debt	226	—	17,526
Noncash compensation expense	5,103	5,136	1,798
Loss on sale of assets	4,795	—	—
Changes in components of working capital:			
Accounts receivable and other	(15,605)	(348)	8,506
Gas imbalances	(757)	1,504	2,393
Inventories	(5,169)	(8,367)	(2,807)
Accounts payable and accrued liabilities	9,799	(21,787)	12,207
Deferred revenue	20,612	6,619	—
Deferred lease payment	—	—	(4,563)
Other operating, net	(1,889)	(2,295)	(1,865)
Net Cash Provided by Operating Activities	289,296	79,444	82,482
Cash Flows from Investing Activities:			
Capital expenditures	(65,387)	(665,650)	(346,020)
Issuance of related party loan	—	(270,000)	—
Acquisition of Western	(75,000)	—	—
Acquisition of Trailblazer	—	(150,000)	—
Acquisition of additional equity interests in Water Solutions	—	(7,600)	—
Acquisition of Pony Express membership interest	(700,000)	(27,000)	—
Other investing, net	(4,883)	17,521	(1,590)
Net Cash Used in Investing Activities	(845,270)	(1,102,729)	(347,610)
Cash Flows from Financing Activities:			
Distributions to unitholders	(161,834)	(68,117)	(18,171)
Distributions to noncontrolling interests	(25,136)	—	—
Contribution from TD	—	27,488	—
Repayment of debt assumed from TD	—	—	(400,000)
Borrowings under revolving credit facility, net	194,000	424,000	135,000
Proceeds from public offering, net of offering costs	554,084	320,385	290,483
Contributions from Predecessor Entities, net	—	312,125	379,872
Distributions to Member, net	—	—	(118,538)
Other financing, net	(4,396)	8,271	(3,518)
Net Cash Provided by Financing Activities	556,718	1,024,152	265,128
Net Change in Cash and Cash Equivalents	744	867	—
Cash and Cash Equivalents, beginning of period	867	—	—
Cash and Cash Equivalents, end of period	$ 1,611	$ 867	$ —

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

Supplemental Disclosures:						
Cash payments for interest, net	$	(14,021)	$	(6,801)	$	(3,450)
Schedule of Noncash Investing and Financing Activities:						
Property, plant and equipment acquired via the cash management agreement with TD	$	138,936	$	158,357	$	—
Contributions from noncontrolling interests settled via the cash management agreement with TD	$	68,277	$	—	$	—
Distributions to noncontrolling interests settled via the cash management agreement with TD	$	(69,017)	$	(5,361)	$	—
Increase in accrual for payment of property, plant and equipment	$	—	$	—	$	90,373
Increase in accrual for reimbursable construction in progress projects	$	—	$	—	$	14,470
Fair value of assets acquired by TEP Predecessor	$	—	$	—	$	1,027,127
Fair value of liabilities acquired by TEP Predecessor	$	—	$	—	$	(566,849)

1. Description of Business

Tallgrass Energy Partners, LP ("TEP" or the "Partnership") is a publicly traded, growth-oriented limited partnership formed to own, operate, acquire and develop midstream energy assets in North America. "We," "us," "our" and similar terms refer to TEP together with its consolidated subsidiaries. We currently provide crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through our membership interest in Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which owns a crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma that includes a lateral in Northeast Colorado that commences in Weld County, Colorado, and interconnects with the pipeline just east of Sterling, Colorado (the "Pony Express System"). We provide natural gas transportation and storage services for customers in the Rocky Mountain and Midwest regions of the United States through the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system located in Colorado, Kansas, Missouri, Nebraska and Wyoming (the "TIGT System"), and a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Nebraska (the "Trailblazer Pipeline"). We also provide services for customers in Wyoming at the Casper and Douglas natural gas processing facilities and the West Frenchie Draw natural gas treating facility (collectively, the "Midstream Facilities"), and NGL transportation services in Northeast Colorado. We perform water business services in Colorado and Texas through BNN Water Solutions, LLC ("Water Solutions"). Our operations are strategically located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg, Powder River, Wind River, Permian and Hugoton-Anadarko Basins and the Niobrara, Mississippi Lime, Eagle Ford and Bakken shale formations.

Our reportable business segments are:

- Crude Oil Transportation & Logistics—the ownership and operation of a crude oil pipeline system;
- Natural Gas Transportation & Logistics—the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities; and
- Processing & Logistics—the ownership and operation of natural gas processing, treating and fractionation facilities, the provision of water business services primarily to the oil and gas exploration and production industry and the transportation of NGLs.

The table below summarizes our equity ownership as of December 31, 2015:

Unit Holder	Limited Partner Common Units	General Partner Units	Percentage of Outstanding Limited Partner Common Units	Percentage of Outstanding Common and General Partner Units
Public Unitholders	34,288,752	—	56.54%	55.77%
Tallgrass Equity, LLC	20,000,000	—	32.98%	32.53%
Tallgrass Development, LP	6,355,480	—	10.48%	10.34%
Tallgrass MLP GP, LLC (1)	—	834,391	—	1.36%
Total	60,644,232	834,391	100.00%	100.00%

(1) Tallgrass MLP GP, LLC (the "general partner") also holds all of TEP's incentive distribution rights ("IDRs").

The term "TEP Predecessor" refers to Tallgrass Energy Partners Predecessor, which is comprised of businesses that were owned by Tallgrass Development, LP ("TD") from November 13, 2012 through the completion of the initial public offering on May 17, 2013 ("IPO"). The businesses included in the TEP Predecessor consist of Tallgrass Interstate Gas Transmission, LLC ("TIGT") and Tallgrass Midstream, LLC ("TMID"), in addition to the businesses described below.

The term "Trailblazer Predecessor" refers to Trailblazer Pipeline Company LLC ("Trailblazer") for the period from November 13, 2012 to its acquisition by TEP on April 1, 2014, and the term "Pony Express Predecessor" refers to Pony Express for the period from November 13, 2012 to September 1, 2014, the date on which TEP acquired a 33.3% membership interest. TEP Predecessor, Trailblazer Predecessor and Pony Express Predecessor are collectively referred to as the Predecessor Entities, as further discussed in Note 2 – *Summary of Significant Accounting Policies*. Financial results for all prior periods have been recast to reflect the operations of the Predecessor Entities. Predecessor Equity as presented in the consolidated financial statements represents the capital account activity of Trailblazer Predecessor prior to April 1, 2014 and of Pony Express Predecessor prior to September 1, 2014. For additional information regarding these acquisitions, see Note 4 – *Acquisitions*.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying financial statements and related notes were prepared in accordance with the generally accepted accounting principles ("GAAP") contained in the Financial Accounting Standards Board's Accounting Standards Codification. 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 consolidated financial statements of TEP include historical cost-basis accounts of the assets of TEP Predecessor, contributed to TEP by TD in connection with the IPO, for the periods prior to May 17, 2013, the closing date of TEP's IPO, as well as Trailblazer for the periods prior to April 1, 2014, the date TEP acquired Trailblazer from TD, and Pony Express for the periods prior to September 1, 2014, the date TEP acquired a controlling 33.3% membership interest in Pony Express, 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 transfers between the entities of the assets and liabilities have 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.

As further discussed in Note 4 – *Acquisitions*, TEP closed the acquisition of Trailblazer on April 1, 2014 and the acquisition of a 33.3% membership interest in Pony Express effective September 1, 2014. As the acquisitions of Trailblazer and the initial 33.3% membership interest in Pony Express are considered transactions between entities under common control, and a change in reporting entity, the financial information presented for prior periods has been recast to include Trailblazer and the initial 33.3% membership interest in Pony Express for all periods presented. The acquisition of the additional 33.3% membership interest in Pony Express represents a transaction between entities under common control and an acquisition of noncontrolling interests. As a result, financial information for periods prior to March 1, 2015 have not been recast to reflect the additional 33.3% membership interest.

The consolidated financial statements include the accounts of TEP and its subsidiaries and controlled affiliates. Significant intra-entity items have been eliminated in the presentation. Net equity contributions of the TEP Predecessor included in the consolidated statements of cash flows represent transfers of cash as a result of TD's centralized cash management systems prior to May 17, 2013, and prior to April 1, 2014 for Trailblazer and September 1, 2014 for Pony Express, 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. As of December 31, 2015, Pony Express participated in a cash management agreement with TD, which held a 33.3% common membership interest in Pony Express as of December 31, 2015, under which cash balances were swept periodically and recorded as loans from Pony Express to TD.

Net income or loss from consolidated subsidiaries that are not wholly-owned by TEP is attributed to TEP and noncontrolling interests. This is done in accordance with substantive profit sharing arrangements, which generally follow the allocation of cash distributions and may not follow the respective ownership percentages held by TEP. Concurrent with TEP's acquisition of an initial 33.3% membership interest in Pony Express effective September 1, 2014, TEP, TD, and Pony Express entered into the Second Amended and Restated Limited Liability Agreement of Tallgrass Pony Express Pipeline, LLC ("the Second Amended Pony Express LLC Agreement"), which provided TEP a minimum quarterly preference payment of $16.65 million (prorated to approximately $5.4 million for the quarter ended September 30, 2014) through the quarter ended September 30, 2015. Effective March 1, 2015 with TEP's acquisition of an additional 33.3% membership interest in Pony Express, the Second Amended Pony Express LLC Agreement was further amended (as amended, "the Pony Express LLC Agreement") to increase the minimum quarterly preference payment to $36.65 million (prorated to approximately $23.5 million for the quarter ended March 31, 2015) and extend the term of the preference period through the quarter ended December 31, 2015. The Pony Express LLC Agreement provides that the net income or loss of Pony Express be allocated, to the extent possible, consistent with the allocation of Pony Express cash distributions. Under the terms of the Pony Express LLC Agreement, Pony Express distributions and net income for periods beginning after December 31, 2015 will be attributed to TEP and its noncontrolling interests in accordance with the respective ownership interests.

A variable interest entity ("VIE") is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has a variable interest that could be significant to the VIE and the power to direct the activities that most significantly impact the entity's economic performance. We have presented separately in our consolidated balance sheets, to the extent material, the assets of our consolidated VIE that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of our consolidated VIE for which creditors do not have recourse to our general credit. Pony Express is considered to be a VIE under the applicable authoritative guidance. Based on a qualitative analysis in accordance with the applicable authoritative guidance, we have determined that we are the primary beneficiary as we have the power to direct matters that most significantly impact the activities of Pony Express and have the right to receive benefits of Pony Express that could potentially be significant to Pony Express. We have consolidated Pony Express accordingly. For additional information see Note 3 – *Variable Interest Entities*.

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 our 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

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

On November 12, 2012, TIGT and TMID entered into a centralized cash management agreement with TD. In accordance with the cash management agreement, the subsidiary companies made 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 agreements described below in Note 5 – *Related Party Transactions*, was transferred to an interest bearing account and 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 with the exception of certain balances payable from Pony Express to TD, which have been settled against the receivable from TD via the Pony Express cash management agreement.

Net equity distributions of the Predecessor Entities included in the Consolidated Statements of Cash Flows represent transfers of cash as a result of TD's centralized cash management systems prior to May 17, 2013, and prior to April 1, 2014 for Trailblazer and September 1, 2014 for Pony Express, 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. As of December 31, 2015, Pony Express participated in a cash management agreement with TD, which held a 33.3% common membership interest in Pony Express as of December 31, 2015, under which cash balances were swept daily and recorded as loans from Pony Express to TD.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are carried at their estimated collectible amounts. We 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 $0.6 million and $0.5 million at December 31, 2015 and 2014, respectively.

Inventories

Inventories primarily consist of gas in underground storage, materials and supplies, natural gas liquids and crude oil. Gas in underground storage, sometimes referred to as working gas, and natural gas liquids are recorded at the lower of historical cost or market using the average cost method. As discussed further under "*Revenue Recognition*" below, a loss allowance is factored into the crude oil tariffs to offset losses in transit. As crude oil is transported, we earn oil for our services as pipeline allowance oil, which we can then sell. As pipeline allowance oil is accumulated, it is recorded as inventory at the lower of historical cost or market using the average cost method. 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 associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. We recorded regulatory assets of approximately $2.8 million and $1.4 million included in "Deferred charges and other assets" in the consolidated balance sheets at December 31, 2015 and 2014, respectively. Regulatory assets at December 31, 2015 were primarily attributable to costs associated with both TIGT's 2015 Rate Case Filing and Trailblazer’s 2013 Rate Case Filing as more fully described in Note 16 – *Regulatory Matters*, while regulatory assets at December 31, 2014 were primarily attributable to costs associated with Trailblazer’s 2013 Rate Case Filing. We recorded regulatory liabilities of approximately $2.2 million and $2.3 million included in "Other current liabilities" in the consolidated balance sheet at December 31, 2015 and 2014, respectively, related to Trailblazer's fuel tracker liabilities as described in Note 16 – *Regulatory Matters.*

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 and depreciated over the remaining useful life of the asset or major asset component. We also capitalize certain costs 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.

Intangible Assets

We account for intangible assets in accordance with ASC 805, which established that an intangible asset is identifiable if it meets either the separability criterion or the contractual-legal criterion. Further, in accordance with ASC 805, contract-based intangible assets represent the value of rights that arise from contractual arrangements. Use rights such as drilling, water, air, timber cutting, and route authorities are an example of contract-based intangible assets. Intangible assets arose at Pony Express from the acquisition of rights associated with the ability and regulatory permissions to convert a section of TIGT's natural gas pipeline, which was subsequently purchased by Pony Express, to crude oil and includes the operational and financial benefits that accrue due to those rights and the ability to make that asset more valuable ("the Pony Express oil conversion use rights"). These intangible assets are amortized on a straight-line basis over a period of 35 years, the period of expected future benefit. Intangible assets arose at BNN Redtail, LLC ("Redtail") as a result of a significant customer contract with favorable market terms which was acquired as part of the Water Solutions transaction discussed in Note 4 – *Acquisitions.* This intangible asset was amortized on a straight-line basis over a period of 1.6 years, the remaining term of the contract at the time of acquisition, and was fully amortized as of December 31, 2015.

Impairment of Long-Lived Assets

We review our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or asset group may not be recoverable. An impairment loss results when the estimated undiscounted future net cash flows expected to result from the asset or asset group’s use and its eventual disposition are less than its carrying amount. We assess our long-lived assets for impairment in accordance with the relevant Codification guidance. A long-lived asset or asset group 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, we 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, which refers to the volumes necessary to maintain pressure and deliverability requirements in our storage facilities. We record base gas as a component of property, plant and equipment.

We maintain working gas in our underground storage facilities on behalf of certain third parties. We receive a fee for our storage services but do not reflect the value of third-party gas in the accompanying consolidated financial statements. We occasionally acquire volumes of working gas for our own account. These volumes of working gas are recorded as natural gas inventory at the lower of cost or market.

Depreciation and Amortization

For non-regulated assets, we have elected to use the straight-line method of depreciation. For our regulated assets, we have elected to compute 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. The rates of depreciation for the various classes of depreciable assets are as follows:

	Range of Depreciation Rates
Crude oil pipelines	2.8%
Natural gas pipelines	0.7 - 3.4%
Processing & treating assets	3.3%
Water business assets	3.3 - 20.0%
Replacement Gas Facilities [1]	10.0%
General & other	6.8 - 12.0%

(1) Represents the Replacement Gas Facilities as discussed in Note 5 – *Related Party Transactions* and Note 16 – *Regulatory Matters.*

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 applicable average market index prices.

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.

Goodwill

We evaluate goodwill for impairment on an annual basis and whenever events or changes in circumstances necessitate an evaluation for impairment. Examples of such facts and circumstances include changes in the magnitude of the excess of the fair value over the carrying amount in the last valuation or changes in the business environment. Our annual impairment testing date is August 31st. We evaluate goodwill for impairment at the 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. 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. See Note 8 – *Goodwill and Other Intangible Assets* for additional information regarding impairment testing performed during 2015.

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.

Our investment in Grasslands Water Services I, LLC ("GWSI"), which owns a fresh water transportation pipeline, was initially recorded under the equity method of accounting as we had the ability to exercise significant influence, but not control, over this investment. There was $0.7 million equity in earnings recognized for the year ended December 31, 2014. There were no equity in earnings recognized for the year ended December 31, 2015. As discussed in Note 4 – *Acquisitions*, during the year ended December 31, 2014, TEP acquired a controlling interest in GWSI, which was subsequently renamed BNN Redtail, LLC ("Redtail"), and consolidated its investment in Redtail as of May 13, 2014 accordingly.

Revenue Recognition

We 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. We provide various types of natural gas storage and transportation services and crude oil transportation services to our customers in which the commodity remains the property of these customers at all times.

Crude oil transportation services occur in the Crude Oil Transportation & Logistics segment. We provide various types of crude oil transportation services to our customers and, other than pipeline allowance oil, do not take title to the crude oil and do not incur the risks and rewards of ownership. In many cases the customer has committed to ship a fixed quantity of oil barrels per month. For barrels physically received by us and delivered to the customers' agreed upon destination point, revenue is recognized in the period the service is provided. Shipper deficiencies, or barrels committed by the customer to be transported in a month but not physically received by us for transport or delivered to the customers' agreed upon destination point, are charged at the committed tariff rate per barrel and recorded as a deferred liability until the barrels are physically transported and delivered. In the case of non-committed shippers, revenue is recognized in the same manner utilized for the barrels physically transported and delivered. A loss allowance is factored into the crude oil tariffs to offset losses in transit. As crude oil is transported, we earn oil for our services as pipeline allowance oil. Any pipeline allowance oil that remains after replacing losses in transit can be sold. We take title and record revenue at market prices when the volumes included in the pipeline loss allowance are delivered from the customer. When pipeline loss allowance oil is eventually sold we record revenue at the contractual sales price and cost of sales at average cost as discussed in *"Inventories"* above.

Natural gas transportation and storage services occur in the Natural Gas Transportation & Logistics 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 customers' agreed upon delivery point, or when the volumes are injected into/withdrawn from our storage facilities. In other cases (generally described as "interruptible service"), there is no fixed 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 "firm" and "interruptible" transportation services, we 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.

Natural gas liquids sales occur in the Processing & Logistics segment and consist of the sale of outputs from our processing plants and the marketing of natural gas liquids that are delivered by our suppliers under either fee-based arrangements or percent-of-proceeds arrangements. Under these arrangements, we treat and process the natural gas delivered by our suppliers, and then sell the resulting NGLs and condensate based on published index market prices. We remit to the producers an agreed-upon percentage of the actual proceeds that we receive from our sales of the NGLs and condensate. We keep the difference between the proceeds received and the amount remitted back to the producer. We generally report gross revenues in the consolidated statements of income, as we typically act as the principal in these transactions, take custody of the product, and incur the risks and rewards of ownership. Processing and other revenues primarily represent fees for processing, treating and fractionation of natural gas and NGLs earned under fee-based arrangements and revenue from water services earned in the Processing & Logistics segment.

Natural gas sales occur in both the Natural Gas Transportation & Logistics segment and in the Processing & Logistics segment. In the Natural Gas Transportation & Logistics segment, transportation services revenue is recognized 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. 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 at average cost. In addition, when operational conditions allow, we occasionally sell "base gas," which refers to the minimum volume of natural gas required in order to operate the storage facility. In the Processing & Logistics 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.

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

We expense or capitalize, as appropriate, environmental expenditures that relate to current operations. We expense amounts that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation. We 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. We 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 we 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
- 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 9 – *Risk Management*. For information regarding the fair value of financial instruments not measured at fair value in the consolidated balance sheets, see Note 10 – *Long-term Debt*.

Risk Management Activities

We utilize energy derivatives for the purpose of mitigating our risk resulting from fluctuations in the market price of natural gas. We record derivative contracts at their estimated fair values as of each reporting date. For more information on our risk management activities, see Note 9 – *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 15 – *Equity-Based Compensation*, a portion of the expense recognized relating to equity-based compensation grants is charged to TD.

Income Taxes

Prior to September 1, 2014, TEP was comprised solely of limited liability companies that were flow-through entities (that is, partnerships or disregarded entities) for income tax purposes. As discussed above, effective September 1, 2014 TEP acquired a 33.3% membership interest in Pony Express, which in turn owned 99.8% of Tallgrass Pony Express Pipeline (Colorado), Inc. ("PXP Colorado"), a C corporation. At that time, PXP Colorado was in the process of constructing the lateral in Northeast Colorado and had not yet commenced operations or generated any income. PXP Colorado was subsequently merged into Pony Express prior to the commencement of commercial operations on the lateral in Northeast Colorado.

On September 14, 2015, TEP, through its membership interest in Pony Express, formed a new C corporation, Tallgrass Colorado Pipeline, Inc. ("Tallgrass Colorado"), which is 99.8% owned by Pony Express. The remaining 0.2% interest in Tallgrass Colorado is held by direct and indirect wholly owned subsidiaries of TEP. Tallgrass Colorado was formed for the purpose of the potential construction of a lateral pipeline that would interconnect with the Pony Express System's existing lateral in Northeast Colorado and has not yet commenced operations or generated any income. Accordingly, no provision for federal or state income taxes has been recorded in the financial statements of TEP.

Accounting Pronouncements Issued But Not Yet Effective

Accounting Standards Update ("ASU") No. 2014-09, "Revenue from Contracts with Customers (Topic 606)"

In May 2014, the Financial Accounting Standards Board ("FASB") issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606). ASU 2014-09 provides a comprehensive and converged set of principles-based revenue recognition guidelines which supersede the existing industry and transaction-specific standards. The core principle of the new guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, entities must apply a five step process to (1) identify the contract with a customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation. ASU 2014-09 also mandates disclosure of sufficient information to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The disclosure requirements include qualitative and quantitative information about contracts with customers, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract.

The amendments in ASU 2014-09 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. Early application is permitted for annual reporting periods beginning after December 15, 2016. We are currently evaluating the impact of ASU 2014-09.

ASU No. 2014-12, "Compensation - Stock Compensation (Topic 718), Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period"

In June 2014, the FASB issued ASU No. 2014-12, Compensation - Stock Compensation (Topic 718), Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. ASU 2014-12 provides explicit guidance on accounting for share-based payments requiring a specific performance target to be achieved in order for employees to become eligible to vest in the awards when that performance target may be achieved after the requisite service period for the award. The ASU requires that such performance targets be treated as a performance condition, and should not be reflected in the estimate of the grant-date fair value of the award. Instead, compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved.

ASU 2014-12 is effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Early adoption is permitted. The adoption of ASU 2014-12 is not expected to have a material impact on our financial position and results of operations.

ASU No. 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis"

In February 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810) - Amendments to the Consolidation Analysis. ASU 2015-02 will change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. ASU 2015-02 will modify the evaluation of whether limited partnerships and other similar legal entities are considered VIEs or voting interest entities, eliminate the presumption that a general partner should consolidate a limited partnership, and change certain aspects of the consolidation analysis for reporting entities that are involved with VIEs, particularly for those with fee arrangements and related party relationships.

The amendments in ASU 2015-02 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2015. Early application is permitted, including adoption in an interim period. The adoption of ASU 2015-02 is not expected to have a material impact on our financial position and results of operations.

ASU No. 2015-11, "Inventory (Topic 330): Simplifying the Measurement of Inventory"

In July 2015, the FASB issued ASU No. 2015-11, Inventory (Topic 330), Simplifying the Measurement of Inventory. ASU 2015-11 establishes a "lower of cost and net realizable value" model for the measurement of most inventory balances. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation.

The amendments in ASU 2015-11 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2016. Early adoption is permitted. We are currently evaluating the impact of ASU 2015-11.

ASU No. 2015-16, "Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments"

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments. ASU 2015-16 simplifies the accounting for measurement-period adjustments for provisional amounts recognized in a business combination by eliminating the requirement for an acquirer to retrospectively account for measurement-period adjustments. Under the updated guidance, the acquirer must recognize adjustments in the reporting period in which the adjustment amounts are determined and the effect on earnings as a result of the change to the provisional amounts must be calculated as if the accounting had been completed at the acquisition date.

The amendments in ASU 2015-16 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2015. Early adoption is permitted, and must be applied prospectively. We are currently evaluating the impact of ASU 2015-16.

3. Variable Interest Entities

TEP does not have the obligation to absorb expected losses from Pony Express as a result of the minimum quarterly preference payments as discussed in Note 4 – *Acquisitions*. In addition, for the period from our acquisition of the initial 33.3% membership interest effective September 1, 2014 to our acquisition of an additional 33.3% membership interest effective March 1, 2015, TEP, as the managing member of Pony Express, had voting rights disproportionate to its ownership interest. As a result, we determined that Pony Express is a VIE of which TEP is the primary beneficiary and consolidated Pony Express accordingly.

We have not provided any additional financial support to Pony Express other than our initial capital contribution of $570 million and our pro rata portion of expansion capital projects as discussed below, and have no contractual commitments or obligations to provide additional financial support. In the event that the costs of construction of the Pony Express System, including the lateral in Northeast Colorado, exceed the $270 million retained by Pony Express as discussed in Note 4 – *Acquisitions*, TD is obligated to fund the remaining costs. As of December 31, 2015, the costs to complete construction have exceeded the amount retained, and as such TD will continue to fund any remaining costs associated with construction of the mainline and lateral in Northeast Colorado. Although TEP has no obligation to provide further financial support to Pony Express, expansion capital projects are funded by TEP and TD on a pro rata basis in accordance with the Pony Express LLC Agreement. Contributions from TEP to Pony Express to fund expansion capital projects totaled $4.4 million for the year ended December 31, 2015.

As discussed in Note 20 – *Subsequent Events*, TEP acquired an additional 31.3% membership interest in Pony Express effective January 1, 2016.

The carrying amounts and classifications of the Pony Express assets and liabilities included in TEP's consolidated balance sheet at December 31, 2015 and December 31, 2014 are as follows:

	December 31, 2015	December 31, 2014
	(in thousands)	
Current assets	$ 46,800	$ 93,019
Noncurrent assets	1,391,906	1,300,816
Total assets	$ 1,438,706	$ 1,393,835
Current liabilities	$ 51,349	$ 52,547
Total liabilities	$ 51,349	$ 52,547

4. Acquisitions

TEP Acquisition of Trailblazer

On April 1, 2014, TEP closed the acquisition of Trailblazer from a wholly owned subsidiary of TD for total consideration valued at approximately $164 million, consisting of $150 million in cash and the issuance of 385,140 common units (valued at approximately $14 million based on the March 31, 2014 closing price of TEP's common units). On that same date, the general partner contributed additional capital in the amount of approximately $263,000 in exchange for the issuance of 7,860 general partner units in order to maintain its 2% general partner interest. The acquisition of Trailblazer represents a change in reporting entity and a transaction between entities under common control. The excess purchase price over the net book value of Trailblazer's assets and liabilities was accounted for as a deemed distribution as discussed further in Note 11 – *Partnership Equity and Distributions*.

TEP Acquisitions of 66.7% of Pony Express

Effective September 1, 2014, TEP acquired a controlling 33.3% membership interest in Pony Express for total consideration of approximately $600 million. At closing, Pony Express, TD, and TEP entered into the Second Amended Pony Express LLC Agreement, which set forth the relative rights of TD and TEP as the owners of Pony Express. Of the total consideration of $600 million, TEP directly paid TD $30 million, consisting of $27 million in cash and 70,340 TEP common units with an aggregate fair value of approximately $3 million, in exchange for the transfer by TD to TEP of a 1.9585% membership interest in Pony Express (computed before giving effect to the issuance of the new membership interest by Pony Express to TEP). TEP also contributed cash of $570 million to Pony Express in exchange for a newly issued membership interest which, when combined with the membership interest transferred from TD and the parties' entry at closing into the Second Amended Pony Express LLC Agreement, constituted TEP's 33.3% membership interest in Pony Express, which represented 100% of the preferred membership units issued by Pony Express. Of the $570 million cash consideration received by Pony Express, $300 million was immediately distributed to TD at closing and $270 million was retained by Pony Express to fund the estimated remaining costs of construction for the Pony Express System and the lateral in Northeast Colorado. The $270 million cash balance was subsequently swept to TD under a cash management agreement between Pony Express and TD and was recorded as a related party loan which bears interest at TD's incremental borrowing rate. There was no remaining balance outstanding on the related party loan at December 31, 2015.

The terms of TEP's first acquisition of a 33.3% membership interest in Pony Express provided TEP a minimum quarterly preference payment of $16.65 million through the quarter ended September 30, 2015 (prorated to approximately $5.4 million for the quarter ended September 30, 2014) with distributions thereafter shared in accordance with the terms of the Second Amended Pony Express LLC Agreement. At the effective date of that transaction, TEP determined that Pony Express was a VIE of which TEP was the primary beneficiary, and consolidated Pony Express accordingly. For additional discussion and disclosure, see Note 3 – *Variable Interest Entities*. The acquisition of the initial 33.3% membership interest in Pony Express represented a transaction between entities under common control and a change in reporting entity.

Effective March 1, 2015, TEP acquired an additional 33.3% membership interest in Pony Express for cash consideration of $700 million. At closing, Pony Express, TD, and TEP entered into the Pony Express LLC Agreement, which sets forth the relative rights of TD and TEP as the owners of Pony Express. The terms of the transaction increased the minimum quarterly preference payment provided to TEP to $36.65 million through the quarter ending December 31, 2015 (prorated to approximately $23.5 million for the quarter ended March 31, 2015) with distributions thereafter shared in accordance with the terms of the Pony Express LLC Agreement.

Upon the effective date of the second acquisition, TEP reevaluated its VIE assessment and determined that Pony Express continued to be considered a VIE of which TEP is the primary beneficiary. The acquisition of the additional 33.3% membership interest in Pony Express represents a transaction between entities under common control and an acquisition of noncontrolling interests. As a result, financial information for periods prior to the transaction have not been recast to reflect the additional 33.3% membership interest.

As discussed in Note 20 – *Subsequent Events*, effective January 1, 2016 TEP acquired an additional 31.3% membership interest in Pony Express.

Formation of BNN Water Solutions, LLC

On November 26, 2013, TEP, through its wholly-owned subsidiary Tallgrass Energy Investments, LLC ("TEI"), entered into a joint venture agreement with BNN Energy LLC ("BNN") to form GWSI, which subsequently built and began operating an intrastate fresh water pipeline in Colorado. TEP accounted for its 50% equity interest in GWSI as an equity method investment. On May 13, 2014, TEI entered into a contribution agreement with BNN and several other parties to form a new entity known as Water Solutions. Under the terms of the contribution agreement, TEI agreed to contribute its existing 50% interest in GWSI, along with $7.6 million cash, in exchange for an 80% membership interest in Water Solutions. As part of the transaction, GWSI was renamed Redtail, became a subsidiary of Water Solutions, and issued preferred equity interests to TEI. Among the assets contributed by BNN and the other parties to the transaction were the other 50% interest in Redtail and a 100% equity interest in Alpha Reclaim Technology, LLC ("Alpha"), a company which sources treated wastewater from municipalities in Texas. Alpha is wholly-owned by Redtail.

Upon closing of the transaction, TEP obtained a controlling financial interest in Water Solutions and accordingly has accounted for the transaction as a step acquisition under ASC 805. On the acquisition date, TEP remeasured its previously held 50% equity interest in Redtail to its fair value of $11.9 million, recognized a gain of $9.4 million, and consolidated Water Solutions. The 20% equity interest in Water Solutions held by noncontrolling interests was recorded at its acquisition date fair value of $1.4 million. The fair values of the previously held equity interest and the noncontrolling interest were determined using a discounted cash flow analysis. These fair value measurements are based on significant inputs that are not observable in the market and thus represent fair value measurements categorized within Level 3 of the fair value hierarchy under ASC 820.

At December 31, 2014, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. During the three months ended June 30, 2015, the preliminary purchase price allocation with respect to Water Solutions was finalized with no material adjustments.

On May 20, 2015, TEP acquired an additional 12% equity interest in Water Solutions from NR2, LLC for cash consideration of $600,000, which was accounted for as an acquisition of noncontrolling interest. As of December 31, 2015, TEP's aggregate membership interest in Water Solutions was 92%.

TEP Acquisition of BNN Western, LLC

On December 16, 2015, Whiting Oil and Gas Corporation ("Whiting"), Redtail, and BNN Western, LLC ("Western"), a newly formed Delaware limited liability company, entered into a definitive Transfer, Purchase and Sale Agreement, pursuant to which Redtail acquired 100% of the outstanding membership interests of Western from Whiting in exchange for total cash consideration of $75 million. Western's assets consist of a fresh water delivery and storage system and produced water gathering and produced water disposal system, which together comprise 62 miles of pipeline along with associated fresh water ponds and disposal wells. The purchase agreement with Whiting includes a five-year fresh water service contract and a nine-year gathering and disposal contract.

At December 31, 2015, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. The $75 million purchase price of the assets was allocated entirely to property, plant and equipment. TEP is in the process of obtaining additional information to identify and measure all assets acquired and liabilities assumed in the acquisition within the measurement period. Such provisional amounts will be adjusted if necessary to reflect any new information about facts and circumstances that existed at the acquisition date that, if known, would have affected the measurement of these amounts.

Actual revenue and net income attributable to TEP from Western of $0.3 million and $0.1 million, respectively, was recognized in the accompanying consolidated statements of income for the period from December 16, 2015 to December 31, 2015.

Unaudited pro forma revenue and net income attributable to partners for the years ended December 31, 2015 and 2014 is presented below as if the acquisition of Western had been completed on January 1, 2014:

	Year Ended December 31,	
	2015	2014
	(in thousands)	
Revenue	538,033	373,470
Net income attributable to partners	161,184	71,347

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 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. The pro forma revenue and net income includes adjustments to give effect to TEP's consolidated interest in the estimated results of operations of Western for the periods presented.

5. Related Party Transactions

We have no employees. TD, through its wholly-owned subsidiary Tallgrass Operations, LLC ("Tallgrass Operations"), provided and charged us for direct and indirect costs of services provided to us or incurred on our behalf including employee labor costs, information technology services, employee health and retirement benefits, and all other expenses necessary or appropriate to the conduct of our business. We recorded these costs on the accrual basis in the period in which TD incurred them. On May 17, 2013, in connection with the closing of TEP’s initial public offering, TEP and its general partner entered into an Omnibus Agreement with TD and certain of its affiliates, including Tallgrass Operations (the "TEP Omnibus Agreement"). The TEP Omnibus Agreement provides that, among other things, TEP will reimburse TD and its affiliates for all expenses they incur and payments they make on TEP’s 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.

TEP's general and administrative costs under the TEP Omnibus Agreement were $21.5 million for the year ended December 31, 2015, excluding costs attributable to Pony Express. Pony Express had general and administrative costs under the TEP Omnibus Agreement of $20.6 million for the year ended December 31, 2015. TEP also pays a quarterly reimbursement to TD for costs associated with being a public company, which was $2.5 million for the year ended December 31, 2015. These amounts will be periodically reviewed and adjusted as necessary to continue to reflect reasonable allocation of costs to TEP.

Due to the cash management agreement discussed in Note 2 – *Summary of Significant Accounting Policies*, intercompany balances at the Predecessor Entities were periodically settled and treated as equity distributions prior to the completion of the IPO on May 17, 2013, prior to April 1, 2014 for Trailblazer, and prior to September 1, 2014 for Pony Express. Balances lent to TD under the Pony Express cash management agreement effective September 1, 2014 are classified as related party receivables in the consolidated balance sheets. During the years ended December 31, 2015 and 2014 we recognized interest income from TD of $0.4 million and $1.5 million, respectively, on the receivable balance under the Pony Express cash management agreement.

Totals of transactions with affiliated companies are as follows:

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Cost of transportation services (1)	$ 25,046	$ —	$ —
Charges to TEP: (2)			
Property, plant and equipment, net	$ 4,320	$ 17,936	$ 7,604
Other deferred charges	$ 7	$ 27	$ 799
Operation and maintenance	$ 23,520	$ 18,783	$ 18,439
General and administrative	$ 33,432	$ 23,475	$ 20,140

(1) Reflects rent expense under operating lease agreements that primarily consist of crude oil storage capacity leased by Pony Express from Deeprock Development, LLC ("Deeprock"), an unconsolidated affiliate of TD, and Tallgrass Sterling Terminal, LLC ("Sterling"), a consolidated subsidiary of TD. For more information, see Note 12 – *Commitments & Contingent Liabilities*.

(2) Charges to TEP, inclusive of Pony Express, include directly charged wages and salaries, other compensation and benefits, and shared services.

Details of balances with affiliates included in "Receivable from related parties" and "Accounts payable to related parties" in the consolidated balance sheets are as follows:

	December 31, 2015	December 31, 2014
	(in thousands)	
Receivables from related parties:		
Tallgrass Operations, LLC	$ —	$ 73,393
Rockies Express Pipeline LLC	15	—
Total receivables from related parties	$ 15	$ 73,393
Accounts payable to related parties:		
Tallgrass Operations, LLC	$ 7,792	$ 3,894
Tallgrass Equity, LLC	36	—
Deeprock Development, LLC	17	—
Rockies Express Pipeline LLC	7	21
Total accounts payable to related parties	$ 7,852	$ 3,915

Balances of gas imbalances with affiliated shippers are as follows:

	December 31, 2015	December 31, 2014
	(in thousands)	
Affiliate gas balance receivables	$ 92	$ 275
Affiliate gas balance payables	$ 227	$ 455

Pursuant to the terms of a Purchase and Sale Agreement dated August 1, 2012, TD, through August 31, 2014, reimbursed TIGT for all costs TIGT incurred with respect to the Pony Express Abandonment, as defined in Note 16 – *Regulatory Matters*, including, but not limited to, development costs, capital costs and related interest costs associated with 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 in order for TIGT to continue service to existing customers after having sold approximately 433 miles of natural gas pipeline, and associated rights of way and certain other equipment, to Pony Express in 2013. For more information, see Note 16 – *Regulatory Matters*. Any costs incurred by TIGT subsequent to August 31, 2014 are reimbursed directly by Pony Express.

TIGT's expenditures for the Replacement Gas Facilities are captured in "Prepayments and other current assets" in the consolidated balance sheets as they are incurred and interest is accrued until reimbursement takes place (which is typically monthly). During the year ended December 31, 2014 we received proceeds from TD of $69.2 million and incurred expenditures of $41.7 million. We recognized a contribution of $27.5 million from TD in our Consolidated Statement of Partners' Capital which represents the difference between the carrying amount of the Replacement Gas Facilities and the proceeds received from TD. At December 31, 2015 and 2014, TEP had not incurred any expenditures for the Replacement Gas Facilities that had not been reimbursed. 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. At December 31, 2013, TEP had $17.0 million in "Prepayments and other current assets" related to this project that were cash settled by TD in the first quarter of 2014.

6. Inventory

The components of inventory at December 31, 2015 and December 31, 2014 consisted of the following:

	December 31, 2015	December 31, 2014
	(in thousands)	
Crude oil	$ 2,661	$ 581
Materials and supplies	8,581	3,049
Natural gas liquids	395	519
Gas in underground storage	2,156	8,896
Total inventory	$ 13,793	$ 13,045

In July 2014, Pony Express entered into an agreement with Shell Trading (US) Company ("Shell") for the purchase of 800,000 barrels of crude oil that was available for initial line fill on the Pony Express System, which was subsequently sold back to Shell in November 2014. To support the resale obligation of Pony Express, in July 2014 TD paid Shell a deposit of $20 million and issued a letter of credit for $20 million and a parent guarantee of $40 million to Shell on behalf of Pony Express. TEP returned the barrels to Shell in November 2014. At that time, the letter of credit was cancelled and Shell returned the $20 million deposit to Pony Express, which Pony Express subsequently returned to TD.

7. Property, Plant and Equipment

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

	December 31, 2015	December 31, 2014
	(in thousands)	
Crude oil pipelines	$ 1,172,684	$ 939,536
Natural gas pipelines	550,710	548,482
Processing and treating assets	254,073	237,218
Water business assets	81,098	4,453
General and other	69,181	42,719
Construction work in progress	30,699	139,873
Accumulated depreciation and amortization	(133,427)	(59,200)
Total property, plant and equipment, net	$ 2,025,018	$ 1,853,081

Depreciation expense was approximately $75.5 million, $40.9 million, and $36.6 million for the years ended December 31, 2015, 2014, and 2013, respectively. Capitalized interest was approximately $0.9 million, $1.2 million, and $0.9 million for the years ended December 31, 2015, 2014, and 2013, respectively.

Under a lease agreement effective October 3, 2015, TMID, as lessor, leases capacity on an NGL pipeline that was constructed for a third party. Rental income was approximately $0.8 million for the year ended December 31, 2015, and was recorded as "Processing and other revenues" in the accompanying consolidated statements of income. Under a lease agreement initially effective November 13, 2012, TIGT, as lessor, leases a portion of its office space to a third party. Rental income was approximately $0.8 million, $1.0 million, and $1.0 million for the years ended December 31, 2015, 2014, and 2013, respectively, and was recorded as "Other income, net" in the accompanying consolidated statements of income. As of December 31, 2015, future minimum rental income under non-cancelable operating leases as the lessor were as follows (in thousands):

Year	Total
2016	$ 3,952
2017	3,967
2018	3,982
2019	3,997
2020	3,385
Thereafter	15,114
Total	$ 34,397

8. Goodwill and Other Intangible Assets

Reconciliation of Goodwill

The following table presents a reconciliation of the carrying amount of goodwill by reportable segment for the reporting period:

	Year Ended December 31, 2015			Year Ended December 31, 2014		
	Natural Gas Transportation & Logistics	Processing & Logistics	Total	Natural Gas Transportation & Logistics	Processing & Logistics	Total
	(in thousands)			(in thousands)		
Balance at beginning of period	$ 255,558	$ 87,730	$ 343,288	$ 255,558	$ 79,157	$ 334,715
Goodwill acquired	—	—	—	—	8,573 (1)	8,573
Balance at end of period	$ 255,558	$ 87,730	$ 343,288	$ 255,558	$ 87,730	$ 343,288

(1) The $8.6 million of goodwill was recorded in connection with the acquisition of a controlling interest in Water Solutions on May 13, 2014.

Annual Goodwill Impairment Analysis

We did not elect to apply the qualitative assessment option during our 2015 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 purpose 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. Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. 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 greater than their respective book values. Fair value exceeded the book value by at least 10% for each of the reporting units. 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 2015. Unpredictable events or deteriorating market or operating conditions could result in a future change to the discounted cash flow models and potential future impairments. We continue to monitor potential impairment indicators, including declines in our market price, to determine if a triggering event occurs and will perform additional goodwill impairment analyses as necessary.

As a result of a decreased commodity prices in late 2015 and into early 2016, which caused a significant drop in the volumes anticipated from several producers from which TMID receives natural gas for processing, we identified a potential impairment trigger with respect to the $79.2 million of goodwill at the TMID reporting unit, which is a component of our Processing & Logistics segment. We tested TMID's goodwill for impairment as of December 31, 2015 and determined that the fair value of the reporting unit exceeds the carrying value by approximately 21%. As a result, no impairment charge was recorded, however our analysis includes assumptions of a gradual recovery of commodity prices and a corresponding increase in volumes over time. If our outlook for long-term commodity prices is not realized, or our producers further decrease volumes, we could have an impairment in the future.

Other Intangible Assets

A summary of amortized intangible assets is as follows:

	December 31, 2015	December 31, 2014
	(in thousands)	
Pony Express oil conversion use rights	$ 105,973	$ 105,973
Redtail customer contract [1]	—	8,200
Accumulated amortization	(9,427)	(9,635)
Intangible assets, net	$ 96,546	$ 104,538

[1] The Redtail customer contract was fully amortized as of December 31, 2015.

Amortization of intangible assets was approximately $8.0 million, $6.2 million, and $3.0 million for the years ended December 31, 2015, 2014, and 2013, respectively.

Estimated future amortization for these intangible assets is as follows (in thousands):

Year	Total
2016	$ 3,028
2017	3,028
2018	3,028
2019	3,028
2020	3,028
Thereafter	81,406
Total	$ 96,546

9. Risk Management

We occasionally enter into derivative contracts with third parties for the purpose of hedging exposures that accompany our normal business activities. Our normal business activities directly and indirectly expose us to risks associated with changes in the market price of crude oil and natural gas, among other commodities. For example, 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. We have elected not to apply hedge accounting and changes in the fair value of all derivative contracts are recorded in earnings in the period in which the change occurs. As of December 31, 2015 and December 31, 2014, we had no derivative contracts outstanding.

Effect of Derivative Contracts on the Income Statement

The following tables summarize the impact of derivative contracts for the years ended December 31, 2015, 2014 and 2013:

	Location of gain (loss) recognized in income on derivatives	Amount of gain (loss) recognized in income on derivatives Year Ended December 31, 2015	2014	2013
			(in thousands)	
Derivatives not designated as hedging contracts:				
Energy commodity derivative contracts	Natural gas sales	$ 427	$ (410)	$ (548)

Fair Value

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

OTC derivatives are valued using models utilizing a variety of inputs including contractual terms and commodity and interest rate curves. 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. We use similar models to value similar instruments. For OTC derivative contracts that trade in liquid markets, such as generic forwards and swaps, model inputs can generally be verified and model selection does not involve significant management judgment. Such contracts are typically classified within Level 2 of the fair value hierarchy.

Certain OTC derivative contracts trade in less liquid markets with limited pricing information; as such, 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 our 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. As of December 31, 2015 and December 31, 2014, we had no derivative contracts outstanding.

10. Long-term Debt

Revolving Credit Facility

On May 17, 2013, in connection with the IPO, TEP entered into a senior secured revolving credit facility with Barclays Bank PLC, as administrative agent, and a syndicate of lenders ("the Credit Agreement"), which will mature on May 17, 2018. On June 25, 2014, TEP and certain of its subsidiaries entered into Amendment No. 1 to the Credit Agreement. On November 24, 2015, TEP and certain of its subsidiaries entered into Amendment No. 2 to the Credit Agreement, which modified certain provisions of the Credit Agreement to increase the amount of the revolving facility from $850 million to $1.1 billion and provide for a committed accordion in an amount up to an additional $400 million, subject to the satisfaction of certain other conditions. The revolving credit facility includes a $75 million sublimit for letters of credit and a $60 million sublimit for swing line loans. As discussed in Note 20 – *Subsequent Events*, effective January 4, 2016, in connection with the acquisition of an additional 31.3% membership interest in Pony Express, TEP exercised the committed accordion feature to increase the total capacity of the revolving credit facility to $1.5 billion. As of January 31, 2016, TEP had approximately $1.2 billion of outstanding borrowings under its revolving credit facility.

The following table sets forth the available borrowing capacity under our revolving credit facility as of December 31, 2015 and December 31, 2014:

	December 31, 2015	December 31, 2014
	(in thousands)	
Total capacity under the revolving credit facility	$ 1,100,000	$ 850,000
Less: Outstanding borrowings under the revolving credit facility	(753,000)	(559,000)
Available capacity under the revolving credit facility	$ 347,000	$ 291,000

The revolving 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 making such a distribution), 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." In addition, we are required 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. As of December 31, 2015, we are in compliance with the covenants required under the revolving credit facility.

The unused portion of the revolving credit facility is subject to a commitment fee, which ranges from 0.300% to 0.500%, based on our total leverage ratio. As of December 31, 2015, the weighted average interest rate on outstanding borrowings was 2.08%.

Fair Value

The following table sets forth the carrying amount and fair value of our long-term debt, which is not measured at fair value in the consolidated balance sheets as of December 31, 2015 and 2014, 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, 2015	$ —	$ 753,000	$ —	$ 753,000	$ 753,000
December 31, 2014	$ —	$ 559,000	$ —	$ 559,000	$ 559,000

The long-term debt borrowed under the revolving credit facility is carried at amortized cost. As of December 31, 2015 and December 31, 2014, the fair value approximates the carrying amount for the borrowings under the revolving credit facility using a discounted cash flow analysis. We are not aware of any factors that would significantly affect the estimated fair value subsequent to December 31, 2015.

11. Partnership Equity and Distributions

Public Offerings

On February 27, 2015, we sold 10,000,000 common units representing limited partner interests in an underwritten public offering at a price of $50.82 per unit, or $49.29 per unit net of the underwriter's discount, for net proceeds of approximately $492.4 million after deducting the underwriter's discount and offering expenses. We used the net proceeds from the offering to fund a portion of the consideration for the acquisition of an additional 33.3% membership interest in Pony Express as discussed in Note 4 – *Acquisitions*. Pursuant to the underwriters' option to purchase additional units, we sold an additional 1,200,000 common units representing limited partner interests to the underwriters at a price of $50.82 per unit, or $49.29 per unit net of the underwriter’s discount, for net proceeds of approximately $59.3 million after deducting the underwriter’s discount and offering expenses. We used the net proceeds from this additional purchase of common units to reduce borrowings under our revolving credit facility, a portion of which were used to fund the March 2015 acquisition of an additional 33.3% membership interest in Pony Express as discussed in Note 4 – *Acquisitions*.

On July 25, 2014, we sold 8,050,000 common units representing limited partner interests in an underwritten public offering at a price of $41.07 per unit, or $39.74 per unit net of the underwriter's discount, for net proceeds of approximately $319.3 million after deducting the underwriter's discount and offering expenses. We used the net proceeds from the offering to fund a portion of the consideration for the acquisition of the initial 33.3% membership interest in Pony Express as discussed in Note 4 – *Acquisitions*.

Equity Distribution Agreement

On October 31, 2014, we entered into an equity distribution agreement pursuant to which we may sell from time to time through a group of managers, as our sales agents, common units representing limited partner interests having an aggregate offering price of up to $200 million. On May 13, 2015 the amount was subsequently amended to $100.2 million in order to account for follow-on equity offerings under our S-3 shelf registration statement. Sales of the common units, if any, will be made by means of ordinary brokers’ transactions, to or through a market maker or directly on or through an electronic communication network, a "dark pool" or any similar market venue, or as otherwise agreed by the Partnership and one or more of the managers. We intend to use the net proceeds from any sale of the units for general partnership purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.

During the year ended December 31, 2015, we issued and sold 65,744 common units with a weighted average sales price of $45.58 per unit under our equity distribution agreement for net proceeds of approximately $3.0 million (net of approximately $30,000 in commissions and professional service expenses). We used the net proceeds for general partnership purposes. At December 31, 2015, approximately $95.9 million in aggregate offering price remained available to be issued and sold under the equity distribution agreement.

During the year ended December 31, 2014, we issued and sold 28,625 common units with a weighted average sales price of $44.20 per unit under our equity distribution agreement for net proceeds of approximately $1.1 million (net of approximately $215,000 in commissions and professional service expenses). We used the net proceeds for general partnership purposes.

Distributions to Holders of Common Units, Subordinated Units, General Partner Units and Incentive Distribution Rights

Our partnership agreement requires us to distribute our available cash, as defined generally below, to unitholders of record on the applicable record date within 45 days after the end of each quarter. Our 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 our partnership agreement as the minimum quarterly distribution ("MQD").

The following table shows the distributions for the periods indicated:

Three Months Ended	Date Paid	Distributions				Distribution per Limited Partner Common and Subordinated Unit
		Limited Partner Common and Subordinated Units	General Partner		Total	
			Incentive Distribution Rights	General Partner Units		
		(in thousands, except per unit amounts)				
December 31, 2015....	February 12, 2016.....	$ 42,984	$ 15,332	$ 724	$ 59,040	$ 0.6400
September 30, 2015...	November 13, 2015 ..	36,347	11,567	660	48,574	0.6000
June 30, 2015............	August 14, 2015.......	35,135	10,418	627	46,180	0.5800
March 31, 2015.........	May 14, 2015...........	31,322	6,934	530	38,786	0.5200
December 31, 2014....	February 13, 2015.....	23,782	4,039	473	28,294	0.4850
September 30, 2014...	November 14, 2014 ..	20,092	1,208	363	21,663	0.4100
June 30, 2014............	August 14, 2014.......	18,596	758	330	19,684	0.3800
March 31, 2014.........	May 14, 2014...........	13,288	126	274	13,688	0.3250
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............	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 the MQD of $0.2875 per common unit, based upon the number of days between the closing of the IPO on May 17, 2013 and June 30, 2013.

Subordinated Units

Under the terms of TEP's partnership agreement and upon the payment of the quarterly cash distribution to unitholders on February 13, 2015, the subordination period ended. As a result, the 16,200,000 subordinated units then held by TD converted into common units on a one for one basis on February 17, 2015.

General Partner Units

As of December 31, 2015, the general partner owns an approximate 1.36% general partner interest in TEP, represented by 834,391 general partner units. Under TEP's partnership agreement, the general partner may at any time, but is under no obligation to, contribute additional capital to TEP in order to maintain or attain a 2% general partner interest.

Incentive Distribution Rights

The general partner also owns all of the 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 each target distribution level has been achieved. The general partner may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

The following discussion related to incentive distributions assumes that our general partner holds a 2% general partner interest and continues to own all of the IDRs.

If for any quarter:

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

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

- *first*, 98% to all unitholders, pro rata, and 2% to our 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 our 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 our 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 our 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 our general partner to:
  - provide for the proper conduct of our business (including reserves for 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);
  - comply with applicable law or regulation, or any of our debt instruments or other agreements; or
  - provide funds for distributions to unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the MQD on all common units and any cumulative arrearages on such common units for the current quarter);
- *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.

Other Contributions and Distributions

During the year ended December 31, 2015, TEP was deemed to have made a noncash capital distribution of $324.3 million to the general partner, which represents the excess purchase price over the carrying value of the additional 33.3% membership interest in Pony Express acquired effective March 1, 2015. See Note 4 – *Acquisitions* for additional information regarding the transaction. We also recognized contributions from noncontrolling interests of $110.1 million, which consisted primarily of contributions from TD to Pony Express to fund construction of the lateral in Northeast Colorado, and distributions to noncontrolling interests of $69.5 million, which consisted primarily of distributions from Pony Express to TD.

During the year ended December 31, 2014, we received net contributions of $312.1 million, $27.5 million, and $5.4 million from the Predecessor Entities, TD, and noncontrolling interests, respectively. Net contributions of $312.1 million from the Predecessor Entities is composed of net contributions of $612.1 million relating to the cash management agreements with TD, as well as a cash distribution of $300 million of the proceeds from the issuance of the preferred membership interest to TEP from Pony Express to TD pursuant to the Pony Express Contribution and Sale Agreement. As discussed in Note 2 – *Summary of Significant Accounting Policies*, prior to May 17, 2013 for TIGT and TMID, prior to April 1, 2014 for Trailblazer, and prior to September 1, 2014 for Pony Express, the net amount of transfers for loans made each day through the centralized cash management system with TD, less reimbursement payments under the agency agreement described in Note 5 – *Related Party Transactions*, was recognized as net equity contributions or distributions during that time period. There were no equity contributions or distributions made to TD subsequent to Trailblazer's acquisition by TEP on April 1, 2014 or the acquisition of Pony Express effective September 1, 2014. The $27.5 million contribution from TD represents the difference between the carrying amount of the Replacement Gas Facilities and the proceeds received from TD, as discussed in Note 5 – *Related Party Transactions*. The $5.4 million contribution from noncontrolling interests represents the cash contributed to Pony Express from TD to fund the quarterly preference payment to TEP as discussed in Note 4 – *Acquisitions*. During the year ended December 31, 2014, Pony Express made a distribution of $5.4 million to TD, which was settled via the Pony Express cash management agreement.

During the year ended December 31, 2014, TEP was deemed to have made a noncash, net capital distribution of $72.9 million to the general partner, which represents the excess purchase price over the carrying value of the Trailblazer net assets acquired on April 1, 2014. Also during the year ended December 31, 2014, TEP was deemed to have made a capital distribution of $8.7 million to the general partner, which represents the excess purchase price, consisting of $27 million in cash and limited partner common units valued at $3.0 million issued directly to TD, over the net book value of the 1.9585% membership interest in Pony Express transferred from TD to TEP in accordance with the Pony Express Contribution and Sale Agreement. See Note 4 – *Acquisitions* for additional information regarding the Trailblazer and Pony Express acquisitions.

During the year ended December 31, 2013, net distributions from TEP Predecessor to TD were approximately $118.5 million, and included the $85.5 million cash distribution 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. During the year ended December 31, 2013, the Predecessor Entities recognized net contributions from TD of $379.9 million.

12. Commitments & Contingent Liabilities

Leases

Rent expense under operating leases and right of way agreements totaled approximately $25.8 million, $4.7 million, and $327,000 for the years ended December 31, 2015, 2014, and 2013, respectively.

At December 31, 2015, future minimum rental commitments under major, non-cancelable operating leases were as follows (in thousands):

Year	Total
2016	$ 27,805
2017	28,355
2018	28,714
2019	29,246
2020	29,879
Thereafter	478,550
Total	$ 622,549

Operating lease agreements primarily consist of storage capacity leased by Pony Express from Deeprock, an unconsolidated affiliate of TD and Sterling, an indirect wholly-owned subsidiary of TD.

Pony Express entered into a lease agreement with Deeprock on November 7, 2012 for the use by Pony Express of storage capacity at the Deeprock tank storage facility near Cushing, Oklahoma. The lease has a five year term which commenced on October 7, 2014. Pony Express made upfront payments totaling $10.9 million, of which $4.6 million was paid in 2013 and $6.3 million was paid in 2014. The upfront payments are recorded as "Deferred charges and other assets" on the accompanying consolidated balance sheets and will be amortized over the lease term. Pony Express has the right to extend the term of the lease for additional periods of five or two years, not to exceed a total of 20 years from when the lease commences. Future minimum rental commitments in the table above assume renewal of the Deeprock lease for the full 20 year term as the storage capacity at Deeprock is integral to the operations of the Pony Express System and renewal of the lease is reasonably assured as a result.

On August 26, 2014, Pony Express entered into a lease agreement with Sterling for the use by Pony Express of storage capacity at the Sterling tank storage facility in northeast Colorado. The lease has a five year term which commenced on May 1, 2015. Pony Express has the right to extend the term of the lease for additional periods of five years, not to exceed a total of 20 years from the commencement of the lease agreement. Future minimum rental commitments in the table above assume renewal of the Sterling lease for the full 20 year term as the storage capacity at Sterling is integral to the operations of the lateral in Northeast Colorado and renewal of the lease is reasonably assured as a result.

Capital Expenditures

We had committed approximately $5.8 million for the future purchase of property, plant and equipment at December 31, 2015.

13. 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. As discussed in Note 11 – *Partnership Equity and Distributions*, the subordinated units were converted to common units effective February 17, 2015.

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 (which are currently held by our general partner), even though we make 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. 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 or predecessor operations. All net income or loss from Trailblazer prior to its acquisition on April 1, 2014 and Pony Express prior to its acquisition effective September 1, 2014 is allocated to predecessor operations in the table below. Historical earnings of transferred businesses for periods prior to the date of those common control drop-down transactions are solely those of the general partner and, therefore we have appropriately excluded any allocation to the limited partner units when determining net income available to common and subordinated unitholders. We present the financial results of any transferred business prior to the drop down transaction date in the line item "Predecessor operations interest in net (income) loss" in the table below.

The following table illustrates the Partnership's calculation of net income per common and subordinated unit for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31, 2015	Year Ended December 31, 2014	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	$ 184,814	$ 59,329	$ 7,624	$ 5,049	$ 2,575
Net (income) loss attributable to noncontrolling interests	(24,268)	11,352	2,123	761	1,362
Net income attributable to partners	160,546	70,681	9,747	5,810	3,937
Predecessor operations interest in net (income) loss	—	(1,508)	4,432	1,172	3,260
General partner interest in net income	(46,478)	(7,399)	(7,188)	(6,982)	(206)
Net income available to common and subordinated unitholders	$ 114,068	$ 61,774	$ 6,991	$ —	$ 6,991
Basic net income per common and subordinated unit	$ 1.95	$ 1.39	$ 0.17		$ 0.17
Diluted net income per common and subordinated unit	$ 1.91	$ 1.36	$ 0.17		$ 0.17
Basic average number of common and subordinated units outstanding	58,597	44,346	40,450		40,450
Equity Participation Unit equivalent units	978	1,048	1,008		1,008
Diluted average number of common and subordinated units outstanding	59,575	45,394	41,458		41,458

14. Major Customers and Concentration of Credit Risk

During the year ended December 31, 2015, two non-affiliated customers, Continental Resources and Shell, accounted for $84.5 million (16%) and $78.6 million (15%) of our total operating revenues, respectively. The revenues from Continental Resources were earned in our Crude Oil Transportation & Logistics, while the revenues from Shell were earned in both our Crude Oil Transportation & Logistics and Processing & Logistics segments. During the years ended December 31, 2014 and 2013 one non-affiliated customer, Phillips 66, accounted for $113.6 million (31%) and $102.0 million (35%) of our total operating revenues, respectively. All of the Phillips 66 revenues for 2014 and 2013 were earned in our Processing & Logistics segment.

For the year ended December 31, 2015, the percentage of segment revenues from the top ten non-affiliated customers for each segment was as follows:

	Percentage of Segment Revenue
Crude Oil Transportation & Logistics	96%
Natural Gas Transportation & Logistics	51%
Processing & Logistics	93%

We attempt to mitigate credit risk by seeking collateral or financial guarantees and letters of credit from customers with specific credit concerns. In support of credit extended to certain customers, we had received prepayments of $4.7 million and $3.1 million at December 31, 2015 and 2014, respectively, included in the caption "Other current liabilities" in the accompanying consolidated balance sheets.

15. Equity-Based Compensation

Long-term Incentive Plan

Effective May 13, 2013, the 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 the general partner.

The LTIP limits the number of units that may be delivered pursuant to vested awards to 10,000,000 common units. Common units canceled, 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 TEP's general partner or a committee thereof, which is referred 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, TEP's general partner approved the grant of up to 1.5 million equity participation units ("EPUs") for issuance to employees and 177,500 EPUs to certain Section 16 officers under the LTIP. Vesting of the EPUs granted to employees is contingent upon the mainline portion of the Pony Express System being placed into service and will generally occur in two parts, with one-third vesting on the later of the in-service date or May 13, 2015, and the remaining two-thirds vesting on the later of the in-service date or May 13, 2017. The mainline portion of the Pony Express System was placed in service in October 2014. Accordingly, one-third of these grants vested on May 13, 2015. New EPUs granted after the first quarter of 2014 will vest on terms and conditions as approved by the general partner or the plan administrator.

The EPU grants under the LTIP 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 was approximately $9.3 million, $10.2 million, and $4.2 million for the years ended December 31, 2015, 2014, and 2013, respectively. Of the total compensation cost, $5.1 million, $5.1 million, and $1.8 millions for the years ended December 31, 2015, 2014, and 2013, respectively, were recognized as compensation expense at TEP and the remainder was allocated to TD. As of December 31, 2015, $14.7 million of total compensation cost related to non-vested EPUs is expected to be recognized over a weighted average period of 2.2 years, a portion of which will be charged to TD.

The following table summarizes the changes in the EPUs outstanding for the year ended December 31, 2015:

	Year Ended December 31, 2015	
	Equity Participation Units	Weighted Average Grant Date Fair Value
Beginning of period	1,525,750	$ 18.75
Granted	338,591	40.01
Vested [(1)]	(480,555)	(19.39)
Forfeited	(58,825)	(16.98)
End of period	1,324,961	$ 24.11

(1) During the year ended December 31, 2015, approximately 344,383 common units (net of tax withholding of approximately 136,172 common units) were issued in connection with the settlement of vested awards.

16. Regulatory Matters

There are currently no proceedings challenging the currently effective rates of Pony Express or Trailblazer. On October 30, 2015, TIGT filed a general rate case with the FERC pursuant to Section 4 of the Natural Gas Act, discussed in more detail below. Regulators, as well as shippers, do have rights, under circumstances prescribed by applicable regulations, to challenge the rates that we charge at our regulated entities. Further, the statute governing service by Pony Express allows parties having standing to file complaints in regard to existing tariff rates and provisions. If the complaint is not resolved, the FERC may conduct a hearing and order a crude oil pipeline to make reparations going back for up to two years prior to the date on which a complaint was filed if a rate is found to be unjust and unreasonable. We can provide no assurance that current rates will remain unchallenged. Any successful challenge could have a material, adverse effect on our future earnings and cash flows.

TIGT

Pony Express Abandonment – FERC Docket CP12-495

On August 6, 2012, TIGT filed an application to: (1) abandon for FERC purposes approximately 433 miles of mainline natural gas pipeline facilities, along with associated rights of way and other related equipment (collectively, the "Pony Express Assets"), and the natural gas service therefrom, by transferring those assets to Pony Express, which subsequently converted the Pony Express Assets 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 conversion, which we refer to as the Replacement Gas Facilities. This project is referred to 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 the FERC in approving the Pony Express Abandonment, Pony Express is 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 Pony Express re-deployed existing pipeline assets to meet the growing market need to transport crude oil 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 a FERC 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 Pony Express. On May 1, 2014, TIGT commenced commercial service through all of the Replacement Gas Facilities, with the exception of Units 3 and 4 at the Tescott Compressor Station. Service through Units 3 and 4 at the Tescott Compressor Station commenced on May 30, 2014.

Cost and Revenue Study – FERC Docket RP11-1494

On October 3, 2015, TIGT submitted a cost and revenue study in compliance with Article IV of the Stipulation and Agreement of Settlement filed on May 5, 2011 in FERC Docket No. RP11-1494 ("2011 Settlement") and approved by the FERC on September 22, 2011. The cost and revenue study demonstrates that TIGT is under-recovering its cost of service. Consistent with the 2011 Settlement, the study was based on the unadjusted actual costs, revenues and volumes for a 12-month base period ended June 30, 2015, in compliance with Section 154.303(a)(1) of the FERC's regulations. The cost and revenue study did not propose any change to TIGT's currently effective rates. The cost and revenue study was accepted by FERC on February 1, 2016 in compliance with the 2011 Settlement.

General Rate Case Filing – FERC Docket RP16-137

On October 30, 2015, TIGT filed a general rate case with the FERC pursuant to Section 4 of the Natural Gas Act ("NGA"). The rate case proposed a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by TIGT. In addition, TIGT proposed certain changes to the transportation rate design of its system to replace the current rate zone structure with a single "postage stamp" rate. TIGT also proposed new incremental charges, including (i) a charge for deliveries made to points without certain electronic flow measurement equipment, and (ii) a Cost Recovery Mechanism ("CRM") charge to completely or partially reimburse TIGT for certain expenses and costs it incurs to comply with anticipated new PHMSA and EPA regulations. TIGT also proposed to replace its fixed fuel and lost and unaccounted for ("FL&U") charge with a FL&U tracker that would compensate TIGT for its actual FL&U expenses and adjust each year to reflect the previous period's under/over collection and the forecasted FL&U expense for the upcoming period. TIGT also proposed to implement a power cost tracker to recover the actual power costs incurred by TIGT to power its compressors. Finally, TIGT proposed certain revisions to its FERC Gas Tariff addressing a number of other rate and non-rate matters. Under the NGA and the FERC's regulations, TIGT's shippers and other interested parties, including the FERC's Trial Staff, have a right to challenge any aspect of TIGT's rate case filing. Accordingly, numerous TIGT customers have protested aspects of TIGT's NGA Section 4 rate filing.

On November 30, 2015, the FERC issued an order accepting and suspending the proposed rates and a majority of the proposed tariff records to be effective upon motion May 1, 2016, subject to refund, certain modifications to TIGT's proposed CRM charge, and the outcome of an evidentiary hearing before a FERC Administrative Law Judge (the "Suspension Order"). In the Suspension Order, the FERC also accepted two tariff records related to force majeure events and reservation charge crediting to be effective December 1, 2015, subject to certain modifications. On December 21, 2015, TIGT made a compliance filing with the FERC to modify TIGT's proposed CRM charge and update the tariff records related to force majeure events and reservation charge crediting as directed by the FERC in the Suspension Order. No comments or protests were filed in response to the compliance filing and FERC accepted the compliance filing on February 1, 2016. One request for rehearing of the Suspension Order is currently pending before the FERC with respect to the Suspension Order's acceptance, subject to a five-month suspension period, refund, the outcome of the hearing and the modifications made in TIGT's December 21, 2015 compliance filing, of TIGT's proposed CRM charge. The FERC Administrative Law Judge assigned to the proceeding has issued an order establishing the procedural schedule and TIGT, the FERC's Trial Staff, and other participants that successfully intervened are actively participating in the litigated proceeding to address those rate and tariff matters set for hearing by the FERC in its Suspension Order. On January 27, 2016, the FERC issued a tolling order to afford the FERC additional time for consideration of matters raised on rehearing regarding the Suspension Order. Additional FERC action is pending.

Trailblazer

2013 Rate Case Filing - Docket No. RP13-1031

On January 22, 2014, Trailblazer, the FERC's Trial Staff, and the active parties in the pipeline's general rate case finalized a settlement in principle resolving the pending rate issues, including: (i) establishing transportation rates, as well as fuel and lost and unaccounted for charges; (ii) providing a limited profit sharing arrangement for certain revenues earned from interruptible and short-term firm transport; and (iii) setting the minimum and maximum time that can elapse before Trailblazer's next rate case at the FERC. Trailblazer filed a motion with the FERC's Chief Administrative Law Judge to accept the settlement rates on an interim basis ("Interim Rates") while the participants finalized a definitive settlement. The Chief Administrative Law Judge accepted the Interim Rates effective February 1, 2014. On February 24, 2014, Trailblazer filed an uncontested offer of settlement ("Stipulation and Agreement") among active party shippers. The Stipulation and Agreement established the Interim Rates as final settlement rates effective February 1, 2014, subject to the issuance of refunds to certain shippers for January 2014 transportation services and revised fuel and lost and unaccounted for rates, effective July 1, 2014. On March 11, 2014, the Presiding Administrative Law Judge certified the Stipulation and Agreement. On May 29, 2014, the FERC approved the Stipulation and Agreement. On June 30, 2014, Trailblazer filed tariff sheets to implement the Stipulation and Agreement effective July 1, 2014. Estimated refunds were reserved from revenues recorded in January 2014. On July 1, 2014, Trailblazer submitted refunds to its customers for amounts collected in excess of amounts that would have been collected under the Settlement Rates, with interest, and on July 18, 2014, filed a report of refunds with the FERC. The FERC issued orders accepting the tariff sheets with the requested effective date of July 1, 2014 and accepting the refund report filing on July 25, 2014 and August 7, 2014, respectively. Per the terms of the Stipulation and Agreement, Trailblazer is required to file a new rate case by January 1, 2019, and no settling party was permitted to file a change to the settlement rates before January 1, 2016.

2015 Annual Fuel Tracker Filing - Docket No. RP15-841-000

On April 1, 2015, Trailblazer made its annual fuel tracker filing with a proposed effective date of May 1, 2015 in Docket No. RP15-841-000. This filing incorporates the revised fuel tracker and power cost tracker mechanisms agreed to in the Stipulation and Agreement, which resolves all outstanding issues related to Trailblazer fuel recoveries. The FERC approved this filing on April 23, 2015.

Pony Express

On September 19, 2014 Pony Express filed with the FERC to adopt a tariff for initial local non-contract rates as well as initial Rules and Regulations in accordance with the Interstate Commerce Act to be effective starting on October 1, 2014. Local Contract Tariff rates were filed with the FERC on October 29, 2014 to be effective starting November 1, 2014. Joint Contract Tariff rates for oil received into the Pony Express pipeline system from the Belle Fourche Pipeline were filed on October 16, 2014 to be effective starting November 1, 2014. Joint Contract Tariff rates for oil received into the Pony Express System from Hiland Pipeline Company were filed on February 27, 2015 and effective April 1, 2015.

On May 18, 2015, Pony Express filed with the FERC to implement tariff contract rates for Pony Express' newly constructed lateral in Northeast Colorado effective June 1, 2015.

On May 29, 2015, tariff filings were made with the FERC in Docket No. IS15-492-000 to increase the Pony Express local contract rates for service from the Guernsey origin, and for local non-contract rates from all origins, by amounts reflecting the FERC annual index adjustment of approximately 4.6% effective July 1, 2015. A tariff filing was also made in Docket No. IS15-493-000 on that date to increase joint tariff contract rates for service on Pony Express by approximately 4.6% effective July 1, 2015.

On October 29, 2015, Pony Express made a tariff filing with the FERC in Docket No. IS16-42-000 to increase the contract rates under its Local Pipeline Tariff for transportation from receipt points on its lateral in Northeast Colorado to various delivery points in Oklahoma, by an amount reflecting the most recent FERC annual index adjustment of approximately 4.6% effective December 1, 2015.

17. Legal and Environmental Matters

Legal

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

We have evaluated claims in accordance with the accounting guidance for contingencies that we deem both probable and reasonably estimable and, accordingly, have recorded no reserve for legal claims as of December 31, 2015. We had reserves for legal claims of approximately $0.6 million as of December 31, 2014.

Prairie Horizon

On July 3, 2014, Prairie Horizon Agri-Energy LLC ("Prairie Horizon") filed an action in the District Court of Phillips County, Kansas against TIGT seeking damages from an alleged intrusion of foreign material and oil from TIGT into Prairie Horizon's ethanol plant. The matter was removed to the U.S. District Court for the District of Kansas. Prairie Horizon asserted that this intrusion caused substantial damage to Prairie Horizon's ethanol production facilities and resulted in corresponding business income losses. Prairie Horizon also claimed that the intrusion was a violation of TIGT's FERC gas tariff. On September 25, 2015, TIGT and Prairie Horizon reached a settlement agreeing to dismiss all claims with prejudice and releasing TIGT from any further liability.

Environmental, Health and Safety

We are subject to a variety of federal, state and local laws that regulate permitted activities relating to air and water quality, waste disposal, and other environmental matters. We believe that compliance with these laws will not have a material adverse impact on our 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 us to incur significant costs. We had environmental reserves of $4.8 million and $5.3 million at December 31, 2015 and 2014, respectively.

TMID

Casper Plant, U.S. EPA Notice of Violation

In August 2011, the U.S. EPA and the Wyoming Department of Environmental Quality ("WDEQ") conducted an inspection of the Leak Detection and Repair ("LDAR") Program at the Casper Gas Plant in Wyoming. In September 2011, Tallgrass Midstream, LLC ("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. TMID received a letter from the U.S. EPA concerning settlement of this matter in April 2013 and received additional settlement communications from the U.S. EPA and Department of Justice beginning in July 2014. Settlement negotiations are continuing, including attempted resolution of more recently identified LDAR issues and the expected inclusion of TIGT as a party to any possible settlement as a result of TIGT owning a compressor that is located adjacent to the Casper Gas Plant site.

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 we have requested that the portion of the site attributable to us be delisted from the National Priorities List.

Casper Gas Plant

On November 25, 2014, WDEQ issued a Notice of Violation for violations of Part 60 Subpart OOOO related to the Depropanizer project (wv-14388, issued 7/9/13) in Docket No. 5506-14. TMID had discussed the issues in a meeting with WDEQ in Cheyenne on November 17, 2014, and submitted a disclosure on November 20, 2014 detailing the regulatory issues and potential violations. The project triggered a modification of Subpart OOOO for the entire plant. The project equipment as well as plant equipment subjected to Subpart OOOO was not monitored timely, and initial notification was not made timely. Settlement negotiations with WDEQ are currently ongoing.

TIGT

System Failure

On June 13, 2013, a failure occurred on a segment of the TIGT pipeline system in Goshen County, Wyoming, resulting in the release of natural gas and the issuance of a Corrective Action Order ("CAO") by PHMSA. The line was promptly brought back into service and the failure did not cause any known injuries, fatalities, fires or evacuations. Pursuant to a letter dated August 14, 2015, PHMSA informed TIGT that it had complied with the terms of the CAO and declared the case closed. As of December 31, 2015, remediation activities were complete. The total cost of remediation was not material.

Trailblazer

Pipeline Integrity Management Program

Trailblazer recently conducted smart tool surveys and preliminary analysis on segments of its natural gas pipeline to evaluate the growth rate of corrosion downstream of compressor stations. Trailblazer currently believes that approximately 25 - 35 miles of pipe will likely need to be repaired or replaced in order for the pipeline to operate at its maximum allowable operating pressure of 1,000 pounds per square inch. Such repair or replacement will likely occur over a period of years, depending upon final assessment of corrosion growth rates and the remediation and repair plan implemented by Trailblazer. Trailblazer is currently operating at less than its current maximum allowable operating pressure, public notice of which was first provided in June 2014. The current pressure reduction is not expected to prevent Trailblazer from fulfilling its firm service obligations at existing subscription levels and to date it has not had a material adverse financial impact on TEP.

During 2015, Trailblazer completed 32 excavation digs at an aggregate cost of approximately $1.3 million based on preliminary analysis of the smart tool surveys performed in 2014. Segments of the Trailblazer Pipeline that require full replacement are currently expected to cost in the range of approximately $2.2 million to $2.7 million per mile. Repair costs on sections of the pipeline that do not require full replacement are expected to be less on a per mile basis. Trailblazer is continuing to develop a remediation and repair plan, which involves, among other things, finalizing cost recovery options, establishing project scope and timing and setting an overall project budget. In 2016, Trailblazer intends to replace approximately 8 miles of pipe at an estimated cost of $21.5 million. Trailblazer is currently exploring all possible cost recovery options. It may not ultimately be able to recover any or all of such out of pocket costs unless and until Trailblazer recovers them through a general rate increase or other FERC-approved recovery mechanism, or through negotiated rate agreements with its customers.

In connection with TEP's acquisition of the Trailblazer Pipeline, TD agreed to contractually indemnify TEP for any out of pocket costs incurred between April 1, 2014 and April 1, 2017 related to repairing or remediating the Trailblazer Pipeline, to the extent that such actions are necessitated by external corrosion caused by the pipeline's disbonded Hi-Melt CTE coating. The contractual indemnity provided to TEP by TD is currently capped at $20 million and is subject to an annual $1.5 million deductible.

Pony Express

System Failures

On August 31, 2014, a leak occurred at the Sterling Pump Station on the Pony Express System in Logan County, Colorado, which resulted in a release of approximately 200 bbls of crude oil. The spill was entirely contained on our property and the costs to remediate were not material. In April 2015, PHSMA granted our request to consider the Sterling Pump Station incident closed with no further action.

On March 12, 2015, an event occurred at the Yoder Pump Station in Goshen County, Wyoming, related to repair and replacement activities resulting in a spill of approximately 300 bbls of crude oil. As of December 31, 2015, remediation activities were complete. The total cost of remediation was not material and the matters have been closed by the applicable agencies.

18. Reporting Segments

Our operations are located in the United States. We are organized into three reporting segments: (1) Crude Oil Transportation & Logistics, (2) Natural Gas Transportation & Logistics, and (3) Processing & Logistics.

Crude Oil Transportation & Logistics

The Crude Oil Transportation & Logistics segment is engaged in the ownership and operation of the Pony Express System, which is a FERC-regulated crude oil pipeline serving the Bakken Shale and other nearby oil producing basins. The mainline portion of the Pony Express System was placed in service in October 2014. The Pony Express System also includes a lateral pipeline in Northeast Colorado, which interconnects with the Pony Express System just east of Sterling, Colorado and was placed in service in the second quarter of 2015. As discussed in Note 2 – *Summary of Significant Accounting Policies*, results for prior periods have been recast to reflect the operations of Pony Express.

Natural Gas Transportation & Logistics

The Natural Gas Transportation & Logistics segment is engaged in the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities that provide services to on-system customers (such as third-party LDCs), industrial users and other shippers. As discussed in Note 2 – *Summary of Significant Accounting Policies*, results for prior periods have been recast to reflect the operations of Trailblazer.

Processing & Logistics

The Processing & Logistics 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 business services provided primarily to the oil and gas exploration and production industry.

Corporate and Other

Corporate and Other includes corporate overhead costs that 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.

We consider Adjusted EBITDA our primary segment performance measure as we believe it is the most meaningful measure to assess our financial condition and results of operations as a public entity. We define Adjusted EBITDA, a non-GAAP measure, as net income excluding the impact of 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 or business disposals or acquisitions, gains or losses on the repurchase, redemption or early retirement of debt, and earnings from unconsolidated investments, but including the impact of distributions from unconsolidated investments.

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

	Year Ended December 31,								
	2015			2014			2013		
Revenue:	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue
	(in thousands)								
Crude Oil Transportation & Logistics	$304,227	$ —	$304,227	$ 28,343	$ —	$ 28,343	$ —	$ —	$ —
Natural Gas Transportation & Logistics	131,657	(5,384)	126,273	140,080	(5,257)	134,823	127,877	(1,920)	125,957
Processing & Logistics	105,697	—	105,697	208,390	—	208,390	164,569	—	164,569
Corporate and other	—	—	—	—	—	—	—	—	—
Total revenue	$541,581	$ (5,384)	$536,197	$ 376,813	$ (5,257)	$371,556	$292,446	$ (1,920)	$290,526

	Year Ended December 31,								
	2015			2014			2013		
Adjusted EBITDA:	Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA
					(in thousands)				
Crude Oil Transportation & Logistics	$165,204	$ 5,384	$170,588	$ 15,711	$ —	$ 15,711	$ (43)	$ —	$ (43)
Natural Gas Transportation & Logistics	67,368	(5,384)	61,984	67,593	(4,015)	63,578	56,821	(1,920)	54,901
Processing & Logistics	22,746	—	22,746	33,089	—	33,089	23,192	1,920	25,112
Corporate and other	(2,979)	—	(2,979)	(2,500)	—	(2,500)	(1,580)	—	(1,580)
Reconciliation to Net Income:									
Add:									
Equity in earnings of unconsolidated investment			—			717			—
Non-cash loss allocated to noncontrolling interest			9,377			10,151			—
Gain on remeasurement of unconsolidated investment			—			9,388			—
Less:									
Interest expense, net of noncontrolling interest			(15,517)			(7,648)			(11,035)
Depreciation and amortization expense, net of noncontrolling interest			(75,529)			(45,389)			(37,898)
Non-cash (gain) loss related to derivative instruments			—			184			(386)
Non-cash compensation expense			(5,103)			(5,136)			(1,798)
Non-cash loss from asset sales			(4,795)			—			—
Distributions from unconsolidated investment			—			(1,464)			—
Loss on extinguishment of debt			(226)			—			(17,526)
Net income attributable to partners			$160,546			$ 70,681			$ 9,747

Capital Expenditures:	Year Ended December 31, 2015	2014	2013
	(in thousands)		
Crude Oil Transportation & Logistics	$ 38,802	$ 631,883	$ 286,824
Natural Gas Transportation & Logistics	10,478	20,580	28,184
Processing & Logistics	16,107	13,187	31,012
Total capital expenditures	$ 65,387	$ 665,650	$ 346,020

Assets:	December 31, 2015	December 31, 2014
	(in thousands)	
Crude Oil Transportation & Logistics	$ 1,439,418	$ 1,394,793
Natural Gas Transportation & Logistics	706,576	716,106
Processing & Logistics	409,795	340,620
Corporate and other	6,285	5,678
Total assets	$ 2,562,074	$ 2,457,197

19. Selected Quarterly Financial Data (Unaudited)

The following tables summarize our unaudited quarterly financial data for 2015 and 2014:

	Quarter Ended 2015 First	Second	Third	Fourth
	(in thousands, except per unit amounts)			
Total revenues	$ 114,675	$ 132,970	$ 138,168	$ 150,384
Operating income	$ 25,718	$ 56,355	$ 52,919	$ 62,923
Net income	$ 22,990	$ 53,231	$ 49,550	$ 59,043
Net income attributable to partners	$ 32,319	$ 44,899	$ 42,679	$ 40,649
Net income allocable to limited partners	$ 24,881	$ 33,869	$ 30,533	$ 24,785
Basic net income per limited partner unit	$ 0.47	$ 0.56	$ 0.50	$ 0.41
Diluted net income per limited partner unit	$ 0.46	$ 0.55	$ 0.50	$ 0.40

	Quarter Ended 2014 First	Second	Third	Fourth
	(in thousands, except per unit amounts)			
Total revenues	$ 94,779	$ 77,320	$ 89,953	$ 109,504
Operating income	$ 16,529	$ 6,475	$ 11,580	$ 18,829
Net income	$ 16,617	$ 14,728	$ 11,253	$ 16,731
Net income attributable to partners	$ 17,124	$ 15,286	$ 11,444	$ 26,827
Net income allocable to limited partners	$ 12,518	$ 15,771	$ 11,143	$ 22,342
Basic net income per limited partner unit	$ 0.31	$ 0.39	$ 0.24	$ 0.46
Diluted net income per limited partner unit	$ 0.30	$ 0.38	$ 0.23	$ 0.45

20. Subsequent Events

Acquisition of an Additional 31.3% of Pony Express

Effective January 1, 2016, TEP acquired an additional 31.3% membership interest in Pony Express in exchange for cash consideration of $475 million and 6,518,000 TEP common units (valued at approximately $268.6 million based on the December 31, 2015 closing price of TEP's common units) issued to TD for total consideration of approximately $743.6 million. The transaction increases TEP's aggregate membership interest in Pony Express to 98.0%. As part of the transaction, TD granted TEP an 18 month call option to repurchase the newly issued 6,518,000 common units at a price of $42.50.

Revolving Credit Facility

In connection with the acquisition of an additional 31.3% membership interest in Pony Express as discussed above, TEP exercised its option to increase the commitment under its existing Credit Agreement from $1.1 billion to $1.5 billion effective January 4, 2016. As of January 31, 2016, TEP had approximately $1.2 billion of outstanding borrowings under its revolving credit facility.

Tallgrass Development Purchase Program

On February 17, 2016, TEP and Tallgrass Energy GP, LP ("TEGP") announced that the Board of Directors of Tallgrass Energy Holdings, LLC, the sole member of TEGP's general partner and the general partner of TD, has authorized an equity purchase program under which TD may initially purchase up to an aggregate of $100 million of the outstanding Class A shares of TEGP or the outstanding common units of TEP. TD may purchase Class A shares or Common Units from time to time on the open market or in negotiated purchases. The timing and amounts of any such purchases will be subject to market conditions and other factors, and will be in accordance with applicable securities laws and other legal requirements. The purchase plan does not obligate TD to acquire any specific number of Class A shares or Common Units and may be discontinued at any time.

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

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based upon their evaluation of those controls and procedures performed as of December 31, 2015, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective at the reasonable assurance level.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed under the supervision of our principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2015, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in the 2013 "Internal Control - Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. On December 16, 2015, we completed our acquisition of BNN Western, LLC. Management has elected to exclude BNN Western, LLC from management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2015 because it was acquired by the Partnership in a business combination on December 16, 2015. Total assets and total revenues of BNN Western, LLC represent 3% and less than 1%, respectively, of our total assets and total revenues as reported in our consolidated financial statements as of and for the year ended December 31, 2015. Based on this assessment and those criteria, management determined that we maintained effective internal control over financial reporting as of December 31, 2015.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our independent registered public accounting firm, PricewaterhouseCoopers LLP, audited the effectiveness of our internal control over financial reporting as of December 31, 2015, as stated in their report included in Item 8.—Financial Statements and Supplementary Data of this Annual Report.

Changes in Internal Control over Financial Reporting

There have not been any 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, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

We are a limited partnership and 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 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. 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.

Tallgrass Equity is the sole member of our general partner and has the right to appoint all of the officers and directors of our general partner. TEGP owns a 30.35% membership interest in, and is the managing member of, Tallgrass Equity. TEGP Management is TEGP's general partner. Tallgrass Energy Holdings is the sole member of TEGP Management and has the right to appoint the entire board of directors of TEGP Management, including its independent directors.

Tallgrass Energy Holdings effectively controls our business and affairs through the exercise of its rights as the party that controls Tallgrass Equity, including its right to appoint members to the board of directors of our general partner. EMG, Kelso and Tallgrass KC, LLC (an entity owned by certain members of our management, "Tallgrass KC") own, in the aggregate, approximately 100% of the outstanding membership interests in Tallgrass Energy Holdings.

As of December 31, 2015, the board of directors of our general partner had nine directors, four of whom the board has determined meet the independence standards established by the NYSE and the Exchange Act. The four independent directors are Jeffrey A. Ball (for purposes of Audit Committee participation only), Terrance D. Towner, Roy N. Cook, and Jeffrey R. Armstrong. The NYSE does not require a publicly-traded limited partnership like 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, 2015, the audit committee of the board of directors of our general partner had three members, each of whom meet the independence standards established by the NYSE and the Exchange Act.

In evaluating director candidates, Tallgrass Energy Holdings 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 the executive officers of our general partner are also officers of Tallgrass Equity, TEGP Management, and Tallgrass Energy Holdings. Our officers 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 and the TEP Omnibus Agreement each provides that our general partner will determine in good faith the expenses that are allocable to us. In addition, the TEP Omnibus Agreement requires us to reimburse Tallgrass Energy Holdings and its affiliates for expenses they incur in providing general and administrative services to us. Neither our partnership agreement nor the TEP Omnibus Agreement limits the amount of expenses for which our general partner or Tallgrass Energy Holdings and its affiliates may be reimbursed.

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 February 17, 2016.

Name	Age	Position with our General Partner
David G. Dehaemers, Jr.	55	President, Chief Executive Officer and Director
William R. Moler	50	Executive Vice President, Chief Operating Officer and Director
Gary J. Brauchle	42	Executive Vice President and Chief Financial Officer
George E. Rider	62	Executive Vice President, General Counsel and Secretary
Richard L. Bullock	60	Vice President, Human Resources, Tax and Risk Management
Gary D. Watkins	43	Vice President and Chief Accounting Officer
Frank J. Loverro	46	Director
Stanley de J. Osborne	45	Director
Jeffrey A. Ball	41	Director
John T. Raymond	45	Director
Terrance D. Towner	57	Director
Roy N. Cook	58	Director
Jeffrey R. Armstrong	46	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 the President and Chief Executive Officer of our general partner since February 2013 and of TEGP Management since February 2015. Mr. Dehaemers has served as the President and Chief Executive Officer of Tallgrass Equity since February 2013 and as a director and the President and Chief Executive Officer of Tallgrass Energy Holdings 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, or 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., or 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 boards of directors of our general partner and of TEGP Management.

William R. Moler has been a director, Executive Vice President and Chief Operating Officer of our general partner since February 2013 and of TEGP Management since February 2015. Mr. Moler has also served as Executive Vice President and Chief Operating Officer of Tallgrass Equity since February 2013 and as a director, Executive Vice President and Chief Operating Officer of Tallgrass Energy Holdings 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. and its predecessors 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 boards of directors of our general partner and of TEGP Management.

Gary J. Brauchle has been Executive Vice President and Chief Financial Officer of our general partner since February 2013 and of TEGP Management since February 2015. Mr. Brauchle has also served as Executive Vice President and Chief Financial Officer of Tallgrass Equity since February 2013 and of Tallgrass Energy Holdings 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 of TEGP Management since February 2015. Mr. Rider has also served as Executive Vice President, General Counsel and Secretary of Tallgrass Equity since February 2013 and of Tallgrass Energy Holdings since August 2012. From 2008 to August 2012, Mr. Rider was Vice President and General Counsel for Tallgrass MLP Fund I, L.P., a private MLP Investment Fund. From 1986 to 2008, Mr. Rider was an attorney with the law firm that is now known as Stinson Leonard Street 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 of TEGP Management since February 2015. Mr. Bullock has also served as Vice President of Human Resources, Tax and Risk Management of Tallgrass Equity since February 2013 and of Tallgrass Energy Holdings 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.

Gary D. Watkins has been Vice President and Chief Accounting Officer and the principal accounting officer of our general partner since April 2014 and of TEGP Management since February 2015. Mr. Watkins has also served as Vice President and Chief Accounting Officer of Tallgrass Equity and of Tallgrass Energy Holdings since February 2015. Previously, Mr. Watkins served as Vice President, Controller and principal accounting officer of DCP Midstream Partners, LP and DCP Midstream, LLC from May 2011 until April 2014. Prior to that, Mr. Watkins had held the positions of Senior Director—Marketing Accounting and Director of Corporate Accounting with DCP Midstream, LLC. Prior to joining DCP Midstream, LLC in November 2004, Mr. Watkins held various positions of increasing responsibility at Advanced Energy Industries, Inc. Mr. Watkins also served in the Denver offices of Arthur Andersen LLP and KPMG LLP from 1996 through 2002.

Frank J. Loverro has served as a director of our general partner since February 2013 and of TEGP Management since February 2015. Mr. Loverro has also served as a director of Tallgrass Energy Holdings since August 2012. Mr. Loverro joined Kelso in 1993, has been Managing Director since 2004 and a Member of Kelso's Management Committee since 2013, and in 2016 became Co-CEO. 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 Ajax Resources, LLC, 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 boards of directors of our general partner and of TEGP Management.

Stanley de J. Osborne has served as a director of our general partner since February 2013 and of TEGP Management since February 2015. Mr. Osborne has also served as a director of Tallgrass Energy Holdings 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 Ajax Resources, LLC, 4Refuel Canada LP, Hunt Marcellus, LLC, Logan's Roadhouse, Inc., Traxys S.a.r.l, Power Team Services, LLC and LBM Acquisition, LLC. Mr. Osborne was also previously a director of CVR Energy, Inc. and Global Geophysical Services, 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 boards of directors of our general partner and of TEGP Management.

Jeffrey A. Ball has served as a director of our general partner since May 2013 and of TEGP Management since February 2015. Mr. Ball has also served as the Chairman of the Audit Committee of our general partner since May 2013 and as the Chairman of the Audit Committee of TEGP Management since April 2015. Further, Mr. Ball has served as a director of Tallgrass Energy Holdings since August 2012. Mr. Ball is a Managing Director at EMG, a diversified natural resource private equity fund manager, and is responsible for transaction origination, structuring and execution, portfolio company management and investment realization. Prior to joining EMG in October 2007, Mr. Ball was a Director in the investment banking group at Credit Suisse Securities (USA), LLC, covering the energy industry with a particular focus on MLPs and the midstream sector. Mr. Ball has completed over $50 billion of mergers and acquisitions and capital markets financing transactions during his career in the energy and minerals 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, Ferus Natural Gas Fuels (CNG), LLC, American Energy Appalachia Holdings, LLC, American Energy Permian Basin Holdings, LLC and is a board observer of MarkWest Utica EMG, LLC. Mr. Ball received a B.S. in Economics with honors from the Wharton School at the University of Pennsylvania. 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 boards of directors of our general partner and of TEGP Management.

John T. Raymond has served as a director of our general partner since February 2013 and of TEGP Management since February 2015. Mr. Raymond has also served as a director of Tallgrass Energy Holdings since August 2012. Mr. Raymond is an owner and founder of The Energy & Minerals Group. EMG is a diversified natural resource private equity fund manager with approximately $16.4 billion of regulatory assets under management (RAUM) as of October 29, 2015. EMG has allocated approximately $8.8 billion in commitments across the energy sector since inception. Mr. Raymond has been Managing Partner and CEO since EMG's inception in 2006. Prior 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. Mr. Raymond received a BSM degree from the A.B. Freeman School of Business at Tulane University with dual concentrations in finance and accounting. 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 boards of directors of our general partner and of TEGP Management.

Terrance D. Towner has served as a director of our general partner and as a member of the audit committee of our general partner since August 2013. Mr. Towner currently provides advisory services to various private equity clients and private companies. Between 2000 and December 2014, Mr. Towner was employed by Watco Companies, a Kansas based transportation company, in various capacities, including Vice Chairman, President, COO and CFO. As President and COO, Mr. Towner was responsible for all operations, safety, quality, human resources, information services and the 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 computer based education products, and approximately two years as a financial and strategic consultant with Grant Thornton. Following his departure from Grant Thornton, Mr. Towner acquired Joplin.com, an internet service provider located in Joplin, Missouri and subsequently sold the company to Empire District Electric Company, a public utility. Mr. Towner earned his bachelor's degree in Economics from Pittsburg State University in 1981 and his MBA from Pittsburg State University in 1993. We believe that Mr. Towner's business acumen, and a unique perspective on the midstream services industry, helps provide valuable strategic and practical guidance, insight, and perspective to the board of directors of our general partner.

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. We believe that Mr. Cook's MLP experience, and his intricate knowledge of the terminals business provides valuable strategic and practical insight, and perspective to the board of directors of our general partner.

Jeffrey R. Armstrong has served as a director of our general partner and as a member of the audit committee of our general partner since April 2014. Mr. Armstrong also serves as a director and a member of the audit committee of the general partner of Arc Logistics Partners LP, a publicly traded limited partnership that is principally engaged in the terminalling, storage, throughput and transloading of crude oil and petroleum products. In August 2014, Mr. Armstrong became the Chief Executive Officer of Zenith Energy, LP, a privately held midstream energy company focused on international matters. In October 2014, Mr. Armstrong became the chairman of MID-SHIP Group, a privately held logistics and transportation company. Mr. Armstrong is the Manager and controlling shareholder of MID-SHIP Capital LLC, which owns 100% of MID-SHIP Securities LLC, a member of the Financial Industry Regulatory Authority, or FINRA. From March 2001 until December 2013, Mr. Armstrong was employed by Kinder Morgan and held various positions within the company including Vice President of Corporate Strategy and President of the Terminals division. Prior to 2001, Mr. Armstrong was employed by GATX Corporation where he held various commercial and operational roles including General Manager of the company’s east coast operations. He received his bachelor’s degree from the U.S. Merchant Marine Academy and an MBA from the University of Notre Dame. We believe that Mr. Armstrong's extensive experience as it relates both to general corporate strategy and specifically to the terminals business, provides valuable insight and perspective to the board of directors of our general partner.

Audit Committee

The Board of Directors of our General Partner has a standing audit committee which is currently comprised of three directors, Jeffrey A. Ball, Terrance D. Towner, and Jeffrey R. Armstrong. Each audit committee member has past experience in accounting or related financial management experience. The board has determined that all 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.

A copy of the Audit Committee Charter is available to any person, free of charge, at our website at www.tallgrassenergy.com.

Conflicts Committee

The Board of Directors of our General Partner periodically establishes a conflicts committee comprised of independent directors to resolve potential conflicts of interest between our general partner and its affiliates, on one hand, and us and our unitholders, on the other. The conflicts committee currently consists of three independent directors, Roy Cook, Terry Towner and Jeff Armstrong, with Roy Cook currently acting as the chairman. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, to have been approved by all of our unitholders, and not to involve a breach of any duties that may be owed to our unitholders.

Corporate Governance Guidelines

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.

The Chairman of the Audit Committee of our general partner, currently Jeffrey A. Ball, presides over any executive session of the board of directors of our general partner in which the members of our management are not present. Interested parties may communicate directly with the independent members of the board of directors of our general partner by submitting in an envelope marked "Confidential" addressed to the "Independent Members of the Board" in care of the Secretary of the General Partner at: Tallgrass Energy Partners, LP, 4200 W. 115th Street, Suite 350, Leawood, Kansas 66211.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner's board of directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file with the SEC, and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater than 10% unitholders are required by the SEC's regulations to furnish to us and any exchange or other system on which such securities are traded or quoted with copies of all Section 16(a) forms they file with the SEC.

Based solely upon a review of Forms 3, 4 and 5, and amendments thereto, we know of no director, officer, or beneficial owner of more than 10% of any class of our equity securities registered pursuant to Section 12 of the Exchange Act that failed to file timely any reports required to be furnished during 2014 pursuant to Section 16(a) of the Exchange Act, except that on January 5, 2016, (i) TEGP and TEGP Management filed a Form 3 that was due on May 22, 2015, (ii) Tallgrass Operations and Tallgrass Development filed a Form 4 that was due on May 14, 2015, (iii) Tallgrass Energy Holdings filed a Form 4 due on May 14, 2015 and (iv) Tallgrass Equity filed a Form 4 due on May 13, 2015.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Executive Summary and Background

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 our Named Executive Officers (as defined in *"-Summary Compensation Table"* below), are employed by an affiliate of our general partner, Tallgrass Management, LLC ("Tallgrass Management").

Compensation of our Named Executive Officers is set and approved by the board of directors of our general partner and by the board of managers of Tallgrass Energy Holdings, which indirectly controls our general partner. Tallgrass Energy Holdings owns 100% of Tallgrass Management and 100% of the general partner of TEGP. As of February 17, 2016, TEGP owns a 30.35% membership interest in and is managing member of Tallgrass Equity, which owns a 29.41% limited partner interest in us and, through its ownership of all of the membership interests in our general partner, our general partner interest and our incentive distribution rights. Tallgrass Energy Holdings also serves as the general partner of Tallgrass Development. We reimburse Tallgrass Development for all salaries, benefits and other compensation expenses for employees of Tallgrass Management (including the Named Executive Officers) to the extent such employees provide services to us pursuant to an allocation agreed upon between us and Tallgrass Development under the terms of the TEP Omnibus Agreement. Other than the employment agreement with our Chief Executive Officer, David G. Dehaemers, Jr., none of our Named Executive Officers has entered into any employment agreements with Tallgrass Management, our general partner or any other affiliate of TEP.

Philosophy and Objectives

Since TEP's initial public offering in May 2013, we have employed a compensation philosophy that emphasizes pay for performance and places the majority of each Named Executive Officer's compensation at risk. We believe our pay-for-performance approach aligns the interests of our Named Executive Officers with that of our unitholders, and at the same time enables us to maintain a lower level of recurring compensation costs in the event our operating or financial performance is below expectations. We design our executive compensation to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our unitholders, and to reward success in reaching such goals.

We use three primary elements of compensation to fulfill that design-salary, cash bonus and long-term equity incentive awards. Cash bonuses and long-term equity incentives (as opposed to salary) generally represent the performance driven elements. They are also flexible in application and can be tailored to meet our objectives. The determination of specific individuals' cash bonuses is based on their relative contribution to achieving or exceeding relative near-term company goals and the determination of specific individuals' long-term incentive equity awards is based on their expected contribution in respect of longer term performance objectives. The primary long-term measure of our performance is our ability to increase quarterly distributions to our unitholders while maintaining safe operations and long term stable cash flow and financial health.

We do not maintain a defined benefit or pension plan for our Named Executive Officers as we believe such plans primarily reward longevity and not performance. We provide a basic benefits package generally to all employees, which includes a 401 (k) plan and health, disability and life insurance.

Elements of Compensation

Salary. We do not "benchmark" our salary or bonus amounts. We believe our salaries are generally competitive with the universe of similarly situated master limited partnerships, but are moderate relative to energy industry competitors for people with similar roles and responsibilities.

Cash Bonuses. Our cash bonuses are annual discretionary bonuses in which all of our current Named Executive Officers potentially participate.

Long-Term Incentive Awards. Effective May 13, 2013, our general partner adopted a Long-Term Incentive Plan ("TEP LTIP") pursuant to which awards based on common units of TEP in the form of restricted units, equity participation units, unit options, unit appreciation rights, distribution equivalent rights and unit awards may be granted to employees, consultants, and directors of TEP GP and its affiliates who perform services for or on behalf of TEP or its affiliates, including Tallgrass Development. Historically, we have used equity participation unit grants issued under the TEP LTIP to encourage and reward timely achievement of certain events or TEP distribution levels and align the long-term interests of our Named Executive Officers with those of our unitholders. An equity participation unit is the right to receive, upon the satisfaction of vesting criteria specified in the grant, a common unit.

The vesting conditions applicable to our outstanding equity participation unit awards can generally be divided into two categories. The first category of awards was granted between June 2013 and September 2014 with vesting of such awards contingent upon the Pony Express System going into commercial service, which occurred in October 2014. Thus, the awards in this category will vest as long as the employee satisfies the continuing service requirement set forth in the applicable award agreement. Generally, one-third of the awards in this category vested on May 13, 2015 and the remaining two-thirds will vest on May 13, 2017. All of our Named Executive Officers other than Mr. Dehaemers were granted equity participation unit awards in this category.

The second category of equity participation unit awards were granted between August 2015 and September 2015 with vesting occurring in two parts. One-half vests on the later to occur of the first date on which we have paid a regular quarterly distribution of at least $0.6875 on each outstanding common unit (the "TEP Distribution Achievement Date") or May 13, 2018, and the other half vesting on the later to occur of the Distribution Achievement Date or May 13, 2019. If we have not distributed at least $0.6875 on each outstanding common unit for any full quarter ending on or before May 13, 2020, the unvested EPUs will expire and no vesting will occur. In all cases, award recipients must meet continuing service requirements specified in the applicable award agreement. Mr. Watkins is the only Named Executive Officer that was granted equity participation units in this second category.

Effective May 1, 2015, TEGP Management, the general partner of TEGP, adopted a Long-Term Incentive Plan ("TEGP LTIP") pursuant to which awards based on Class A shares of TEGP in the form of restricted shares, equity participation shares, options, share appreciation rights, distribution equivalent rights and share awards may be granted to employees, consultants, and directors of Tallgrass Management and its affiliates who perform services for or on behalf of TEGP or its affiliates, including TEP and Tallgrass Development (such awards, collectively with the awards under the TEP LTIP, the "LTIP Awards"). Equity participation shares may be issued under the TEGP LTIP to, in part, align the long-term interests of certain Named Executive Officers of TEP with those of our unitholders. We believe this alignment results from TEGP’s ownership of a 30.35% controlling membership interest in Tallgrass Equity, which owns a 29.41% limited partnership interest in us, all of our general partner interest and all of our incentive distribution rights. An equity participation share is the right to receive, upon the satisfaction of vesting criteria specified in the grant, a TEGP Class A share.

In 2015, grants of equity participation shares were made under TEGP LTIP, including a grant made to Mr. Watkins, who is thus far the only Named Executive Officer to receive a grant under the TEGP LTIP. The terms of Mr. Watkins' award stipulates that his equity participation shares will generally vest upon the later of the first date on which TEGP pays a regular quarterly distribution of at least $0.35 on each outstanding Class A share (the "TEGP Distribution Date") or May 12, 2019. If TEGP has not distributed at least $0.35 on each outstanding Class A Share for any full quarter ending on or before May 12, 2020, the unvested equity participation shares will expire and no vesting will occur. Mr. Watkins must also remain in continuous employment through the vesting date.

Relation of Compensation Elements to Compensation Objectives

Our compensation program is designed to motivate, reward and retain our Named Executive Officers. Cash bonuses serve as a near-term motivation and reward for achieving positive short-term results, such as meeting specified distribution growth and other financial guidance targets. Longer-term retention is facilitated by the requirement for continued employment or service for specified time periods in order for LTIP Awards to fully vest. The level of cash bonuses and LTIP Awards reflect the moderate salary profile of our Named Executive Officers and the weighting towards performance based, at-risk compensation.

We strive to focus on performance-based compensation elements in an attempt to create a performance-driven environment in which our Named Executive Officers are (i) motivated to perform over both the short-term and the long-term, (ii) appropriately rewarded for their services and (iii) encouraged to remain with us even after meeting long-term performance goals. We believe our compensation philosophy as implemented by application of the three primary compensation elements (i) aligns the interests of our Named Executive Officers with our unitholders, (ii) positions us to achieve our business goals, and (iii) effectively encourages the exercise of sound judgment and risk-taking that is conducive to creating and sustaining long-term value. We believe the processes we employ to apply the elements of compensation (as discussed in more detail below) provide an adequate level of oversight with respect to the degree of risk being taken by management to achieve short-term and long-term performance goals. See *"Relation of Compensation Policies and Practices to Risk Management."*

We believe our compensation program has been instrumental in our achievement of stated objectives. The first category of awards was granted between June 2013 and September 2015 with vesting contingent, in part, upon the Pony Express System going into commercial service, which occurred on October 2014. As noted above, two-thirds of those awards still remain subject to the continuing service requirement set forth in the applicable award agreement, which has supported our goal of long-term retention of Named Executive Officers. Additionally, one of the primary measures of our performance is our ability to enhance the ability of our assets to generate distributable cash flow that we can use to increase quarterly distributions to our unitholders. In the period since our initial public offering through December 31, 2015, our annual distribution per common unit has grown at a compound annual rate of 37.7%. This distribution growth has, in part, supported our decision to pay cash bonuses to our Named Executive Officers over that period.

Application of Compensation Elements

Salary. We do not make systematic annual adjustments to the salaries of our Named Executive Officers. We do, however, make salary adjustments as necessary to ensure that our salaries remain competitive in the industry marketplace.

Annual Discretionary Cash Bonuses. Annual discretionary bonuses are determined based on our performance relative to our annual budget, our distribution growth targets, and other quantitative and qualitative goals established each year. Such annual objectives are discussed and reviewed with the board of directors in conjunction with the review and authorization of the annual budget.

At the end of each year, the CEO, with assistance from other members of executive management, performs a quantitative and qualitative assessment of our performance relative to our goals. Key quantitative measures include Adjusted EBITDA, distributable cash flow, distribution coverage, and growth in the annualized quarterly distribution level per common unit relative to annual growth targets. We also compare our market performance relative to our MLP peers and major indices. Our primary performance metric is our ability to generate increasing and sustainable cash distributions to our unitholders. Accordingly, although net income and net income per unit are monitored to highlight inconsistencies with our primary performance metrics, we do not consider net income and net income per unit to be key performance measures. The CEO's analysis of our performance examines our accomplishments, shortfalls and overall performance against opportunity, taking into account controllable and non-controllable factors encountered during the year.

Based on the conclusions reached by our CEO in the annual performance review discussed above, the CEO submits recommendations to the board of directors of our general partner and the board of managers of Tallgrass Energy Holdings for cash bonuses and salary adjustments for certain key employees, including our Named Executive Officers, taking into account the relative contribution of the individual employee. There are no set formulas for determining salary adjustments or annual discretionary bonuses for our Named Executive Officers. Factors considered by the CEO in determining the level of adjustment and bonus in general include (i) whether or not we achieved any goals established for the year and any notable shortfalls relative to expectations; (ii) the level of difficulty associated with achieving any such objectives based on the opportunities and challenges encountered during the year; (iii) current year operating and financial performance relative to both public guidance and prior year's performance; (iv) significant transactions or accomplishments for the period not included in the goals for the year; (v) our prospects at the end of the year with respect to future growth and performance; and (vi) our positioning at the end of the year with respect to our targeted credit profile. The CEO, with assistance from other members of executive management, takes these factors into consideration as well as the relative contributions of each of our Named Executive Officers to the year's performance in developing recommendations for Named Executive Officer bonus amounts and salary adjustments.

These recommendations for discretionary bonus amounts and salary adjustments for our Named Executive Officers are presented to and discussed with the board of directors of our general partner and the board of managers of Tallgrass Energy Holdings, adjusted as appropriate, and then formally approved by those boards. In several historical instances, the CEO has requested that his bonus amount be reduced, or eliminated.

Long-Term Incentive Awards. We do not make systematic annual grants of LTIP Awards to our Named Executive Officers. We have historically attempted to time the granting of LTIP Awards such that the creation of new long-term incentives coincides with the satisfaction of vesting criteria under existing awards. We have not formally decided on a recurring grant cycle for future grants, but we intend for future grants to provide a balance between a meaningful retention period for us and a visible, reasonable, growth-oriented reward for the executive officer. Under existing LTIP Awards, achievement of performance targets does not shorten the minimum service period requirement.

Application in 2015

At the beginning of 2015, we established the following financial performance objectives for 2015:

- Adjusted EBITDA of $205 - 225 million for the year ended December 31, 2015;
- Distributable Cash Flow of $180 - 195 million for the year ended December 31, 2015;
- Distribution coverage of 1.05 - 1.10x for the year ended December 31, 2015; and
- Growth of approximately 20% in our annualized distribution rate for the calendar year 2015.

We achieved all of these goals:

- Our Adjusted EBITDA for the year ended December 31, 2015 was approximately $252 million;
- Our Distributable Cash Flow for the year ended December 31, 2015 was approximately $220 million;
- Our distribution coverage for the year ended December 31, 2015 was 1.14x; and
- We grew our annualized distribution rate during calendar year 2015 by 32%.

Additionally, our internal qualitative goals included (a) advancing multi-year programs and initiatives and preparing the organization for future growth, and (b) continuing to promote a culture of safety and environmental responsibility throughout the organization.

For 2015, the elements of compensation were applied as described below.

Salary. In 2015, we did not implement material salary increases for our Named Executive Officers.

Cash Bonuses. Based on the CEO's annual performance review and the individual performance of each of our Named Executive Officers, the board of directors of our general partner approved the annual bonuses for our Named Executive Officers reflected in the Summary Compensation Table and notes thereto. Such amounts take into account the performance relative to our 2015 goals; the level of difficulty associated with achieving such objectives; our relative positioning at the end of the year with respect to future growth and performance; the significant transactions or accomplishments for the period not included in the goals for the year; and our positioning at the end of the year with respect to our targeted credit profile. The board of directors of our general partner also considered, on a subjective basis, how well the executive officer performed his or her duties during the year.

Long-Term Incentive Awards. Pursuant to the TEP LTIP, 6,400 equity participation units were granted to Mr. Watkins in 2015 and pursuant to the TEGP LTIP, 35,000 equity participation shares were granted to Mr. Watkins in 2015. Mr. Watkins was the only Named Executive Officer to receive an award under the TEP LTIP or the TEGP LTIP in 2015. As noted below, we believe the substantial direct and indirect equity interests held by our management team, including our Named Executive Officers, in TEGP, Tallgrass Equity and Tallgrass Energy Holdings aligns their interests with those of our unitholders, and is taken into account when considering the level of equity incentives in TEP and TEGP granted to our Named Executive Officers under our compensation programs.

Other Compensation Related Matters

Equity Ownership in TEP. Our Named Executive Officers collectively own substantial equity in the Partnership. Although we encourage our Named Executive Officers to acquire and retain ownership in the Partnership, we do not have a policy requiring maintenance of a specified equity ownership level. Our policies, including our Insider Trading Policy, strongly discourage our Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership. As of February 17, 2016, our Named Executive Officers beneficially owned, in the aggregate, 359,851 of our common units (excluding any unvested LTIP Awards). Based on the closing price of our common units as of February 17, 2016, the value of the equity ownership of these individuals was significantly greater than the combined aggregate salaries and bonuses of these individuals for 2015.

Equity Ownership in TEGP and Tallgrass Energy Holdings. In addition to their direct equity ownership in TEP, some of our Named Executive Officers directly own Class A shares in TEGP and some of our Named Executive Officers indirectly own equity interests in Tallgrass Energy Holdings, Tallgrass Equity and TEGP through Tallgrass KC, an entity controlled by Mr. Dehaemers. As of February 17, 2016, Tallgrass KC owned 27,376,110 Class B Shares in TEGP and 27,376,110 Units in Tallgrass Equity, representing an approximate 17.4% ownership interest in TEGP and Tallgrass Equity, respectively, and also owned 25% of the outstanding equity interests in Tallgrass Energy Holdings. We believe that the substantial direct and indirect equity interests held by our management team in TEGP, Tallgrass Equity and Tallgrass Energy Holdings further aligns their interests with those of our unitholders, and is taken into account when considering the level of equity incentives in TEP and TEGP granted to our Named Executive Officers under our compensation programs.

Recovery of Prior Awards. Except as provided by applicable laws and regulations, we do not have a policy with respect to adjustment or recovery of awards or payments if relevant company performance measures upon which previous awards were based are restated or otherwise adjusted in a manner that would have reduced the size of such award or payment if previously known.

Section 162(m). With respect to the deduction limitations under Section 162(m) of the Code, we are a limited partnership and do not fall within the definition of a "corporation" under Section 162(m).

Change-in-Control Triggers and Termination Payments. The equity participation unit and equity participation share grants to our Named Executive Officers include accelerated vesting triggered upon a change of control, as defined in the respective award agreements. The provision of equity acceleration for defined changes of control help to create a retention tool by assuring the executive that the benefit of the compensation arrangement will be at least partially realized despite the occurrence of an event that could materially alter the executive's employment arrangement. In addition, the employment agreement for Mr. Dehaemers provides for severance in the event his employment is terminated without "cause" or in the event he resigns for "good reason." See *"Potential Payments upon Termination or Change-in-Control."* No other Named Executive Officer has a contractual right to receive severance in the event of a termination of employment.

Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices are designed to provide rewards for short-term and long-term performance, both on an individual basis and at the entity level. In general, optimal financial and operational performance, particularly in a competitive business like ours, requires some degree of risk-taking. Accordingly, the use of compensation as an incentive for performance could potentially cause management and others to take unnecessary or excessive risks to reach the performance thresholds. For us, such risks would primarily attach to the execution of capital expansion projects and asset acquisitions and the realization of associated returns from both, as well as to certain commercial activities conducted in our operational segments.

From a risk management perspective, we monitor and structure our commercial activities in a manner intended to control and minimize the potential for unwarranted risk-taking. See Note 9 – *Risk Management* to our Consolidated Financial Statements in Item 8.—Financial Statements and Supplementary Data. We also monitor and measure our capital projects and acquisitions relative to expectations. In general, we believe our compensation arrangements serve to minimize the incentive for unwarranted risk-taking to achieve short-term, unsustainable results. See *"Compensation Discussion and Analysis – Relation of Compensation Elements to Compensation Objectives."*

In combination with our risk-management practices, we do not believe that risks arising from our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us.

Summary Compensation Table

The following table reflects the total compensation of the principal executive officer, the principal financial officer and the three other most highly compensated executive officers of our general partner for 2015 (the "Named Executive Officers") for services rendered to all Tallgrass-related entities, including the Partnership, TEGP, Tallgrass Management and Tallgrass Development, for the fiscal year ending December 31, 2015.

	Year	Salary (1)	Bonus (2)	Equity Awards (3)	All Other Compensation (4)	Total
David G. Dehaemers, Jr.	2015	$ 300,000	$ 601,000	$ —	$ 27,796	$ 928,796
President, Chief Executive	2014	$ 300,000	$ 251,000	$ —	$ 31,274	$ 582,274
Officer and Director	2013	$ 300,000	$ 100,000	$ —	$ 33,186	$ 433,186
William R. Moler	2015	$ 300,000	$ 551,000	$ —	$ 27,796	$ 878,796
Executive Vice President, Chief	2014	$ 297,118	$ 501,000	$ —	$ 30,436	$ 828,554
Operating Officer and Director	2013	$ 275,000	$ 200,000	$ 874,500	$ 30,578	$ 1,380,078
Gary J. Brauchle	2015	$ 275,000	$ 551,000	$ —	$ 27,665	$ 853,665
Executive Vice President and	2014	$ 272,116	$ 501,000	$ —	$ 26,059	$ 799,175
Chief Financial Officer	2013	$ 250,000	$ 200,000	$ 874,500	$ 26,430	$ 1,350,930
George E. Rider	2015	$ 275,000	$ 551,000	$ —	$ 27,688	$ 853,688
Executive Vice President,	2014	$ 272,116	$ 501,000	$ —	$ 29,930	$ 803,046
General Counsel and Secretary	2013	$ 250,000	$ 200,000	$ 874,500	$ 27,893	$ 1,352,393
Gary D. Watkins	2015	$ 212,322	$ 201,000	$ 1,226,264	$ 22,152	$ 1,661,738
Vice President and						
Chief Accounting Officer						

(1) Reflects actual salary received. Salary adjustments are typically implemented during February, which results in odd amounts actually received by the indicated Named Executive Officer. In our annual report on Form 10-K/A for the year ended December 31, 2014, the Named Executive Officer's adjusted annual salary, rather than the actual amount of salary received, was reported in the salary column for 2014.

(2) Represents discretionary bonuses paid in 2016, 2015 and 2014 based on performance in 2015, 2014 and 2013, respectively. In 2014 and 2015, the amounts also include a $1,000 bonus that was paid to all employees.

(3) The amounts in this column include both equity participation units granted pursuant to the TEP LTIP and equity participation shares granted pursuant to the TEGP LTIP. Of the officers listed above, only Mr. Watkins received a grant under the TEGP LTIP, which occurred during 2015. In addition, 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 under the TEP LTIP and equity participation shares granted under the TEGP LTIP. 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 and equity participation share grants are measured at their grant date fair value. The Equity participation units and equity participation shares are non-participating, therefore the grant date fair value is discounted from the grant date fair value of TEP's common units or TEGP's Class A shares, as appropriate, for the present value of the expected (but non-participating) future dividends during the vesting period. For additional information, see Note 15 – *Equity-Based Compensation* to our Consolidated Financial Statements in Item 8.—Financial Statements and Supplementary Data. These amounts do not correspond to the actual value that will be recognized by the executive.

(4) The amounts in the column include the following: contributions under the 401(k) savings plan (includes $26,500 for Mr. Dehaemers, $26,500 for Mr. Moler, $26,477 for Mr. Brauchle, $26,500 for Mr. Rider, and $21,232 for Mr. Watkins for the year ended December 31, 2015, $30,000 for Mr. Dehaemers, $29,615 for Mr. Moler, $26,366 for Mr. Rider, and $25,519 for Mr. Brauchle for the year ended December 31, 2014, and $30,000 for Mr. Dehaemers, $27,500 for Mr. Moler, $24,923 for Mr. Rider, and $23,460 for Mr. Brauchle for the year ended December 31, 2013) and the dollar value of premiums paid for group life, accidental death and dismemberment insurance.

Narrative Disclosure to Summary Compensation Table

A narrative description of all material factors necessary to an understanding of the information included in the above Summary Compensation Table is included in *"-Compensation Discussion and Analysis"* and in the footnotes to such tables.

Grants of Plan-Based Awards Table

The following table provides information concerning each grant of an award made to a Named Executive Officer for 2015, including, but not limited to awards made under the TEP LTIP and TEGP LTIP. Mr. Watkins was our only Named Executive Officer to receive an LTIP Award during 2015.

	Grant Type	Grant Date	Number of Shares or Units	Grant Date Fair Value of Awards [1]
Gary D. Watkins				
Vice President and	TEP Equity Participation Units	August 1, 2015	6,400 [2]	$ 247,160
Chief Accounting Officer	TEGP Equity Participation Shares	August 1, 2015	35,000 [3]	$ 979,104

(1) The amounts in this column include both EPUs granted pursuant to the TEP LTIP and equity participation shares granted pursuant to the TEGP LTIP. In addition, 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 under the TEP LTIP and equity participation shares granted under the TEGP LTIP. Pursuant to SEC rules, the amounts shown in this 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 and equity participation share grants are measured at their grant date fair value. The EPUs and equity participation shares are non-participating, therefore the grant date fair value is discounted from the grant date fair value of TEP's common units or TEGP's Class A shares, as appropriate, for the present value of the expected (but non-participating) future dividends during the vesting period. For additional information, see Note 15 – *Equity-Based Compensation* to our Consolidated Financial Statements in Item 8.— Financial Statements and Supplementary Data. These amounts do not correspond to the actual value that will be recognized by the executive.

(2) Vesting of the equity participation units is contingent upon TEP quarterly distribution levels and will occur in two parts, with one-half vesting on the later to occur of the TEP Distribution Achievement Date or May 13, 2018, and the remaining half vesting on the later to occur of the TEP Distribution Achievement Date or May 13, 2019. If TEP has not distributed at least $0.6875 on each outstanding common unit for any full quarter ending on or before May 13, 2020, the unvested equity participation units will expire and no vesting will occur.

(3) Vesting of the equity participation shares is contingent upon the later to occur of the TEGP Distribution Achievement Date or May 12, 2019. If TEGP has not distributed at least $0.35 on each outstanding Class A Share for any full quarter ending on or before May 12, 2020, the unvested equity participation shares will expire and no vesting will occur.

Outstanding Equity Awards at Fiscal Year-End

The following table reflects the outstanding equity awards of our Named Executive Officers as of December 31, 2015 under the TEP LTIP.

	Equity Participation Unit Awards (1)					
	Number of EPU Awards That Have Not Vested(2)		Market Value of EPU Awards That Have Not Vested(3)	Number of Unearned EPUs That Have Not Vested		Market or Payout Value of Unearned EPUs That Have Not Vested
David G. Dehaemers, Jr.	—	$	—	—	$	—
William R. Moler	33,333	$	1,373,653	—	$	—
Gary J. Brauchle.................................	33,333	$	1,373,653	—	$	—
George E. Rider..................................	33,333	$	1,373,653	—	$	—
Gary D. Watkins.................................	16,666	$	686,806	6,400	$	263,744

(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 provide for the settlement of the EPUs in common units.

(2) Vesting of the EPUs is contingent upon the later of the Pony Express System in-service date or May 13, 2017. The Pony Express System was placed in service in October 2014.

(3) Reflects the closing price of $41.21 per TEP common unit at December 31, 2015.

(4) Vesting will occur in two parts, with one-half vesting on the later to occur of the TEP Distribution Achievement Date or May 13, 2018, and one-half vesting on the later to occur of the TEP Distribution Achievement Date or May 13, 2019. If TEP has not distributed at least $0.6875 on each outstanding common unit for any full quarter ending on or before May 13, 2020, the unvested EPUs will expire and no vesting will occur.

The following table reflects all outstanding equity awards of our named executive officers as of December 31, 2015 under the TEGP LTIP.

	Equity Participation Share Awards (1)					
	Number of Equity Participation Share Awards That Have Not Vested		Market Value of Equity Participation Share Awards That Have Not Vested	Number of Unearned Equity Participation Shares That Have Not Vested (2)		Market or Payout Value of Unearned Equity Participation Shares That Have Not Vested (3)
David G. Dehaemers, Jr.	—	$	—	—	$	—
William R. Moler	—	$	—	—	$	—
Gary J. Brauchle.................................	—	$	—	—	$	—
George E. Rider..................................	—	$	—	—	$	—
Gary D. Watkins.................................	—	$	—	35,000	$	558,950

(1) The plan administrator may make grants of equity participation shares under the plan containing such terms as the plan administrator shall determine, including the period over which equity participation shares 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 equity participation shares set forth above were granted provide for the settlement of the equity participation shares in TEGP Class A Shares.

(2) Vesting of the equity participation shares is contingent upon the later to occur of the TEGP Distribution Achievement Date or May 12, 2019. If TEGP has not distributed at least $0.35 on each outstanding Class A Share for any full quarter ending on or before May 12, 2020, the unvested equity participation shares will expire and no vesting will occur.

(3) Reflects the closing price of $15.97 per TEGP Class A share at December 31, 2015.

Units Vested

The following table sets forth certain information regarding the vesting of TEP LTIP Awards during the fiscal year ended December 31, 2015. No TEGP Equity Participation Share Awards vested during 2015.

	Number of Equity Participation Units Acquired on Vesting [(1)]	Value Realized on Vesting [(2)]
David G. Dehaemers, Jr. *President, Chief Executive Officer and Director*	—	$ —
William R. Moler *Executive Vice President, Chief Operating Officer and Director*	16,667	$ 809,350
Gary J. Brauchle *Executive Vice President and Chief Financial Officer*	16,667	$ 809,350
George E. Rider *Executive Vice President, General Counsel and Secretary*	16,667	$ 809,350
Gary D. Watkins *Vice President and Chief Accounting Officer*	8,334	$ 404,699

(1) Represents the gross number of EPUs that vested during the year ended December 31, 2015. The actual number of EPUs delivered to the Named Executive Officers was, in some cases, less than the number shown in the above table due to the Named Executive Officers' option to net out common units to cover a portion of applicable tax withholding obligations.

(2) The stated value realized upon vesting is computed by multiplying the closing market price ($48.56) of our common units on the date they vested (May 13, 2015) by the number of units that vested.

Pension Benefits

We sponsor a 401(k) plan that is available to all employees, but we do not maintain a pension or defined benefit program.

Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans

We do not have a nonqualified deferred compensation plan or program for our officers or employees.

Employment Agreement

On May 17, 2013, Mr. Dehaemers entered into an amended and restated employment agreement with Tallgrass Management, our general partner, and certain affiliated entities pursuant to which he agreed to serve as our 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, (ii) reimbursement for all ordinary and necessary out-of-pocket expenses incurred by Mr. Dehaemers, and (iii) a policy of director and officer 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."*

Potential Payments upon Termination or Change-in-Control

Termination

The employment agreement for Mr. Dehaemers provides that in the event his employment is terminated without "cause" or in the event he resigns for "good reason" he will receive: (i) a severance payment equal to $900,000, payable in a lump sum within 60 days after the termination of his employment; and (ii) directors and officers liability insurance coverage for so long as he is subject to any claim arising from his employment by the Partnership and its Affiliates. In addition, upon any such termination, Mr. Dehaemers would receive payments related to his accrued and unpaid expenses, salary and benefits. Under Mr. Dehaemers' employment agreement:

- "Cause" means (i) his conviction of, or plea of nolo contendere to, any crime or offense constituting a felony under applicable law; (ii) his commission of fraud or embezzlement against Tallgrass 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 the entity with ultimate control over our general partner; (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 our general partner or certain affiliates of Tallgrass Management, 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 our general partner or certain affiliates of Tallgrass Management of a material provision of the applicable operating agreements of such entities that has a material and adverse effect on Mr. Dehaemers.

Other than the payments to Mr. Dehaemers pursuant to his employment agreement as described above, we are not obligated to make any cash payment or provide any benefit to our Named Executive Officers if their employment is terminated by us or by the Named Executive Officer, other than the payment of accrued and unpaid expenses, salary and benefits. In addition, any LTIP Awards that have not vested and/or become exercisable are terminated upon the termination of such Named Executive Officer's employment.

Change in Control

Employment Agreement. Upon a change in control, the employment agreement of Mr. Dehaemers generally does not provide for termination or severance benefits or payments in addition to those described above.

LTIP Award Agreements. In addition to the foregoing payments to Mr. Dehaemers pursuant to his employment agreement, the TEP LTIP Awards and TEGP LTIP Awards held by our Named Executive Officers typically provide for acceleration of vesting in connection with a change in control. The TEP LTIP Awards held by our Named Executive Officers vest and/or become exercisable in full upon a "change in control" of us or our general partner and the TEGP LTIP Awards held by our Named Executive Officers vest and/or become exercisable in full upon a "change in control" of TEGP or TEGP's general partner.

Under the TEP LTIP, "change of control" means the occurrence of one or more of the following events:

- any Person or group, other than Tallgrass Equity or its affiliates, becomes the owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of (A) the combined voting power of the equity interests in our general partner, or (B) the general partner interests in TEP (excluding incentive distribution rights);
- the limited partners of TEP approve, in one or a series of transactions, a plan of complete liquidation of TEP; or
- the sale or other disposition by TEP of all or substantially all of its assets in one or more transactions to any person other than our general partner or its affiliates.

Under the TEGP LTIP, "change of control" means the occurrence of one or more of the following events:

- any Person or group, other than Tallgrass Energy Holdings or its affiliates, becomes the owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of (A) the combined voting power of the equity interests in TEGP Management or (B) the general partner interests in TEGP;
- the limited partners of TEGP approve, in one or a series of transactions, a plan of complete liquidation of TEGP; or
- the sale or other disposition by TEGP of all or substantially all of its assets in one or more transactions to any person other than TEGP Management or an affiliate of the TEGP Management.

The following table sets forth the value of outstanding LTIP Awards that would have vested and/or become exercisable for each of the Named Executive Officers under the TEP LTIP and TEGP LTIP if a change in control occurred on December 31, 2015.

	Upon a Change in Control [(1)]
David G. Dehaemers, Jr.	
TEP LTIP	$ —
TEGP LTIP	$ —
William R. Moler	
TEP LTIP	$ 1,373,653
TEGP LTIP	$ —
Gary J. Brauchle	
TEP LTIP	$ 1,373,653
TEGP LTIP	$ —
George E. Rider	
TEP LTIP	$ 1,373,653
TEGP LTIP	$ —
Gary D. Watkins	
TEP LTIP	$ 686,806
TEGP LTIP	$ 558,950

(1) The stated value upon a change in control is computed by assuming that a triggering change of control occurred on December 31, 2015 and multiplying the closing market price (TEP: $41.21 and TEGP: $15.97) of the relevant units and shares on such date by the number of units and shares that would have vested.

Confidentiality, Non-Compete and Non-Solicitation Arrangements

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

Compensation of Directors

Officers or employees of Tallgrass Development 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 Tallgrass Development or its affiliates or affiliated with EMG or Kelso 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.

The following table sets forth certain information with respect to our non-employee director compensation during the year ended December 31, 2015.

Name and Principal Position	Fees Earned or Paid in Cash [(1)]	EPU Awards	Non-Equity Incentive Plan Compensation	Total
Terrance D. Towner	$ 45,000	$ —	$ —	$ 45,000
Roy N. Cook	$ 50,000	$ —	$ —	$ 50,000
Jeffrey R. Armstrong	$ 40,000	$ —	$ —	$ 40,000

(1) Includes cash retainer, meeting fees and committee chair fees paid during the year ended December 31, 2015, regardless of the period during which the compensation was earned.

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.

Compensation Report of the Board of Directors

The Board of Directors of our general partner has reviewed and discussed the compensation discussion and analysis contained in this Annual Report on Form 10-K with management and, based on that review and discussion, has recommended that the compensation discussion and analysis be included in this Annual Report for the year ended December 31, 2015 for filing with the SEC.

David G. Dehaemers, Jr.
William R. Moler
Frank J. Loverro
Stanley de J. Osborne
Jeffrey A. Ball
John T. Raymond
Terrance D. Towner
Roy N. Cook
Jeffrey R. Armstrong

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 February 10, 2016 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.

Percentage of total units to be beneficially owned is based on 67,162,232 common units outstanding as of February 10, 2016.

Name of Beneficial Owner [(1)]	Common Units Beneficially Owned [(2)]	Percentage of Common Units Beneficially Owned
Tallgrass Energy Holdings [(3)]	32,873,480	48.95%
OppenheimerFunds, Inc.[(4)]	4,263,391	6.35%
Kayne Anderson Capital Advisors, L.P.[(5)]	3,930,228	5.85%
David G. Dehaemers, Jr. [(6)]	300,047	*
William R. Moler [(7)]	14,428	*
Gary J. Brauchle [(8)]	25,780	*
George E. Rider	12,928	*
Gary D. Watkins	6,668	*
Frank J. Loverro	—	—
Stanley de J. Osborne	—	—
Jeffrey A. Ball	20,000	*
John T. Raymond	100,000	*
Roy N. Cook	50,000	*
Terrance D. Towner	18,000	*
Jeffrey R. Armstrong	1,000	*
All directors and executive officers as a group (13 persons)	559,911	*

* Less than 1%.

(1) Unless otherwise indicated, the address for all beneficial owners in this table is c/o Tallgrass Energy Partners, LP, 4200 W. 115th Street, Suite 350, Leawood, Kansas 66211, Attn: General Counsel.

(2) This column reflects the number of TEP common units held of record or owned through a bank, broker or other nominee. The common units of TEP presented as being beneficially owned by our general partner's directors and executive officers do not include the TEP common units held by Tallgrass Equity that may be attributable to such directors and officers based on their indirect ownership of Tallgrass Equity.

(3) Consists of common units held of record by (i) Tallgrass Equity and (ii) Tallgrass Operations. Tallgrass Energy Holdings is the sole member of TEGP Management, LLC, TEGP's general partner. TEGP is the managing member of Tallgrass Equity. As such, Tallgrass Energy Holdings has the sole voting and dispositive power with respect to the common units owned by Tallgrass Equity. Tallgrass Energy Holdings, as the general partner of Tallgrass Development, which is the sole owner of Tallgrass Operations, also has the sole voting and dispositive power with respect to the common units owned by Tallgrass Operations. Tallgrass Energy Holdings is 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 Energy Holdings may be deemed to beneficially own the common units owned by Tallgrass Equity and Tallgrass Operations; however, each disclaims beneficial ownership.

(4) As reported on Schedule 13G filed with the SEC on February 5, 2016. Consists of common units of record by OppenheimerFunds, Inc. OppenheimerFunds, Inc. disclaims beneficial ownership pursuant to Rule 13d-4 of the Exchange Act of 1934. The business address for this person is Two World Financial Center, 225 Liberty Street, New York, New York 10281.

(5) As reported on Schedule 13G filed with the SEC on January 27, 2016. Kayne Anderson Capital Advisors, L.P. is the general partner (or general partner of the general partner) of the limited partnerships and investment adviser to the other accounts. Richard A. Kayne is the controlling shareholder of the corporate owner of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. Mr. Kayne is also a limited partner of each of the limited partnerships and a shareholder of the registered investment company. Kayne Anderson Capital Advisors, L.P. disclaims beneficial ownership of the units reported, except those units attributable to it by virtue of its general partner interests in the limited partnerships. Mr. Kayne disclaims beneficial ownership of the units reported, except those units held by him or attributable to him by virtue of his limited partnership interests in the limited partnerships, his indirect interest in the interest of Kayne Anderson Capital Advisors, L.P. in the limited partnerships, and his ownership of common stock of the registered investment company. The business address for Kayne Anderson Capital Advisors, L.P. is 1800 Avenue of the Stars, Third Floor, Los Angeles, California 90067.

(6) David G. Dehaemers, Jr. indirectly owns the common units through the David G. Dehaemers, Jr. Revocable Trust, dated April 26, 2006, for which Mr. Dehaemers serves as Trustee.

(7) William R. Moler indirectly owns the common units through the William R. Moler Revocable Trust, under a trust agreement dated August 29, 2013, for which Mr. Moler serves as Trustee.

(8) Gary J. Brauchle indirectly owns the common units through the Brauchle Revocable Trust, under trust agreement dated April 10, 2014, for which Mr. Brauchle serves as a Trustee.

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, 2015:

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)	1,324,961	$ 24.11	8,675,039
Equity compensation plans not approved by security holders (2)	—	$ —	—
Total	1,324,961	$ 24.11	8,675,039

(1) Amounts shown represent equity participation unit awards outstanding under the TEP LTIP as of December 31, 2015. 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 are no equity compensation plans in place pursuant to which TEP common units may be issued except for the TEP LTIP.

For additional information regarding the TEP LTIP, see Note 15 – *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 February 17, 2016, Tallgrass Development owned 12,873,480 common units representing approximately 19.17% of our outstanding limited partner common units and Tallgrass Equity owned 20,000,000 common units representing approximately 29.78% of our outstanding limited partner common units. In addition, our general partner owns 834,391 general partner units representing an approximate 1.23% 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.

Distributions of available cash to our general partner and its affiliates. We will generally make distributions of available cash to common unitholders pro rata (including Tallgrass Development as the holder of an aggregate of 12,873,480 common units) and to our general partner as follows: (1) an approximate 1.23% with respect to its general partner units and (2) as distributions of available cash exceed the MQD and other higher target levels specified in our partnership agreement, increasing percentages of distributions with respect to its IDRs, 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 $38.4 million on their common units.

Payments to our general partner and its affiliates. Neither our general partner nor Tallgrass Energy Holdings and its affiliates receive a management fee or other compensation for managing us. Our general partner and Tallgrass Energy Holdings and its affiliates are reimbursed, however, for all direct and indirect expenses incurred on our behalf pursuant to our partnership agreement and the TEP Omnibus Agreement. Neither our partnership agreement nor the TEP Omnibus Agreement limit the amount of expenses for which our general partner or Tallgrass Energy Holdings 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 Tallgrass Development 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.

TEP Omnibus Agreement

Upon the closing of the IPO, we entered into the TEP Omnibus Agreement with Tallgrass Development, its general partner, Tallgrass Energy Holdings, and our general partner that governs our relationship with them regarding the following matters:

- the provision by Tallgrass Energy Holdings to us of certain administrative services and our agreement to reimburse it for such services;
- the provision by Tallgrass Energy Holdings 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;
- 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 Tallgrass Development, if Tallgrass Development decides to sell such assets.

Reimbursement of General and Administrative Expenses

Pursuant to the TEP Omnibus Agreement, Tallgrass Energy Holdings performs, or causes its affiliates to perform, centralized corporate, general and administrative services for us, such as legal, corporate record keeping, 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 Tallgrass Energy Holdings and its affiliates are made prior to cash distributions to our common unitholders. The TEP Omnibus Agreement further provides that we will reimburse Tallgrass Energy Holdings and its affiliates for our allocable portion of the premiums on any insurance policies covering our assets. We anticipate reimbursement to Tallgrass Energy Holdings and its affiliates will vary with the size and scale of our operations, among other factors.

For the years ended December 31, 2015, 2014 and 2013, we reimbursed Tallgrass Energy Holdings $37.5 million, $23.5 million and $20.1 million, respectively, pursuant to the TEP Omnibus Agreement.

Indemnification

Under the terms of the TEP Omnibus Agreement, Tallgrass Development 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. Tallgrass Development 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 Tallgrass Development under the purchase and sale agreement pursuant to which Tallgrass Development 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 TEP Omnibus Agreement, we have agreed to indemnify Tallgrass Development 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 TEP Omnibus Agreement, Tallgrass Development has granted us a right of first offer, for so long as Tallgrass Development 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 Tallgrass Development 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 Tallgrass Development or any of its affiliates decide to attempt to sell (other than to an affiliate of Tallgrass Development, excluding TEP and its subsidiaries) a ROFO Asset, Tallgrass Development 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 Tallgrass Development or its affiliate and us. If we and Tallgrass Development 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, Tallgrass Development 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 Tallgrass Development 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.

Amendment and Termination

The TEP 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 TEP 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 TEP Omnibus Agreement (other than the indemnification and reimbursement provisions therein) will be terminable by Tallgrass Development, and we will have a 90-day transition period to cease our use of the name "Tallgrass" and related marks.

Acquisitions of Pony Express and Trailblazer from Tallgrass Development

On April 1, 2014, Tallgrass MLP Operations, LLC, a Delaware limited liability company and our wholly-owned subsidiary acquired 100% of the issued and outstanding membership interests in Trailblazer from Tallgrass Operations, LLC, a Delaware limited liability company and wholly-owned direct subsidiary of Tallgrass Development ("Tallgrass Operations"), for total consideration valued at approximately $164 million, pursuant to that certain Contribution and Sale Agreement by and between Tallgrass Development, Tallgrass Operations, and us.

Effective September 1, 2014, we acquired a 33.3% membership interest in Pony Express, from Tallgrass Development for total consideration of approximately $600 million pursuant to that certain Contribution and Transfer Agreement by and between Tallgrass Development, Pony Express, Tallgrass Operations, and us. At closing, we entered into a Second Amended and Restated Limited Liability Company Agreement of Pony Express effective September 1, 2014 with Tallgrass Development and Pony Express, which provides us a minimum quarterly preference payment of $16.65 million through the quarter ending September 30, 2015 with distributions thereafter shared in accordance with the terms of the Second Amended and Restated Limited Liability Company Agreement. In connection with the transaction, Pony Express entered into a Cash Management Agreement effective August 27, 2014, under which cash balances are swept daily and recorded as loans from Pony Express to Tallgrass Development. $270 million of the total consideration was subsequently swept to Tallgrass Development and was recorded as a related party loan which bears interest at Tallgrass Development's incremental borrowing rate. As of September 1, 2014, balances lent to Tallgrass Development under the cash management agreement are classified as related party receivables on our consolidated balance sheet and will be cash settled.

Effective March 1, 2015, TEP acquired an additional 33.3% membership interest in Pony Express from Tallgrass Development for total consideration of approximately $700 million pursuant to that certain Purchase and Sale Agreement by and between Tallgrass Development, Tallgrass Operations and TEP. At closing, TEP, Tallgrass Development and Pony Express entered into a Third Amended and Restated Limited Liability Company Agreement of Pony Express effective March 1, 2015, which provides TEP a minimum quarterly preference payment of $36.65 million through the quarter ending December 31, 2015 with distributions thereafter shared in accordance with the terms of the Third Amended and Restated Limited Liability Company Agreement.

Effective January 1, 2016, TEP acquired an additional 31.3% membership interest in Pony Express from Tallgrass Development for total cash consideration of approximately $475 million and the issuance of 6,518,000 TEP common units, which TEP common units are subject to a call option granted by Tallgrass Operations in favor of TEP, pursuant to that certain Contribution and Transfer Agreement by and between Tallgrass Development, Tallgrass Operations and TEP.

Competition

Under our partnership agreement, Tallgrass Development and its affiliates are expressly permitted to compete with us. Tallgrass Development 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 is party to a terminal lease and operating agreement with Tallgrass Sterling Terminal, LLC ("Sterling Terminal"), which is an indirect wholly-owned subsidiary of Tallgrass Development, pursuant to which Pony Express leases approximately 1.3 million barrels of crude oil storage and Sterling Terminal provides associated crude oil terminaling services. Pony Express pays Sterling Terminal a fixed monthly charge of $942,000 per month, plus a volumetric charge of $0.07 per barrel for each barrel delivered to the terminal in excess of 9,424,000 per month, subject in both cases to an annual 2% escalator. The initial five-year term of the agreement expires in May 2020. During 2015, Pony Express paid Sterling Terminal $7.6 million pursuant to the agreement.

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 the years ended December 31, 2015, 2014 and 2013, he received cash compensation of $309,907, $348,120 and $235,000, respectively, and standard employee benefits of approximately $18,619, $17,424 and $14,400, respectively. For the year ended December 31, 2013, he was awarded 20,000 unvested EPUs with a grant date value of $17.49 per EPU on terms consistent with all eligible employees.

Zach Rider, a manager of corporate development, is the son of George Rider, the Executive Vice President, General Counsel and Secretary of TEP GP. For the years ended December 31, 2015, 2014 and 2013, he received cash compensation of $179,357, $159,846 and $70,192, respectively, and standard employee benefits of approximately $9,977, $13,747 and $11,600, respectively. For the year ended December 31, 2015, he was awarded 3,800 unvested EPUs with a grant date value of $38.62 per EPU on terms consistent with all eligible employees. For the year ended December 31, 2013, he was awarded 5,000 unvested EPUs with a grant date value of $17.49 per EPU on terms consistent with all eligible employees.

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

The board of directors of our general partner has adopted a related party transactions policy (the "Policy"), which supplements the conflict of interest provisions in our code of business conduct and ethics. According to the Policy, a "Related Party Transaction" is an actual or proposed transaction, arrangement or relationship (or any series of similar transactions, arrangements or relationships) in which (a) the Partnership, our general partner or any of the Partnership's subsidiaries (collectively, the "Partnership Group") was, is or will be a participant, (b) the amount involved exceeds $120,000, and (c) in which any Related Party had, has or will have a direct or indirect material interest. The Policy's definition of a "Related Party" is in line with the definition set forth in the instructions to Item 404(a) of Regulation S-K promulgated by the SEC. Transactions resolved under the conflicts provisions of our partnership agreement are not required to be reviewed or approved under the policy.

Under the Policy, the General Counsel and Chief Financial Officer or Chief Accounting Officer are responsible for determining whether a Related Party Transaction requires the approval of the Audit Committee. The Audit Committee is responsible for evaluating and assessing a proposed transaction based on the relevant facts and circumstances, including comparing the terms of the proposed transaction to the terms available to unrelated third parties. The Audit Committee shall approve only those Related Party Transactions that are either (i) on terms no less favorable to the Partnership Group than those generally being provided to or available from unrelated third parties or (ii) are fair and reasonable to the Partnership Group, taking into account the totality of the relationships between the parties involved.

If the General Counsel determines it is impractical or undesirable to wait until an Audit Committee meeting to consummate a Related Party Transaction, the chairman of the Audit Committee may review and approve the Related Party Transaction in accordance with the procedures set forth in the Policy. However, any such approval (and its rationale) must be reported to the Audit Committee at the next regularly scheduled meeting. A Related Party Transaction entered into without pre-approval of the Audit Committee shall not be deemed to violate the Policy, or be invalid or unenforceable, so long as the transaction is brought to the Audit Committee as promptly as reasonably practical after it is entered into and is subsequently ratified by the Audit Committee. If the Audit Committee determines not to ratify a Related Party Transaction that has been commenced without approval, the Audit Committee may direct the immediate discontinuation or rescission of the transaction, or modify the transaction to make it acceptable for ratification.

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:

	Year Ended December 31,	
	2015	2014
	(in thousands)	
Audit fees [1]	$ 1,400	$ 1,137
Audit related fees [2]	—	—
Tax fees [3]	495	346
Total	$ 1,895	$ 1,483

(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, including all services rendered for the year ended December 31, 2015.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(2) Financial Statement 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).
3.6	Amendment No. 1, dated February 19, 2015, to Second Amended and Restated Limited Liability Company Agreement of Tallgrass MLP GP, LLC, dated May 17, 2013 (incorporated by reference to Exhibit 3.8 to the Partnership's Annual Report on Form 10-K/A filed on June 6, 2015).
3.7	Third Amended and Restated Limited Liability Company Agreement of Tallgrass Pony Express Pipeline, LLC, dated as of March 1, 2015, by and among Tallgrass Pony Express Pipeline, LLC, Tallgrass Operations, LLC, and Tallgrass PXP Holdings, LLC (incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K filed on March 2, 2015).
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	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).

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	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).
10.8	Amendment No. 1, dated June 25, 2014, to the 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 10.1 to the Partnership's Current Report on Form 8-K filed on June 30, 2014).
10.9	Amendment No. 2 to Credit Agreement, dated as of November 24, 2015, 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 10.1 to the Partnership's Current Report on Form 8-K filed on November 30, 2015).
10.10*	Amendment No. 3 to Credit Agreement, dated January 11, 2016, by and among Tallgrass Energy Partners, LP, Barclays Bank PLC, as administrative agent, and a syndicate of lenders named therein.
10.11	Contribution and Sale Agreement, dated April 1, 2014, by and between Tallgrass Energy Partners, LP and Tallgrass Operations, LLC, and for certain limited purposes, Tallgrass Development, LP (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on April 2, 2014).
10.12	Contribution and Transfer Agreement, dated September 1, 2014, by and among Tallgrass Energy Partners, LP, Tallgrass Operations, LLC and Tallgrass Pony Express Pipeline, LLC, and for certain limited purposes, Tallgrass Development, LP (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on September 8, 2014).
10.13	Purchase and Sale Agreement, dated as of March 1, 2015, by and among Tallgrass Energy Partners, LP, Tallgrass Development, LP and Tallgrass Operations, LLC (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on March 2, 2015).
10.14*	Contribution and Transfer Agreement, dated January 1, 2016, by and among Tallgrass Energy Partners, LP, Tallgrass Operations, LLC, and for certain limited purposes, Tallgrass Development, LP.
10.15	Transfer, Purchase and Sale Agreement, dated as of December 16, 2015, by and between Whiting Oil and Gas Corporation, BNN Western, LLC and BNN Redtail, LLC (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on December 16, 2015).
12.1*	Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries of Tallgrass Energy Partners, LP.
23.1*	Consent of PricewaterhouseCoopers LLP.
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 of compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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

By: /s/ David G. Dehaemers, Jr.

David G. Dehaemers, Jr.

President and Chief Executive Officer of Tallgrass MLP GP, LLC (the general partner of Tallgrass Energy Partners, LP)

Date: February 17, 2016

SIGNATURES

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)	February 17, 2016
/s/ Gary J. Brauchle Gary J. Brauchle	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 17, 2016
/s/ Gary D. Watkins Gary D. Watkins	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 17, 2016
/s/ Frank J. Loverro Frank J. Loverro	Director	February 17, 2016
/s/ Stanley de J. Osborne Stanley de J. Osborne	Director	February 17, 2016
/s/ Jeffrey A. Ball Jeffrey A. Ball	Director	February 17, 2016
/s/ John T. Raymond John T. Raymond	Director	February 17, 2016
/s/ William R. Moler William R. Moler	Director	February 17, 2016
/s/ Terrance D. Towner Terrance D. Towner	Director	February 17, 2016
/s/ Roy N. Cook Roy N. Cook	Director	February 17, 2016
/s/ Jeffrey R. Armstrong Jeffrey R. Armstrong	Director	February 17, 2016

Exhibit 10.10

AMENDMENT No. 3 TO CREDIT AGREEMENT

This AMENDMENT No. 3 (this "Third Amendment"), dated January 11, 2016, to the Credit Agreement referred to below by and among Tallgrass Energy Partners, LP, a Delaware limited partnership (the "Borrower"), the other Loan Parties party hereto (collectively, the "Grantors"), the Lenders party hereto, and Barclays Bank PLC, as administrative agent (in such capacity, the "Administrative Agent") and collateral agent (in such capacity, the "Collateral Agent").

RECITALS

WHEREAS, the Borrower, the several Lenders parties thereto, the Issuing Banks party thereto, the Swing Line Lenders party thereto and the Administrative Agent and Collateral Agent have entered into that certain Credit Agreement, dated as of May 17, 2013, as amended by Amendment No. 1 to Credit Agreement, dated as of June 25, 2014, among the Borrower, the several Lenders party thereto, the Issuing Banks party thereto, the Swing Line Lenders party thereto and the Administrative Agent and Collateral Agent, and Amendment No. 2 to Credit Agreement, dated as of November 24, 2015, among the Borrower, the other Loan Parties party thereto, the Lenders party thereto, the Issuing Banks party thereto, the Swing Line Lenders party thereto and the Administrative Agent and Collateral Agent (together with the exhibits and schedules attached thereto, as amended, restated, supplemented or otherwise modified prior to the date hereof, the "Credit Agreement"; capitalized terms used but not defined herein shall have the meanings assigned to them in the Credit Agreement);

WHEREAS, the Borrower desires to be able to repurchase certain common Equity Interests in the Borrower issued to one of Development's Wholly-Owned Subsidiaries as part of the consideration for the purchase of an additional Equity Interest in Pony Express, as described in more detail in this Third Amendment; and

WHEREAS, the Required Lenders party hereto, the Administrative Agent and the Collateral Agent are willing, on the terms and subject to the conditions set forth below, to consent to the amendment of the Credit Agreement as provided herein.

NOW, THEREFORE, in consideration of the covenants and agreements contained herein, as well as other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

ARTICLE I

DEFINITIONS

SECTION 1.1 Certain Definitions. Capitalized terms used (including in the preamble and recitals hereto) but not defined herein shall have the meanings assigned to such terms in the Credit Agreement. As used in this Third Amendment:

"Administrative Agent" is defined in the preamble hereto.

"Borrower" is defined in the preamble hereto.

"Collateral Agent" is defined in the preamble hereto.

"Credit Agreement" is defined in the first recital hereto.

"Third Amendment" is defined in the preamble hereto.

"Third Amendment Effective Date" shall mean the date on which the conditions set forth in Article III of this Third Amendment are satisfied or waived.

ARTICLE II

AMENDMENTS TO LOAN DOCUMENTS

Effective as of the Third Amendment Effective Date, the Credit Agreement is hereby amended as follows:

SECTION 2.1 New Defined Terms. Section 1.01 of the Credit Agreement is amended by adding the following definitions in the appropriate alphabetical order:

"***Exercise Price***" shall mean the price per PXP Unit at which the Borrower may exercise the PXP Option, as agreed upon by the Borrower and Tallgrass Operations, and approved by the Conflicts Committee, in connection with the Third Pony Express Acquisition.

"***PXP Option***" shall mean the option granted to the Borrower by Tallgrass Operations in connection with the Third Pony Express Acquisition to repurchase the PXP Units at the Exercise Price, which option may be exercised, from time to time, in whole or in part, during the PXP Option Term.

"***PXP Option Term***" shall mean the eighteen (18) month period commencing on the closing date of the Third Pony Express Acquisition.

"***PXP Units***" shall mean the 6,518,000 common units of the Borrower issued to Tallgrass Operations as part of the consideration for the Third Pony Express Acquisition.

"***Tallgrass Operations***" shall mean Tallgrass Operations, LLC, a Delaware limited liability company and a Wholly-Owned Subsidiary of Development.

"***Third Amendment***" shall mean that certain Amendment No. 3 dated as of January 11, 2016 by and among the Borrower, the other Loan Parties party thereto, the Lenders party thereto and Barclays Bank, PLC, as Administrative Agent and Collateral Agent.

"***Third Amendment Effective Date***" shall have the meaning assigned to the term "Third Amendment Effective Date" in Section 1.1 of the Third Amendment.

"***Third Pony Express Acquisition***" shall mean the acquisition by the Borrower of an additional 31 and 1/3% Equity Interest in Pony Express pursuant to a Permitted Drop-Down Acquisition effective as of January 1, 2016. The consideration for the Third Pony Express Acquisition consisted of a combination of cash and the PXP Units.

SECTION 2.2 Amendment to Section 6.06. Section 6.06(a) of the Credit Agreement is amended by (a) deleting “and” appearing at the end of clause (v) thereof, (b) deleting “.” appearing at the end of clause (vi) thereof and replacing it with “; and” and (c) inserting the following clause (vii) at the end of such Section:

(vii) from time to time during the PXP Option Term and so long as no Default or Event of Default has occurred and is continuing, the Borrower may, pursuant to the terms of the PXP Option, repurchase any or all of the PXP Units; *provided* that the aggregate purchase price for the PXP Units repurchased pursuant to this Section 6.06(a)(vii) does not exceed the lesser of (A) $277,015,000, or (B)(1) the cash proceeds received by the Borrower (net of offering expenses) from the sale of common Equity Interests of the Borrower during the PXP Option Term (other than sales made in connection with Specified Equity Contributions) *less* (2) the amount of proceeds received from the sale of common Equity Interests of the Borrower during the PXP Option Term that are used to purchase, redeem or otherwise acquire the Borrower's Equity Interests pursuant to Section 6.06(a)(v).

ARTICLE III

CONDITIONS TO EFFECTIVENESS

The effectiveness of this Third Amendment (including the amendments contained in Article II) are subject to the satisfaction (or waiver) of the following conditions:

SECTION 3.1 This Third Amendment shall have been duly executed by the Borrower, the Administrative Agent, the Collateral Agent, the Required Lenders and the other Loan Parties, and delivered to the Administrative Agent;

SECTION 3.2 The Administrative Agent shall have received, to the extent invoiced, reimbursement or payment by the Borrower of all reasonable out-of-pocket expenses (including reasonable fees and expenses of counsel for the Administrative Agent) incurred by the Administrative Agent in connection with this Third Amendment;

SECTION 3.3 No Default or Event of Default has occurred and is continuing under the Credit Agreement both before and immediately after giving effect to the transactions contemplated hereby; and

SECTION 3.4 The representations and warranties of the Borrower set forth in Article IV of this Third Amendment are true and correct.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES

To induce the other parties hereto to enter into this Third Amendment, the Borrower represents and warrants to each of the Lenders and the Administrative Agent that, as of the Third Amendment Effective Date and after giving effect to the transactions and amendments to occur on the Third Amendment Effective Date:

(a) This Third Amendment has been duly authorized, executed and delivered by each of the Loan Parties party hereto and constitutes, and the Credit Agreement (after giving effect to this Third Amendment, will (as to the Borrower) constitute, its legal, valid and binding obligation, enforceable against each of the Loan Parties party hereto or thereto in accordance with its terms, except as such enforcement may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance or transfer, moratorium or similar laws affecting creditors' rights generally, and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at law;

(b) The representations and warranties of the Borrower set forth in the Credit Agreement and the other Loan Documents are true and correct on and as of the Third Amendment Effective Date (after giving effect to this Third Amendment), except to the extent that such representations and warranties specifically refer to an earlier date, in which case they shall be true and correct as of such earlier date; and

(c) After giving effect to this Third Amendment and the transactions contemplated hereby, no Default or Event of Default has occurred and is continuing on the Third Amendment Effective Date.

ARTICLE V

EFFECTS ON LOAN DOCUMENTS

Except as specifically amended herein, all Loan Documents shall continue to be in full force and effect and are hereby in all respects ratified and confirmed. The execution, delivery and effectiveness of this Third Amendment shall not operate as a waiver of any right, power or remedy of any Lender or the Administrative Agent under any of the Loan Documents, nor constitute a waiver of any provision of the Loan Documents or in any way limit, impair or otherwise affect the rights and remedies of the Lenders or the Administrative Agent under the Loan Documents. The Borrower and the other Loan Parties acknowledge and agree that, on and after the Third Amendment Effective Date, this Third Amendment shall constitute a Loan Document for all purposes of the Credit Agreement. On and after the Third Amendment Effective Date, each reference in the Credit Agreement to "this Agreement", "hereunder", "hereof", "herein" or words of like import referring to the Credit Agreement, and each reference in the other Loan Documents to "Credit Agreement", "thereunder", "thereof" or words of like import referring to the Credit Agreement shall mean and be a reference to the Credit Agreement as amended by this Third Amendment, and this Third Amendment and the Credit Agreement shall be read together and construed as a single instrument. Nothing herein shall be deemed to entitle the Borrower to a further consent to, or a further waiver, amendment, modification or other change of, any of the terms, conditions, obligations, covenants or agreements contained in the Credit Agreement or any other Loan Document in similar or different circumstances.

ARTICLE VI

MISCELLANEOUS

SECTION 6.1 Expenses. The Borrower agrees to pay all reasonable out-of-pocket costs and expenses incurred by the Administrative Agent in connection with this Third Amendment and any other documents prepared in connection herewith, in each case to the extent required by Section 9.05 of the Credit Agreement. The Borrower hereby confirms that the indemnification provisions set forth in Section 9.05 of the Credit Agreement shall apply to this Third Amendment and such losses, claims, damages, liabilities, costs and expenses (as more fully set forth therein as applicable) which may arise herefrom or in connection herewith.

SECTION 6.2 Amendments; Execution in Counterparts; Severability.

(a) This Third Amendment may not be amended nor may any provision hereof be waived except in accordance with the terms of Section 9.08 of the Credit Agreement; and

(b) In the event any one or more of the provisions contained in this Third Amendment should be held invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions contained herein and therein shall not in any way be affected or impaired thereby (it being understood that the invalidity of a particular provision in a particular jurisdiction shall not in and of itself affect the validity of such provision in any other jurisdiction). The parties shall endeavor in good-faith negotiations to replace the invalid, illegal or unenforceable provisions with valid provisions the economic effect of which comes as close as possible to that of the invalid, illegal or unenforceable provisions.

SECTION 6.3 Reaffirmation. Each of the Loan Parties party to the Guarantee and Collateral Agreement and the other Loan Documents, in each case as amended, supplemented or otherwise modified from time to time, hereby (i) acknowledges and agrees that all of its obligations under the Guarantee and Collateral Agreement and the other Loan Documents to which it is a party are reaffirmed and remain in full force and effect on a continuous basis, (ii) reaffirms (A) each Lien granted by it to the Collateral Agent for the benefit of the Secured Parties and (B) the guaranties made by it pursuant to the Guarantee and Collateral Agreement, (iii) acknowledges and agrees that the grants of security interests by and the guaranties of the Loan Parties contained in the Guarantee and Collateral Agreement and the Mortgages are, and shall remain, in full force and effect after giving effect to the Third Amendment, and (iv) agrees that the Obligations include, among other things and without limitation, the prompt and complete payment and performance by the Borrower when due and payable (whether at the stated maturity, by acceleration or otherwise) of principal and interest on the Loans under the Credit Agreement.

SECTION 6.4 Governing Law; Waiver of Jury Trial; Jurisdiction. THIS THIRD AMENDMENT SHALL BE CONSTRUED IN ACCORDANCE WITH AND GOVERNED BY THE LAW OF THE STATE OF NEW YORK. EACH PARTY HERETO HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVES ANY RIGHT TO TRIAL BY JURY IN ANY LEGAL ACTION OR PROCEEDING RELATING TO THIS THIRD AMENDMENT, THE CREDIT AGREEMENT OR ANY OTHER LOAN DOCUMENT AND FOR ANY COUNTERCLAIM THEREIN. The provisions of Section 9.15 of the Credit Agreement are incorporated herein by reference.

SECTION 6.5 Headings. Section headings in this Third Amendment are included herein for convenience of reference only, are not part of this Third Amendment and are not to affect the construction of, or to be taken into consideration in interpreting, this Third Amendment.

SECTION 6.6 Counterparts. This Third Amendment may be executed by one or more of the parties hereto on any number of separate counterparts, and all of said counterparts taken together shall be deemed to constitute one and the same instrument. Signatures delivered by facsimile or PDF or other electronic means shall have the same force and effect as manual signatures delivered in person.

IN WITNESS WHEREOF, the parties hereto have caused this Third Amendment to be duly executed and delivered by their respective proper and duly authorized officers as of the day and year first above written.

TALLGRASS ENERGY PARTNERS, LP, as Borrower

By: TALLGRASS MLP GP, LLC, its general partner

By: /s/ Gary Brauchle
Name: Gary Brauchle
Title: Executive Vice President and
Chief Financial Officer

TALLGRASS MLP OPERATIONS, LLC, as Grantor

By: /s/ Gary Brauchle
Name: Gary Brauchle
Title: Executive Vice President and
Chief Financial Officer

TALLGRASS INTERSTATE GAS TRANSMISSION, LLC, as Grantor

By: /s/ Gary Brauchle
Name: Gary Brauchle
Title: Executive Vice President and
Chief Financial Officer

TALLGRASS MIDSTREAM, LLC, as Grantor

By: /s/ Gary Brauchle
Name: Gary Brauchle
Title: Executive Vice President and
Chief Financial Officer

TRAILBLAZER PIPELINE COMPANY LLC, as Grantor

By: /s/ Gary Brauchle
Name: Gary Brauchle
Title: Executive Vice President and
Chief Financial Officer

TALLGRASS ENERGY INVESTMENTS, LLC, as Grantor

By: /s/ Gary Brauchle
Name: Gary Brauchle
Title: Executive Vice President and
Chief Financial Officer

TALLGRASS PXP HOLDINGS, LLC, as Grantor

By: /s/ Gary Brauchle
Name: Gary Brauchle
Title: Executive Vice President and
Chief Financial Officer

TALLGRASS ENERGY FINANCE CORP., as Grantor

By: /s/ Gary Brauchle
Name: Gary Brauchle
Title: Executive Vice President and
Chief Financial Officer

BARCLAYS BANK PLC
as Administrative Agent, Collateral Agent and a Lender

By: /s/ Vanessa A. Kurbatskiy
Name: Vanessa A. Kurbatskiy
Title: Vice President

WELLS FARGO BANK, N.A.
as a Lender

By: /s/ Alan W. Wray
Name: Alan W. Wray
Title: Managing Director

BANK OF AMERICA, N.A.
as a Lender

By: /s/ Bryan Heller
Name: Bryan Heller
Title: Director

GOLDMAN SACHS BANK USA
as a Lender

By: /s/ Jerry Li
Name: Jerry Li
Title: Authorized Signatory

ROYAL BANK OF CANADA
as a Lender

By: /s/ Jason S. York
Name: Jason S. York
Title: Authorized Signatory

CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH
as a Lender

By: /s/ Nupur Kumar
Name: Nupur Kumar
Title: Authorized Signatory

By: /s/ Gregory Fantoni
Name: Gregory Fantoni
Title: Authorized Signatory

MORGAN STANLEY BANK, N.A.
as a Lender

By: /s/ Dmitriy Barskiy
Name: Dmitriy Barskiy
Title: Authorized Signatory

COMPASS BANK
as a Lender

By: /s/ Kathleen J. Bowen
Name: Kathleen J. Bowen
Title: Managing Director

TORONTO DOMINION (TEXAS) LLC
as a Lender

By: /s/ Savo Bozic
Name: Savo Bozic
Title: Authorized Signatory

CAPITAL ONE, NATIONAL ASSOCIATION
as a Lender

By: /s/ Matthew L. Molero
Name: Matthew L. Molero
Title: Sr. Vice President

REGIONS BANK
as a Lender

By: /s/ David Valentine
Name: David Valentine
Title: Director

PNC BANK, NATIONAL ASSOCIATION
as a Lender

By: /s/ Jonathan Luchansky
Name: Jonathan Luchansky
Title: Vice President

U.S. BANK NATIONAL ASSOCIATION
as a Lender

By: /s/ Todd S. Anderson
Name: Todd S. Anderson
Title: Vice President

BANK OF TOKYO MITSUBISHI UFJ
as a Lender

By: /s/ Mark Oberreuter

Name: Mark Oberreuter

Title: Vice President

BNP PARIBAS
as a Lender

By: /s/ Matt Worstell
Name: Matt Worstell
Title: Director

By: /s/ Robert J. Smith
Name: Robert J. Smith
Title: Director

THE BANK OF NOVA SCOTIA
as a Lender

By: /s/ Mark Sparrow
Name: Mark Sparrow
Title: Director

ING CAPITAL LLC
as a Lender

By: /s/ Subha Pasumarti
Name: Subha Pasumarti
Title: Managing Director

By: /s/ Cheryl LaBelle
Name: Cheryl LaBelle
Title: Managing Director

CITIZENS BANK, N.A.
as a Lender

By: /s/ Scott Donaldson
Name: Scott Donaldson
Title: Senior Vice President

ABN AMRO CAPITAL USA, LLC
as a Lender

By: /s/ Darrell Holley
Name: Darrell Holley
Title: Managing Director

By: /s/ Beth Johnson
Name: Beth Johnson
Title: Director

SANTANDER BANK, N.A.
as a Lender

By: /s/ David O'Driscoll
Name: David O'Driscoll
Title: Senior Vice President

By: /s/ Puiki Lok
Name: Puiki Lok
Title: Vice President

CADENCE BANK, N.A.
as a Lender

By: /s/ William W. Brown
Name: William W. Brown
Title: Senior Vice President

UMB BANK, N.A.
as a Lender

By: /s/ Jess M. Adams
Name: Jess M. Adams
Title: Vice President

ZB, N.A. dba Amegy Bank
as a Lender

By: /s/ Jill McSorley
Name: Jill McSorley
Title: Senior Vice President

BRANCH BANKING AND TRUST COMPANY
as a Lender

By: /s/ Ryan K. Michael
Name: Ryan K. Michael
Title: Senior Vice President

Exhibit 10.14

CONTRIBUTION AND TRANSFER AGREEMENT

dated as of January 1, 2016

by and between

TALLGRASS ENERGY PARTNERS, LP,

and

TALLGRASS OPERATIONS, LLC

and for certain limited purposes,
TALLGRASS DEVELOPMENT, LP

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DISCLOSURE MATERIALS

EXHIBITS

APPENDICES

CONTRIBUTION AND TRANSFER AGREEMENT

This Contribution and Transfer Agreement (this "Agreement") is made and effective for tax purposes as of January 4, 2016, and effective for all other purposes as of January 1, 2016, by and between Tallgrass Operations, LLC, a Delaware limited liability company ("Operations"), and Tallgrass Energy Partners, LP, a Delaware limited partnership (the "Partnership"). In addition, Tallgrass Development, LP, a Delaware limited partnership ("Development"), is a party to this Agreement for the limited purposes set forth in Articles III, VI and VII.

RECITALS

WHEREAS, Operations owns 6,000,000 common units in Tallgrass Pony Express Pipeline, LLC, a Delaware limited liability company (the "Company"), comprising 33.3% of the issued and outstanding membership interests in the Company, and the Partnership owns the remaining issued and outstanding membership interests in the Company;

WHEREAS, Operations desires to contribute and transfer 5,640,000 common units in the Company (comprising 31.3% of the issued and outstanding membership interests in the Company) (such membership interests in the Company being referred to herein as the "Subject Interest"), to the Partnership (or its designee) pursuant to the terms of this Agreement and the Assignment Agreement, and the Partnership (or its designee) desires to accept and acquire the Subject Interest in accordance with the terms of this Agreement and the Assignment Agreement;

WHEREAS, the Conflicts Committee has previously (i) received an opinion of Evercore Group L.L.C., the financial advisor to the Conflicts Committee (the "Financial Advisor"), that the amount to be distributed and paid by the Partnership pursuant to the Transaction is fair, from a financial point of view, to the Partnership and to the holders of Common Units of the Partnership (other than Operations and its Affiliates) and (ii) found the Transaction to be fair and reasonable to the Partnership and the holders of its Common Units (other than Operations and its Affiliates) and recommended that the board of directors (the "Board of Directors") of Tallgrass MLP GP, LLC, the general partner of the Partnership (the "General Partner"), approve the Transaction and, subsequently, the Board of Directors has approved the Transaction.

NOW, THEREFORE, in consideration of the premises and the respective representations, warranties, covenants, agreements and conditions contained herein, the parties hereto agree as follows:

Article I
DEFINITIONS

Section 1.1 Definitions.

The respective terms defined in this Section 1.1 shall, when used in this Agreement, have the respective meanings specified herein, with each such definition equally applicable to both singular and plural forms of the terms so defined:

"Affiliate," when used with respect to a Person, means any other Person that directly or indirectly Controls, is Controlled by or is under common Control with such first Person; *provided*, *however*, that (i) with respect to Operations, the term "Affiliate" shall exclude the Partnership, the General Partner and the Partnership's subsidiaries and (ii) with respect to the Partnership, the term "Affiliate" shall exclude Operations, Operations' subsidiaries (other than the Partnership and its subsidiaries), Development, and its general partner, Tallgrass Energy Holdings, LLC. No Person shall be deemed an Affiliate of any Person solely by reason of the exercise or existence of rights, interests or remedies under this Agreement.

"Agreement" has the meaning ascribed to such term in the preamble.

"Annual Corrosion Indemnification Deductible Amount" has the meaning ascribed to such term in Section 5.11(b).

"Annual Period" has the meaning ascribed to such term in Section 5.11(b).

"Applicable Law" has the meaning ascribed to such term in Section 3.3(a).

"Assignment Agreement" means the Assignment Agreement substantially in the form of Exhibit A attached hereto, pursuant to which Operations will assign the Subject Interest to PXP Holdings.

"Board of Directors" has the meaning ascribed to such term in the recitals.

"Cash Amount" means $475,000,000.

"Ceiling Amount" has the meaning ascribed to such term in Section 5.11(a).

"Closing" has the meaning ascribed to such term in Section 2.4.

"Closing Date" has the meaning ascribed to such term in Section 2.4.

"Code" means the Internal Revenue Code of 1986, as amended.

"Commission" means the Securities and Exchange Commission.

"Common Units" has the meaning given to such term in the Partnership Agreement.

"Common Unit Quantity" means 6,518,000 Common Units.

"Company" has the meaning ascribed to such term in the recitals.

"Company Group" means the Company and Tallgrass Colorado, together or individually as the context requires.

"Company Material Adverse Effect" means a material adverse effect on or material adverse change in (i) the assets, liabilities, financial condition or results of operations of the Company Group, other than any effect or change

(a) that impacts the crude oil transportation industry generally (including any change in the prices of crude oil or other hydrocarbon products, industry margins or any regulatory changes or changes in Applicable Law or GAAP), (b) in United States or global political or economic conditions or financial markets in general, or (c) resulting from the announcement of the transactions contemplated by this Agreement and the Assignment Agreement and the taking of any actions contemplated by this Agreement or the Assignment Agreement, *provided*, that in the case of clauses (a) and (b), the impact on the Company Group is not materially disproportionate to the impact on similarly situated parties in the crude oil transportation industry, or (ii) the ability of Operations to perform its obligations under this Agreement or to consummate the transactions contemplated by this Agreement.

"Conflicts Committee" means the conflicts committee of the Board of Directors.

"Control" and its derivatives mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

"Corrosion Costs" means any out of pocket costs to repair, replace or remediate anomalies in any part of the PXP Converted Pipeline to the extent (a) such anomalies are identified by ILI tools (i.e., pigs) during the period beginning January 1, 2015 and ending three-years after the Closing Date and (b) such repair, replacement or remediation is reasonably necessitated by external corrosion of the pipeline and would be performed by a reasonably prudent operator.

"Damages" means liabilities and obligations, including all losses, deficiencies, costs, expenses, fines, interest, expenditures, claims, suits, proceedings, judgments, damages, and reasonable attorneys' fees and reasonable expenses of investigating, defending and prosecuting litigation; provided, however, that Damages specifically excludes Corrosion Costs and any conditions, facts or circumstances that relate to or result in Corrosion Costs.

"Deductible Amount" has the meaning ascribed to such term in Section 5.11(a).

"Delaware LLC Act" means the Delaware Limited Liability Company Act, as amended.

"Development" has the meaning ascribed to such term in the preamble.

"Development Indemnified Parties" has the meaning ascribed to such term in Section 5.2.

"Direct Claim" has the meaning ascribed to such term in Section 5.10.

"Disclosure Schedule" has the meaning ascribed to such term in Article III.

"DRULPA" mean the Delaware Revised Uniform Limited Partnership Act.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Exercise Date" has the meaning ascribed to such term in Section 2.3.

"FERC" means the United States Federal Energy Regulatory Commission.

"Financial Advisor" has the meaning ascribed to such term in the recitals.

"GAAP" means generally accepted accounting principles in the United States of America.

"General Partner" has the meaning ascribed to such term in the recitals.

"Governmental Authority" means any federal, state, municipal or other government, governmental court, department, commission, board, bureau, agency or instrumentality.

"Knowledge," as used in this Agreement with respect to a party hereof, means the actual knowledge of that party's designated personnel. The designated personnel for Development, Operations and the Partnership are set forth on Appendix A.

"Lien" means any mortgage, deed of trust, lien, security interest, pledge, conditional sales contract, charge or encumbrance.

"Minimum Claim Amount" has the meaning ascribed to such term in Section 5.11(a).

"Notice" has the meaning ascribed to such term in Section 6.4.

"Operations" has the meaning ascribed to such term in the preamble.

"Option" has the meaning ascribed to such term in Section 2.3.

"Option Exercise Notice" has the meaning ascribed to such term in Section 2.3.

"Option Exercise Period" has the meaning ascribed to such term in Section 2.3.

"Partnership" has the meaning ascribed to such term in the preamble.

"Partnership Agreement" means that certain Amended and Restated Agreement of Limited Partnership of the Partnership, dated May 17, 2013.

"Partnership Indemnified Parties" has the meaning ascribed to such term in Section 5.1.

"Person" means an individual or entity, including any partnership, corporation, association, trust, limited liability company, joint venture, unincorporated organization or other entity.

"Pony Express LLC Agreement" means that certain Third Amended and Restated Limited Liability Company Agreement of the Company effective as of March 1, 2015, by and among Operations, PXP Holdings and the Company.

"PXP Converted Pipeline" means the approximately 430 mile section of natural gas pipeline from Guernsey, Wyoming to Lincoln County, Kansas, which was abandoned by Tallgrass Interstate Gas Transmission, LLC, sold to the Company and converted for use in the Pony Express system.

"PXP Holdings" means Tallgrass PXP Holdings, LLC, a Delaware limited liability company and indirect wholly-owned subsidiary of the Partnership.

"SEC Documents" has the meaning ascribed to such term in Section 4.5.

"Securities Act" means the Securities Act of 1933, as amended.

"Strike Price" has the meaning ascribed in Section 2.3.

"Subject Interest" has the meaning ascribed to such term in the recitals.

"Tallgrass Colorado" means Tallgrass Colorado Pipeline, Inc., a Delaware corporation and subsidiary of the Company.

"Tax" means any and all U.S. federal, state, local or foreign net income, gross income, gross receipts, sales, use, ad valorem, transfer, franchise, capital stock, profits, license, license fee, environmental, customs duty, unclaimed property or escheat payments, alternative fuels, mercantile, lease, service, withholding, payroll, employment, unemployment, social security, disability, excise, severance, registration, stamp, occupation, premium, property (real or personal), windfall profits, fuel, value added, alternative or add on minimum, estimated or other similar taxes, duties, levies, customs, tariffs, imposts or assessments (including public utility commission property tax assessments) imposed by any Governmental Authority, together with any interest, penalties or additions thereto payable to any Governmental Authority in respect thereof or any liability for the payment of any amounts of any of the foregoing types as a result of being a member of an affiliated, consolidated, combined or unitary group, or being a party to any agreement or arrangement whereby liability for payment of such amounts was determined or taken into account with reference to the liability of any other Person.

"Tax Return" means any return, declaration, report, statement, election, claim for refund or other written document, together with all attachments, amendments and supplements thereto, filed with or provided to, or required to be filed with or provided to, a Governmental Authority in respect of Taxes.

"Third Party Indemnity Claim" has the meaning ascribed to such term in Section 5.5(a).

"Transaction" means (1) the contribution and transfer of the Subject Interest and (2) the delivery of the Transaction Proceeds.

"Transaction Proceeds" means (1) the issuance by the Partnership of the Common Unit Quantity, subject to Section 2.3, and (2) the payment by the Partnership of the Cash Amount.

"Transfer Taxes" has the meaning ascribed to such term in Section 2.5.

Section 1.2 Construction.

In constructing this Agreement: (a) the word "includes" and its derivatives means "includes, without limitation" and corresponding derivative expressions; (b) the currency amounts referred to herein, unless otherwise specified, are in United States dollars; (c) whenever this Agreement refers to a number of days, such number shall refer to calendar days unless business days are specified; (d) unless otherwise specified, all references in this Agreement to "Article," "Section," "Disclosure Schedule," "Exhibit," "preamble" or "recitals" shall be references to an Article, Section, Disclosure Schedule, Exhibit, preamble or recitals hereto; and (e) whenever the context requires, the words used in this Agreement shall include the masculine, feminine and neuter and singular and the plural.

ARTICLE II
CONTRIBUTION AND TRANSFER; CLOSING

Section 2.1 Contribution and Transfer.

Upon the terms and subject to the conditions set forth in this Agreement and in the Assignment Agreement, on the Closing Date, Operations shall transfer, assign, contribute and convey the Subject Interest to PXP Holdings, free and clear of all Liens (other than restrictions under applicable federal and state securities laws), and the Partnership shall cause PXP Holdings to accept and acquire the Subject Interest from Operations.

Section 2.2 Transaction Proceeds.

The aggregate amount to be issued and paid by the Partnership shall be the Transaction Proceeds. At the Closing, the Partnership (or its designee) shall deliver the Transaction Proceeds as follows:

(a) A wire transfer of the Cash Amount in immediately available funds paid to Operations or its designee(s); and

(b) The issuance to Operations of a number of Common Units equal to the Common Unit Quantity, subject to Section 2.3.

Section 2.3 Call Option.

Subject to the terms of this Section 2.3, Operations hereby grants the Partnership the option to purchase from Operations a number of Common Units (the "Option") up to the Common Unit Quantity during the eighteen (18) month period following the Closing Date (the "Option Exercise Period") at an exercise price per Common Unit equal to $42.50 (the "Strike Price"). The Option shall be exercisable by the Partnership at any time or from time to time during the Option Exercise Period, by giving notice in writing to Operations (the "Option Exercise Notice"). Each Option Exercise Notice shall be irrevocable and shall designate (i) the date of exercise (the "Exercise Date"), which shall be no less than five (5) nor more than ten (10) business days from the date of notice, and (ii) the number of Common Units to be purchased. On each Exercise Date, (i) the Partnership shall deliver to Operations immediately available funds in an amount equal to the Strike Price multiplied by the number of Common Units being purchased and (ii) Operations shall deliver to the Partnership a certificate representing the number of Common Units being purchased (or if uncertificated, shall direct the transfer agent to transfer on its books such number of Common Units).

Section 2.4 Closing.

The closing (the "Closing") of the contribution and transfer of the Subject Interest and the delivery of the Transaction Proceeds pursuant to this Agreement and the Assignment Agreement will be held on January 4, 2016 (the "Closing Date") at the offices of Development at 4200 W. 115th Street, Suite 350, Leawood, Kansas 66211. At the Closing, (i) Operations shall deliver to the Partnership, or cause to be delivered to the Partnership, the Assignment Agreement duly executed by Operations, (ii) the Partnership shall deliver, or cause to be delivered, to Operations the Transaction Proceeds and the Assignment Agreement duly executed by the Partnership and PXP Holdings, and (iii) Operations shall deliver to the Partnership, or cause to be delivered to the Partnership, a certificate demonstrating non-foreign status of Development meeting the requirements of Section 1445 of the Code; provided, however, if the Closing Date is not a business day, the foregoing may be delivered no later than the next business day following the Closing Date.

Section 2.5 Transfer Taxes.

All transfer, documentary, sales, use, stamp, registration and other similar Taxes and fees arising out of or in connection with the transactions effected pursuant to this Agreement (the "Transfer Taxes") shall be borne by the

Company Group. The Company Group shall file all necessary Tax Returns and other documentation with respect to such Transfer Taxes. If required by Applicable Law, Operations and the Partnership shall, and shall cause its Affiliates to, join in the execution of any such Tax Returns and other documentation.

Section 2.6 **Tax Treatment and Related Covenants.**

(a) Except as otherwise provided in this Section 2.6, the parties acknowledge that the transactions described in this Agreement are properly characterized as transactions described in Sections 721(a) and 731 of the Code and agree to file all Tax Returns in a manner consistent with such treatment.

(b) The Cash Amount shall be treated (A) as a reimbursement of Operations' capital expenditures within the meaning of Treasury Regulation Section 1.707-4(d) to the extent that Operations provides to the Partnership on or before January 15 of the year following the year in which such amount was paid a statement in the form attached as Exhibit B that states the amount of qualifying capital expenditures, the basis for the qualification, and evidence satisfactory to the Partnership documenting the capital expenditures and their qualification, (B) as a "debt-financed transfer" to Operations under Treasury Regulation Section 1.707-5(b), but only as provided in the following sentence, and (C) as the proceeds of a sale by Operations of the Subject Interest to the Partnership to the extent clause (A), clause (B), or any other exception to the "disguised sale" rules under Section 707 and the Treasury Regulations thereunder, are inapplicable, as Operations shall notify the Partnership on or before January 15 of the year following the year in which such amount was paid. No later than on or before January 15 of the year following the year in which such amount was paid, the Partnership shall provide to Operations a calculation of the minimum and maximum amounts that could be treated as qualifying as a "debt-financed transfer" under Treasury Regulation Section 1.707-5(b), based on the Partnership's exercise of its discretion under Treasury Regulation Section 1.163-8T, and no later than January 31 of such year, Operations will inform the Partnership of the amount within that range of minimum and maximum amounts that Operations wishes to treat as qualifying as such a debt-financed transfer. The parties will prepare and file all Tax Returns consistent with the treatment described in this Section 2.6(b), including based upon the amount elected by Operations as a debt-financed transfer. Except with the prior written consent of Operations, the Partnership agrees to act at all times in a manner consistent with such intended treatment, including, if required, disclosing the distribution of such amounts in accordance with the requirements of Treasury Regulation Section 1.707-3(c)(2).

(c) The parties acknowledge that Operations is disregarded for federal income tax purposes as an entity apart from Development pursuant to Treasury Regulation Section 301.7701-2(c)(2)(i); accordingly, references to Operations in this Section 2.6 include Development as the context requires.

ARTICLE III
REPRESENTATIONS AND WARRANTIES OF DEVELOPMENT AND OPERATIONS

Development and Operations, jointly and severally, hereby represent and warrant to the Partnership that, except as disclosed in the disclosure schedules delivered to the Partnership on the date of this Agreement (collectively, the "Disclosure Schedule") (it being understood that any information set forth on any Disclosure Schedule shall be deemed to apply to and qualify only the section or subsection of this Agreement to which it corresponds in number, unless it is reasonably apparent on its face that such information is relevant to other sections or subsections of this Agreement). The representations and warranties set forth in this Article III are further qualified in all respects by all information set forth or contained in (i) the disclosure schedules delivered to the Partnership in connection with the transactions contemplated by that certain (a) Contribution and Transfer Agreement dated as of September 1, 2014, among the Partnership, Operations and Development and (b) Purchase and Sale Agreement dated as of March 1, 2015, among the

Partnership, Operations and Development, and (ii) the filings made by the Partnership with the Securities and Exchange Commission, including, without limitation, the Partnership's annual report on Form 10-K/A for the year ended December 31, 2014 and its quarterly reports on Form 10-Q for the quarters ended March 31, 2015, June 30, 2015 and September 30, 2015.

Section 3.1 Organization.

(a) Operations is a limited liability company duly formed, validly existing and in good standing under the laws of the State of Delaware and has all requisite limited liability company power and authority to own, operate and lease its properties and assets and to carry on its business as now conducted.

(b) Development is a limited partnership duly formed, validly existing and in good standing under the laws of the State of Delaware and has all requisite limited partnership power and authority to own, operate and lease its properties and assets and to carry on its business as now conducted.

Section 3.2 Authority and Approval.

(a) Each of Development and Operations has full limited partnership or limited liability company, as applicable, power and authority to execute and deliver this Agreement and the Assignment Agreement to which it is party, to consummate the transactions contemplated hereby and thereby and to perform all of the obligations hereof and thereof to be performed by it. The execution and delivery by each of Development and Operations of this Agreement and the Assignment Agreement, the consummation of the transactions contemplated hereby and thereby and the performance of all of the obligations hereof and thereof to be performed by Development and Operations have been duly authorized and approved by all requisite limited partnership or limited liability company, as applicable, action on the part of Development and Operations.

(b) This Agreement has been duly executed and delivered by Development and Operations and constitutes the valid and legally binding obligation of each of Development and Operations, enforceable against it in accordance with its terms, except as such enforcement may be limited by applicable bankruptcy, insolvency, reorganization, moratorium, fraudulent conveyance or other similar laws affecting the enforcement of creditors' rights and remedies generally and by general principles of equity (whether applied in a proceeding at law or in equity). When executed and delivered by each of the parties party thereto, the Assignment Agreement will constitute a valid and legally binding obligation of Operations, enforceable against Operations in accordance with its terms, except as such enforcement may be limited by applicable bankruptcy, insolvency, reorganization, moratorium, fraudulent conveyance or other similar laws affecting the enforcement of creditors' rights and remedies generally and by general principles of equity (whether applied in a proceeding at law or in equity).

Section 3.3 No Conflict; Consents.

Except as set forth on Disclosure Schedule 3.3:

(a) the execution, delivery and performance of this Agreement by Development and Operations does not, and the execution, delivery and performance of the Assignment Agreement by Operations will not, and the fulfillment and compliance with the terms and conditions hereof and thereof and the consummation of the transactions contemplated hereby and thereby will not, (i) violate, conflict with, result in any breach of, or require the consent of any Person under, any of the terms, conditions or provisions of the certificate of formation, limited partnership agreement, limited liability company agreement or equivalent governing instruments of

Development, Operations or the Company Group; (ii) conflict with or violate any provision of any law or administrative rule or regulation or any judicial, administrative or arbitration order, award, judgment, writ, injunction or decree applicable to Development, Operations or the Company Group ("Applicable Law"); (iii) conflict with, result in a breach of, constitute a default under (whether with notice or the lapse of time or both), or accelerate or permit the acceleration of the performance required by, or require any consent, authorization or approval under, or result in the suspension, termination or cancellation of, or in a right of suspension, termination or cancellation of, any indenture, mortgage, agreement, contract, commitment, license, concession, permit, lease, joint venture or other instrument to which Development or Operations is a party or to which either of their respective properties are subject; and

(b) no consent, approval, license, permit, order or authorization of any Governmental Authority or other Person is required to be obtained or made by Operations or the Company with respect to the Subject Interest in connection with the execution, delivery and performance of this Agreement and the Assignment Agreement or the consummation of the transactions contemplated hereby or thereby, except (i) as have been waived or obtained or with respect to which the time for asserting such right has expired or (ii) for those which individually or in the aggregate would not reasonably be expected to have a Company Material Adverse Effect (including such consents, approvals, licenses, permits, orders or authorizations that are not customarily obtained prior to the Closing and are reasonably expected to be obtained in the ordinary course of business following the Closing).

Section 3.4 Title to Subject Interest.

Operations owns, beneficially and of record, the Subject Interest and will convey good title, free and clear of all Liens, to the Subject Interest to the Partnership. The Subject Interest is not subject to any agreements or understandings with respect to the voting or transfer of any of the Subject Interest (except the sale of the Subject Interest contemplated by this Agreement and restrictions under applicable federal and state securities laws). The Subject Interest has been duly authorized and is validly issued, fully paid (to the extent required under the Pony Express LLC Agreement) and nonassessable (except as provided in the Pony Express LLC Agreement and as such nonassessability may be affected by Sections 18-607 and 18-804 of the Delaware LLC Act).

Section 3.5 Litigation.

Except as set forth on Disclosure Schedule 3.5:

(a) There are no civil, criminal or administrative actions, suits, claims, hearings, arbitrations, investigations or proceedings pending or, to Development's and Operations' Knowledge, threatened that (a) question or involve the validity or enforceability of any of Development's or Operations' obligations under this Agreement or the Assignment Agreement or (b) seek (or reasonably might be expected to seek) (i) to prevent or delay the consummation by Development or Operations of the transactions contemplated by this Agreement or the Assignment Agreement or (ii) damages in connection with any such consummation.

(b) Operations is not in violation of any Applicable Law, except as would not, individually or in the aggregate, reasonably be expected to have a Company Material Adverse Effect.

Section 3.6 Brokerage Arrangements.

Operations has not entered (directly or indirectly) into any agreement with any Person that would obligate Operations or any of its Affiliates to pay any commission, brokerage or "finder's fee" or other similar fee in connection with this Agreement, the Assignment Agreement or the transactions contemplated hereby or thereby.

Section 3.7 <u>Investment Intent</u>.

Operations is receiving the Common Unit Quantity for its own account with the present intention of holding such Common Units for investment purposes and not with a view to, or for offer or sale in connection with, any distribution thereof in violation of the Securities Act or state securities laws. Operations does not presently have any contract, undertaking, agreement or arrangement with any Person to sell, transfer or grant participations to such Person or to any third Person, with respect to such Common Units. Operations has such knowledge and experience in financial and business matters that it is capable of evaluating the merits and risk of an investment in such Common Units. Operations acknowledges that such Common Units are not currently registered under the Securities Act or any applicable state securities law and may not be registered in the future, and that such Common Units may not be transferred or sold except pursuant to the registration provisions of the Securities Act or pursuant to an applicable exemption therefrom and pursuant to state securities laws and regulations as applicable. Operations acknowledges that the Partnership has no obligation to register or qualify such Common Units for resale other than as set forth in the Partnership Agreement, and further acknowledges that if an exemption from registration or qualification is available, it may be conditioned on various requirements, including, but not limited to, the time and manner of sale, the holding period for such Common Units, and on requirements relating to the Partnership that are outside of the control of Operations, and that the Partnership is under no obligation and may not be able to satisfy.

Section 3.8 <u>Information</u>.

To the Knowledge of Development and Operations, all information that has been made available to the Partnership, the Conflicts Committee and its advisors by Development, Operations or any of their respective directors, partners, members, officers, employees, agents, advisors or representatives in connection with the evaluation, negotiation and execution of this Agreement and the transactions contemplated hereby is complete and correct in all material respects and does not contain any untrue statement of a material fact or omit to state a material fact necessary in order to make the statements contained therein not misleading in the light of the circumstances under which such statements were made, it being understood and agreed that the Financial Advisor and legal counsel to the Conflicts Committee are not agents, advisors or representatives of Development or Operations.

Section 3.9 <u>Management Projections and Budget</u>.

The projections and budgets identified on <u>Disclosure Schedule 3.9</u>, which were provided to the Partnership (including those provided to the Financial Advisor) by Development and its Affiliates as part of the Partnership's review in connection with this Agreement, were prepared based upon assumptions that Development's management believed to be reasonable as of the date thereof and were consistent with Development management's expectations at the time they were prepared.

ARTICLE IV
<u>REPRESENTATIONS AND WARRANTIES OF THE PARTNERSHIP</u>

The Partnership hereby represents and warrants to Operations as follows:

Section 4.1 <u>Organization and Existence</u>.

The Partnership is a limited partnership duly formed, validly existing and in good standing under the laws of the State of Delaware and has all requisite limited partnership power and authority to own, operate and lease its properties and assets and to carry on its business as now conducted. PXP Holdings is a limited liability company duly formed, validly existing and in good standing under the laws of the State of Delaware and has all requisite limited liability company power and authority to own, operate and lease its properties and assets and to carry on its business as now conducted.

Section 4.2 **Authority and Approval.**

(a) The Partnership has full limited partnership power and authority to execute and deliver this Agreement and the Assignment Agreement, PXP Holdings has full limited liability company power and authority to execute and deliver the Assignment Agreement, and each has full limited partnership or limited liability company power and authority, as applicable, to consummate the transactions contemplated hereby and thereby and to perform all of the obligations hereof and thereof to be performed by it. The execution and delivery of this Agreement and the Assignment Agreement, the consummation of the transactions contemplated hereby and thereby and the performance of all of the obligations hereof and thereof to be performed by the Partnership and PXP Holdings have been duly authorized and approved by all requisite limited partnership and limited liability company action of the Partnership and PXP Holdings, as applicable.

(b) This Agreement has been duly executed and delivered by or on behalf of the Partnership and constitutes the valid and legally binding obligation of the Partnership, enforceable against the Partnership in accordance with its terms, except as such enforcement may be limited by applicable bankruptcy, insolvency, reorganization, moratorium, fraudulent conveyance or other similar laws affecting the enforcement of creditors' rights and remedies generally and by general principles of equity (whether applied in a proceeding at law or in equity). When executed and delivered by each of the parties party thereto, the Assignment Agreement will constitute a valid and legally binding obligation of the Partnership and PXP Holdings, enforceable against the Partnership and PXP Holdings in accordance with its terms, except as such enforcement may be limited by applicable bankruptcy, insolvency, reorganization, moratorium, fraudulent conveyance or other similar laws affecting the enforcement of creditors' rights and remedies generally and by general principles of equity (whether applied in a proceeding at law or in equity).

Section 4.3 **Common Units.**

(a) The issuance by the Partnership of the Common Unit Quantity pursuant to this Agreement and the limited partner interests represented thereby: (i) has been duly authorized by or on behalf of the Partnership pursuant to the Partnership Agreement; (ii) when issued and delivered in accordance with the terms of this Agreement and the Partnership Agreement, will be validly issued, fully paid (to the extent required by the Partnership Agreement) and nonassessable (except as such nonassessability may be affected by Sections 17-303, 17-607 and 17-804 of the DRULPA); and (iii) will be free of any and all Liens and restrictions on transfer, other than restrictions on transfer under the Partnership Agreement, the DRULPA, and applicable state and federal securities laws.

(b) The Partnership's Common Units are listed on the New York Stock Exchange, and the Partnership has not received any notice of delisting.

(c) On the Closing Date, the Common Unit Quantity will have those rights, preferences, privileges and restrictions governing the Common Units as set forth in the Partnership Agreement and Section 2.3 of this Agreement.

Section 4.4 **No Conflict; Consents.**

(a) The execution, delivery and performance of this Agreement by the Partnership does not, and the execution, delivery and performance of the Assignment Agreement by the Partnership and PXP Holdings will not, and the fulfillment and compliance with the terms and conditions hereof and the consummation of the transactions contemplated hereby and thereby will not, (i) violate, conflict with, result in any breach of, or require the consent of any Person under, any of the terms, conditions or provisions of the certificate of limited partnership or limited partnership agreement of the Partnership or the certificate of formation or limited liability company agreement of PXP Holdings; (ii) conflict with or violate any provision of any law or administrative rule or regulation or any judicial, administrative or arbitration order, award, judgment, writ, injunction or decree applicable to the Partnership, PXP Holdings or any property or asset of the Partnership or PXP Holdings; (iii) conflict with, result in a breach of, constitute a default under (whether with notice or the lapse of time or both), or accelerate or permit the acceleration of the performance required by, or require any consent, authorization or approval under, any indenture, mortgage, agreement, contract, commitment, license, concession, permit, lease, joint venture or other instrument to which the Partnership or PXP Holdings is a party or by which it is bound or to which any of its property is subject; and

(b) No consent, approval, license, permit, order or authorization of any Governmental Authority or other Person is required to be obtained or made by or with respect to the Partnership or PXP Holdings in connection with the execution, delivery, and performance of this Agreement or the Assignment Agreement or the consummation of the transactions contemplated hereby and thereby, except as have been waived or obtained or with respect to which the time for asserting such right has expired.

Section 4.5 Periodic Reports.

The Partnership's forms, registration statements, reports, schedules and statements required to be filed by it under the Exchange Act or the Securities Act (all such documents filed prior to the date hereof, collectively the "SEC Documents") have been filed with the Commission on a timely basis. The SEC Documents, including, without limitation, any audited or unaudited financial statements and any notes thereto or schedules included therein, at the time filed (or in the case of registration statements, solely on the dates of effectiveness) (except to the extent corrected by a subsequent SEC Document) (a) did not contain any untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading, (b) complied in all material respects with the applicable requirements of the Exchange Act and the Securities Act, as the case may be, (c) complied as to form in all material respects with applicable accounting requirements and with the published rules and regulations of the Commission with respect thereto, (d) were prepared in accordance with GAAP applied on a consistent basis during the periods involved (except as may be indicated in the notes thereto or, in the case of unaudited statements, as permitted by Form 10-Q of the Commission), and (e) fairly present (subject in the case of unaudited statements to normal and recurring audit adjustments) in all material respects the consolidated financial position of the Partnership and its consolidated subsidiaries as of the dates thereof and the consolidated results of its operations and cash flows for the periods then ended. PricewaterhouseCoopers LLP is an independent registered public accounting firm with respect to the Partnership and has not resigned or been dismissed as an independent registered public accountant of the Partnership.

Section 4.6 Brokerage Arrangements.

The Partnership has not entered (directly or indirectly) into any agreement with any Person that would obligate the Partnership or any of its Affiliates to pay any commission, brokerage or "finder's fee" or other similar fee in connection with this Agreement, the Assignment Agreement or the transactions contemplated hereby or thereby.

Section 4.7 No Registration.

Assuming the accuracy of the representations and warranties of Operations contained in Section 3.7, the issuance of the Common Unit Quantity pursuant to this Agreement is exempt from the registration requirements of the Securities Act, and neither the Partnership nor, to the Knowledge of the Partnership, any authorized representative acting on its behalf has taken or will take any action hereafter that would cause the loss of such exemption. Neither the Partnership nor any of its subsidiaries have, directly or indirectly through any agent, sold, offered for sale, solicited offers to buy or otherwise negotiated in respect of, any "security" (as defined in the Securities Act) that is or will be integrated with the issuance of the Common Unit Quantity in a manner that would require registration under the Securities Act.

Section 4.8 Litigation.

There are no civil, criminal or administrative actions, suits, claims, hearings, arbitrations, investigations or proceedings pending or, or to the Partnership's Knowledge, threatened that (a) question or involve the validity or enforceability of any of the Partnership's or PXP Holdings' obligations under this Agreement or the Assignment Agreement or (b) seek (or reasonably might be expected to seek) (i) to prevent or delay the consummation by the Partnership or PXP Holdings of the transactions contemplated by this Agreement or the Assignment Agreement or (ii) damages in connection with any such consummation.

Section 4.9 Investment Intent.

The Partnership is accepting the Subject Interest for its own account with the present intention of holding the Subject Interest for investment purposes and not with a view to, or for offer or sale in connection with, any distribution thereof in violation of the Securities Act or state securities laws. The Partnership acknowledges that the Subject Interest will not be registered under the Securities Act or any applicable state securities law, and that such Subject Interest may not be transferred or sold except pursuant to the registration provisions of the Securities Act or pursuant to an applicable exemption therefrom and pursuant to state securities laws and regulations as applicable.

ARTICLE V
INDEMNIFICATION

Section 5.1 Indemnification of the Partnership.

Subject to the limitations set forth in this Agreement, Development and Operations, from and after the Closing Date, shall, jointly and severally, indemnify, defend and hold the Partnership, its subsidiaries and their respective securityholders, directors, officers, and employees, and the officers, directors and employees of the General Partner, but otherwise excluding Development, its Affiliates and the Company Group (the "Partnership Indemnified Parties") harmless from and against any and all Damages suffered or incurred by any Partnership Indemnified Party as a result of or arising out of (i) any breach or inaccuracy of a representation or warranty of Development or Operations in this Agreement or the Assignment Agreement, or (ii) any breach of any agreement or covenant on the part of Development, Operations or the Company made under this Agreement or the Assignment Agreement or in connection with the transactions contemplated hereby or thereby. For purposes of this Section 5.1, whether Development or Operations has breached any of its representations and warranties herein shall be determined without giving effect to any qualification as to "materiality" (including the word "material").

Section 5.2 Indemnification of Development.

Subject to the limitations set forth in this Agreement, the Partnership, from and after the Closing Date, shall indemnify, defend and hold Development, its Affiliates (other than any of the Partnership Indemnified Parties) and their respective securityholders, directors, officers, and employees (the "Development Indemnified Parties") harmless from and against any and all Damages suffered or incurred by the Development Indemnified Parties as a result of or arising out of (i) any breach or inaccuracy of a representation or warranty of the Partnership in this Agreement or the Assignment Agreement, or (ii) any breach of any agreement or covenant on the part of the Partnership made under this Agreement or the Assignment Agreement or in connection with the transactions contemplated hereby or thereby. For purposes of this Section 5.2, whether the Partnership has breached any of its representations and warranties herein shall be determined without giving effect to any qualification as to "materiality" (including the word "material").

Section 5.3 Corrosion Costs Indemnification.

Subject to the limitations set forth in Section 5.11(b), Development and Operations shall, jointly and severally, indemnify the Partnership for any and all Corrosion Costs incurred by the Partnership during the three-year period following the Closing Date. Costs of running ILI tools (i.e., pigs) to detect corrosion and other routine maintenance or repair expenditures will not be considered Corrosion Costs and will not be indemnified by Development or Operations.

Section 5.4 Survival.

All the provisions of this Agreement shall survive the Closing, notwithstanding any investigation at any time made by or on behalf of any party hereto, provided that the representations and warranties set forth in Article III and Article IV shall terminate and expire on October 1, 2016, except the representations and warranties of Development and Operations set forth in Section 3.1 (Organization), Section 3.2 (Authority and Approval), Section 3.4 (Title to Subject Interest) and Section 3.6 (Broker Fees) shall survive forever and (d) the representations and warranties of the Partnership set forth in Section 4.1 (Organization and Existence), Section 4.2 (Authority and Approval) and Section 4.6 (Broker Fees) shall survive forever. After a representation and warranty has terminated and expired, no indemnification shall or may be sought pursuant to this Article V on the basis of that representation and warranty by any Person who would have been entitled pursuant to this Article V to indemnification on the basis of that representation and warranty prior to its termination and expiration, provided that in the case of each representation and warranty that shall terminate and expire as provided in this Section 5.4, no claim presented in writing for indemnification pursuant to this Article V on the basis of that representation and warranty prior to its termination and expiration shall be affected in any way by that termination and expiration. The indemnification obligations under this Article V or elsewhere in this Agreement shall apply regardless of whether any suit or action results solely or in part from the active, passive or concurrent negligence or strict liability of the indemnified party. The covenants and agreements entered into pursuant to this Agreement to be performed after the Closing shall survive the Closing.

Section 5.5 Demands.

(a) Each indemnified party hereunder agrees that promptly upon its discovery of facts giving rise to a claim for indemnity under the provisions of this Agreement, including receipt by it of notice of any demand, assertion, claim, action or proceeding, judicial or otherwise, by any third party (such claims for indemnity involving third-party claims being collectively referred to herein as the "Third Party Indemnity Claim"), with respect to any matter as to which it claims to be entitled to indemnity under the provisions of this Agreement, it will give prompt notice thereof in writing to the indemnifying party, together with a statement of such information respecting any of the foregoing as it shall have. Such notice shall include a formal demand for indemnification under this Agreement.

(b) Notwithstanding the foregoing, if the indemnified party fails to notify the indemnifying party thereof in accordance with the provisions of this Agreement in sufficient time to permit the indemnifying party or its counsel to defend against a Third Party Indemnity Claim and to make a timely response thereto, the indemnifying party's indemnity obligation relating to such Third Party Indemnity Claim shall not be relieved except in the event and only to the extent that the indemnifying party is prejudiced or damaged by such failure.

Section 5.6 Right to Contest and Defend.

(a) The indemnifying party shall be entitled, at its cost and expense, to contest and defend by all appropriate legal proceedings any Third Party Indemnity Claim for which it is called upon to indemnify the indemnified party under the provisions of this Agreement; *provided*, that notice of the intention to so contest shall be delivered by the indemnifying party to the indemnified party within thirty (30) days from the date of receipt by the indemnifying party of notice by the indemnified party of the assertion of the Third Party Indemnity Claim. Any such contest may be conducted in the name and on behalf of the indemnifying party or the indemnified party as may be appropriate. Such contest shall be conducted by reputable counsel employed by the indemnifying party and not reasonably objected to by the indemnified party, but the indemnified party shall have the right but not the obligation to participate in such proceedings and to be represented by counsel of its own choosing at its sole cost and expense.

(b) The indemnifying party shall have full authority to determine all action to be taken with respect thereto; *provided*, *however*, that the indemnifying party will not have the authority to subject the indemnified party to any obligation whatsoever, other than the performance of purely ministerial tasks or obligations not involving material expense or injunctive relief. If the indemnifying party does not elect to contest any such Third Party Indemnity Claim, the indemnifying party shall be bound by the result obtained with respect thereto by the indemnified party. If the indemnifying party assumes the defense of a Third Party Indemnity Claim, the indemnified party shall agree to any settlement, compromise or discharge of a Third Party Indemnity Claim that the indemnifying party may recommend and that by its terms obligates the indemnifying party to pay the full amount of the liability in connection with such Third Party Indemnity Claim, which releases the indemnified party completely in connection with such Third Party Indemnity Claim and which would not otherwise adversely affect the indemnified party as determined by the indemnified party in its sole discretion.

(c) Notwithstanding the foregoing, the indemnifying party shall not be entitled to assume the defense of any Third Party Indemnity Claim (and shall be liable for the reasonable fees and expenses of counsel incurred by the indemnified party in defending such Third Party Indemnity Claim) if the Third Party Indemnity Claim seeks an order, injunction or other equitable relief or relief for other than money damages against the indemnified party which the indemnified party reasonably determines, after conferring with its outside counsel, cannot be separated from any related claim for money damages. If such equitable relief or other relief portion of the Third Party Indemnity Claim can be so separated from that for money damages, the indemnifying party shall be entitled to assume the defense of the portion relating to money damages.

Section 5.7 <u>Cooperation</u>.

If requested by the indemnifying party, the indemnified party agrees to cooperate with the indemnifying party and its counsel in contesting any Third Party Indemnity Claim that the indemnifying party elects to contest or, if appropriate, in making any counterclaim against the person asserting the Third Party Indemnity Claim, or any cross-complaint against any person, and the indemnifying party will reimburse the indemnified party for any expenses incurred by it in so cooperating. At no cost or expense to the indemnified party, the indemnifying party shall cooperate with the indemnified party and its counsel in contesting any Third Party Indemnity Claim.

Section 5.8 <u>Right to Participate</u>.

The indemnified party agrees to afford the indemnifying party and its counsel the opportunity to be present at, and to participate in, conferences with all Persons, including Governmental Authorities, asserting any Third Party Indemnity Claim against the indemnified party or conferences with representatives of or counsel for such Persons.

Section 5.9 <u>Payment of Damages and Corrosion Costs</u>.

The indemnification required hereunder shall be made by periodic payments of the amount of Damages or Corrosion Costs in connection therewith within ten (10) days as and when reasonably specific bills are received by, or Damages or Corrosion Costs, as applicable, are incurred and reasonable evidence thereof is delivered to, the indemnifying party. In calculating any amount to be paid by an indemnifying party by reason of the provisions of this

Agreement, the amount shall be reduced by all insurance proceeds and any indemnification reimbursement proceeds received from third parties credited to or received by the indemnified party related to the Damages or Corrosion Costs, as applicable.

Section 5.10 Direct Claim.

Any claim by an indemnified party with respect to any Damages which do not result from a Third Party Indemnity Claim (a "Direct Claim") will be asserted by giving the indemnifying party reasonably prompt written notice thereof, stating the nature of such claim in reasonable detail and indicating the estimated amount, if practicable. The indemnifying party will have a period of ninety (90) days from receipt of such Direct Claim within which to respond to such Direct Claim. If the indemnifying party does not respond within such ninety (90) day period, the indemnifying party will be deemed to have accepted such Direct Claim. If the indemnifying party rejects such Direct Claim, the indemnified party will be free to seek enforcement of its rights to indemnification under this Agreement.

Section 5.11 Limitations on Indemnification.

(a) To the extent that the Partnership Indemnified Parties would otherwise be entitled to indemnification for Damages pursuant to Section 5.1(i), Development and Operations shall be liable only if (i) the Damages with respect to any individual claim exceed $100,000 (the "Minimum Claim Amount") and (ii) the Damages for all claims that exceed the Minimum Claim Amount exceed, in the aggregate, $7,500,000 (the "Deductible Amount"), and then Development and Operations shall be liable only for Damages to the extent of any excess over the Deductible Amount. In no event shall Development's and Operations' aggregate liability to the Partnership Indemnified Parties under Section 5.1 exceed $75,000,000 (the "Ceiling Amount"). Notwithstanding the foregoing, the Deductible Amount and the Ceiling Amount shall not apply to breaches or inaccuracies of representations and warranties contained in Section 3.1, Section 3.2 and Section 3.4.

(b) To the extent that the Partnership would otherwise be entitled to indemnification for Corrosion Costs pursuant to Section 5.3, Development and Operations shall be liable only if the Corrosion Costs exceed, in the aggregate, $1,000,000 (the "Annual Corrosion Indemnification Deductible Amount") during any annual period commencing on the Closing Date or any anniversary thereof (each, an "Annual Period"), and then Development and Operations shall be liable only for Corrosion Costs incurred during any Annual Period to the extent of any excess over the Annual Corrosion Indemnification Deductible Amount. In no event shall Development's and Operations' aggregate liability to the Partnership under Section 5.3 exceed $11,000,000.

(c) Additionally, neither the Partnership, on the one hand, nor Development and Operations, on the other hand, will be liable as an indemnitor under this Agreement for any consequential, incidental, special, indirect or exemplary damages suffered or incurred by the indemnified party or parties except to the extent resulting pursuant to Third Party Indemnity Claims.

Section 5.12 Sole Remedy.

No party shall have liability under this Agreement, the Assignment Agreement or the transactions contemplated hereby or thereby except as is provided in this Article V (other than claims or causes of action arising from fraud).

ARTICLE VI
MISCELLANEOUS

Section 6.1 **Acknowledgements.**

Each party acknowledges that it has relied on the representations and warranties of the other party expressly and specifically set forth in this Agreement, including, in the case of the Partnership, the Disclosure Schedule attached hereto. Such representations and warranties constitute the sole and exclusive representations and warranties of the parties hereto in connection with the transactions contemplated hereby, and the parties hereto understand, acknowledge and agree that all other representations and warranties of any kind or nature, whether expressed, implied or statutory, oral or written, past or present, are specifically disclaimed.

Section 6.2 **Cooperation; Further Assurances.**

Operations and the Partnership shall use their respective commercially reasonable efforts to obtain all approvals and consents required by or necessary for the transactions contemplated by this Agreement and the Assignment Agreement. Each of the parties acknowledges that certain actions may be necessary with respect to the matters and actions contemplated by this Agreement and the Assignment Agreement such as making notifications and obtaining consents or approvals or other clearances that are material to the consummation of the transactions contemplated hereby, and each agrees to take all appropriate action and to do all things necessary, proper or advisable under Applicable Laws and regulations to make effective the transactions contemplated by this Agreement and the Assignment Agreement; *provided, however,* that nothing in this Agreement will require any party hereto to hold separate or make any divestiture not expressly contemplated herein of any asset or otherwise agree to any restriction on its operations or other burdensome condition which would in any such case be material to its assets, liabilities or business in order to obtain any consent or approval or other clearance required by this Agreement or the Assignment Agreement.

Section 6.3 **Expenses.**

Except as otherwise provided herein and regardless of whether the transactions contemplated hereby are consummated, each party shall pay its own expenses incident to this Agreement and all action taken in preparation for carrying this Agreement into effect.

Section 6.4 **Notices.**

Any notice, request, instruction, correspondence or other document to be given hereunder by any party hereto to another party hereto (herein collectively called "Notice") shall be in writing and delivered in person, by courier service requiring acknowledgment of receipt of delivery or by fax, as follows:

If to Development, addressed to:

Tallgrass Development, LP
4200 W. 115th Street, Suite 350
Leawood, KS 66211
Attention: General Counsel
Tel: (913) 928-6010
Fax: (913) 928-6011

with copies (which shall not constitute notice) to:

Baker Botts L.L.P.
98 San Jacinto Blvd., Suite 1500
Austin, Texas 78701
Attention: Mike Bengtson
Tel: (512) 322-2661

Fax: (512) 322-8349

If to Operations, addressed to:

Tallgrass Operations, LLC
c/o Tallgrass Development, LP
4200 W. 115th Street, Suite 350
Leawood, KS 66211
Attention: General Counsel
Tel: (913) 928-6010
Fax: (913) 928-6011

with copies (which shall not constitute notice) to:

Baker Botts L.L.P.
98 San Jacinto Blvd., Suite 1500
Austin, Texas 78701
Attention: Mike Bengtson
Tel: (512) 322-2661
Fax: (512) 322-8349

If to the Partnership, addressed to:

Tallgrass Energy Partners, LP
4200 W. 115th Street, Suite 350
Leawood, KS 66211
Attention: General Counsel
Tel: (913) 928-6010
Fax: (913) 928-6011

with copies (which shall not constitute notice) to:

Tallgrass Energy Partners, LP
4200 W. 115th Street, Suite 350
Leawood, KS 66211
Attention: Conflicts Committee Chair
Tel: (913) 928-6010
Fax: (913) 928-6011

Bracewell & Giuliani LLP
711 Louisiana, Suite 2300
Houston, Texas 77002
Attention: Gary W. Orloff
Tel: (713) 221-1306
Fax: (713) 221-2166

Notice given by personal delivery or courier service shall be effective upon actual receipt. Notice given by fax shall be confirmed by appropriate answer back and shall be effective upon actual receipt if received during the recipient's normal business hours, or at the beginning of the recipient's next business day after receipt if not received during the recipient's normal business hours. Any party may change any address to which Notice is to be given to it by giving Notice as provided above of such change of address.

Section 6.5 Governing Law.

(a) This Agreement shall be subject to and governed by the laws of the State of Delaware. Each Party hereby submits to the exclusive jurisdiction of the state and federal courts in the State of Kansas and to venue in the state courts in Johnson County, Kansas and in the federal courts of Wyandotte County, Kansas.

(b) Each of the parties to this Agreement irrevocably waives any and all right to trial by jury in any legal proceeding between the parties arising out of or relating to this Agreement or the transactions contemplated by this Agreement.

(c) Each party to this Agreement waives, to the fullest extent permitted by Applicable Law, any right it may have to receive damages from any other party based on any theory of liability for any special, indirect, consequential (including lost profits), exemplary or punitive damages (except to the extent that any such damages are included in indemnifiable losses resulting from a third party claim in accordance with Article V).

Section 6.6 Public Statements.

The parties hereto shall consult with each other and no party shall issue any public announcement or statement with respect to this Agreement or the transactions contemplated hereby without the consent of the other party, unless the party desiring to make such announcement or statement, after seeking such consent from the other parties, obtains advice from legal counsel that a public announcement or statement is required by Applicable Law or stock exchange regulations.

Section 6.7 Entire Agreement; Amendments and Waivers.

(a) This Agreement and the Assignment Agreement constitute the entire agreement among the parties with respect to the subject matter hereof and supersede all prior agreements and understandings, both written and oral, among the parties with respect to the subject matter hereof. Each party to this Agreement agrees that no other party to this Agreement (including its agents and representatives) has made any representation, warranty, covenant or agreement to or with such party relating to this Agreement or the transactions contemplated hereby, other than those expressly set forth herein and in the Assignment Agreement.

(b) No supplement, modification or waiver of this Agreement shall be binding unless executed in writing by each party to be bound thereby. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision hereof (regardless of whether similar), nor shall any such waiver constitute a continuing waiver unless otherwise expressly provided.

Section 6.8 Conflicting Provisions.

This Agreement and the Assignment Agreement, read as a whole, set forth the parties' rights, responsibilities and liabilities with respect to the transactions contemplated by this Agreement. In this Agreement and the Assignment Agreement, and as between them, specific provisions prevail over general provisions. In the event of a conflict between this Agreement and the Assignment Agreement, this Agreement shall control.

Section 6.9 Binding Effect and Assignment.

This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective permitted successors and assigns, but neither this Agreement nor any of the rights, benefits or obligations hereunder shall be assigned or transferred, by operation of law or otherwise, by any party hereto without the prior written consent of each other party. Nothing in this Agreement, express or implied, is intended to confer upon any person or entity other than the parties hereto and their respective permitted successors and assigns, any rights, benefits or obligations hereunder, except for express language with respect to the Partnership Indemnified Parties and the Development Indemnified Parties contained in the indemnification provisions of Article VI.

Section 6.10 Severability.

If any provision of the Agreement is rendered or declared illegal or unenforceable by reason of any existing or subsequently enacted legislation or by decree of a court of last resort, the Partnership, Development and Operations shall promptly meet and negotiate substitute provisions for those rendered or declared illegal or unenforceable, but all of the remaining provisions of this Agreement shall remain in full force and effect.

Section 6.11 Interpretation.

It is expressly agreed by the parties that neither this Agreement nor the Assignment Agreement shall be construed against any party, and no consideration shall be given or presumption made, on the basis of who drafted this Agreement, the Assignment Agreement or any provision hereof or thereof or who supplied the form of this Agreement or the Assignment Agreement. Each party agrees that this Agreement has been purposefully drawn and correctly reflects its understanding of the transactions contemplated by this Agreement and, therefore, waives the application of any law, regulation, holding or rule of construction providing that ambiguities in an agreement or other document will be construed against the party drafting such agreement or document.

Section 6.12 Headings and Disclosure Schedule.

The headings of the several Articles and Sections herein are inserted for convenience of reference only and are not intended to be a part of or to affect the meaning or interpretation of this Agreement. The Disclosure Schedule and the Exhibits referred to herein are attached hereto and incorporated herein by this reference, and unless the context expressly requires otherwise, the Disclosure Schedule and such Exhibits are incorporated in the definition of "Agreement."

Section 6.13 Multiple Counterparts.

This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

Section 6.14 Action by the Partnership.

With respect to any action, notice, consent, approval or waiver that is required to be taken or given or that may be taken or given by the Partnership with respect to the transactions contemplated hereby, such action, notice, consent, approval or waiver shall be taken or given by the Conflicts Committee on behalf of the Partnership.

* * * * *

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date first written above.

OPERATIONS:

TALLGRASS OPERATIONS, LLC

By: /s/ David G. Dehaemers, Jr.
David G. Dehaemers, Jr.
President and Chief Executive Officer

THE PARTNERSHIP:

TALLGRASS ENERGY PARTNERS, LP
By: Tallgrass MLP GP, LLC,
its general partner

By: /s/ David G. Dehaemers, Jr.
David G. Dehaemers, Jr.
President and Chief Executive Officer

Executed by Tallgrass Development, LP,
solely for purposes of its obligations and rights under
Article III, Article VI and Article VII of this Agreement

DEVELOPMENT:

TALLGRASS DEVELOPMENT, LP

By: Tallgrass Energy Holdings, LLC,
its general partner

By: /s/ David G. Dehaemers, Jr.
David G. Dehaemers, Jr.
President and Chief Executive Officer

DISCLOSURE SCHEDULES

These Disclosure Schedules are provided in connection with that certain Contribution and Transfer Agreement, effective for tax purposes as of January 4, 2016 and effective for all other purposes as of January 1, 2016, (the "Agreement"), by and among Tallgrass Operations, LLC, a Delaware limited liability company ("Operations"), Tallgrass Energy Partners, LP, a Delaware limited partnership (the "Partnership"), and, for certain limited purposes, Tallgrass Development, LP, a Delaware limited partnership ("Development"). Capitalized terms used but not defined herein shall have the respective meanings set forth in the Agreement.

The information disclosed in these Disclosure Schedules is intended to qualify the representations and warranties contained in the Agreement and shall not be deemed to expand in any way the scope or effect of any of such representations and warranties on the part of Operations and Development. Nothing in these Disclosure Schedules constitutes an admission of any liability or obligation of Operations or Development to any third person, or an admission to any third person against the interest of Operations or Development. Descriptions or references of particular contracts, agreements, notices or similar documents herein are qualified in their entirety by reference to such documents. The disclosure of any item or information in these Disclosure Schedules shall not be construed as an admission that such item or information is material to Operations or Development, and any inclusion in these Disclosure Schedules shall not be used in any dispute or controversy between the parties to the Agreement to determine whether any obligation, item or matter (whether or not included in these Disclosure Schedules or described in the Agreement) is or is not material for purposes of the Agreement. In disclosing the information in these Disclosure Schedules, Operations and Development do not waive any attorney-client privilege associated with any such information or any protection afforded by the "work product doctrine" with respect to any of the matters disclosed or discussed herein.

The headings contained in these Disclosure Schedules are for convenience of reference only and shall not be deemed to modify or affect the interpretation of the information contained in these Disclosure Schedules.

* * *

Schedule 3.3

Consents

None.

Schedule 3.5

Litigation

None.

Schedule 3.9

Management Projections

The financial projections delivered by Kelvin Sun via e-mail on October 28, 2015, to Robert Pacha and Alex Jeffries of Evercore Group L.L.C.

Exhibit A

Form of Assignment Agreement

ASSIGNMENT AGREEMENT

This ASSIGNMENT AGREEMENT (this "**Assignment**"), dated as of January 1, 2016, is entered into by and among Tallgrass Operations, LLC, a Delaware limited liability company ("**Assignor**"), Tallgrass Energy Partners, LP, a Delaware limited partnership (the "**Partnership**") and Tallgrass PXP Holdings, LLC, a Delaware limited liability company ("**Assignee**"). Assignor, the Partnership, and Assignee may be referred to individually as a "**Party**" or collectively as the "**Parties**."

RECITALS

A. Pursuant to the terms of a Contribution and Transfer Agreement (the "**Contribution Agreement**", with capitalized terms used but not defined herein having the respective meanings set forth in the Contribution Agreement), dated as of the date hereof, among Assignor, the Partnership, and Tallgrass Development, LP, a Delaware limited partnership, Assignor will transfer to Assignee (a wholly-owned subsidiary of the Partnership) 5,640,000 common units (the "**Subject Interest**") in Tallgrass Pony Express Pipeline, LLC, a Delaware limited liability company (the "**Company**"), comprising 31.3% of the issued and outstanding membership interests in the Company.

NOW THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

AGREEMENT

1.1. Assignment of the Subject Interest. Assignor hereby grants, contributes, bargains, conveys, assigns, transfers, sets over and delivers the Subject Interest to Assignee, and Assignee hereby accepts the Subject Interest.

1.2. Contribution Agreement. This Assignment is subject to, in all respects, the terms and conditions of the Contribution Agreement, and nothing contained herein is meant to enlarge, diminish or otherwise alter the terms and conditions of the Contribution Agreement or the Parties' duties and obligations contained therein. To the extent there is a conflict between this Assignment and the Contribution Agreement, the terms of the Contribution Agreement will control, provided, however, that the Parties acknowledge that the Partnership has directed that Assignee receive the Subject Interest.

1.3. Binding Effect. This Assignment shall be binding upon and inure to the benefit of the Parties and their respective heirs, successors and assigns.

1.4. Governing Law. This Assignment and the transactions contemplated hereby will be governed by and interpreted in accordance with the laws of the State of Delaware, without regard to principles of conflicts of laws.

1.5. Further Assurances. The Parties agree to execute all instruments and to take all actions that are reasonably necessary to effect the transactions contemplated hereby.

1.6. Counterparts. This Assignment may be signed in any number of counterparts, each of which will be an original, with the same effect as if the signatures thereto and hereto were upon the same instrument.

IN WITNESS WHEREOF, the Parties have executed this Assignment as of the date first written above.

ASSIGNOR:

TALLGRASS OPERATIONS, LLC

By:
David G. Dehaemers, Jr.
President and Chief Executive Officer

PARTNERSHIP:

TALLGRASS ENERGY PARTNERS, LP
By: Tallgrass MLP GP, LLC, its general partner

By:
David G. Dehaemers, Jr.
President and Chief Executive Officer

ASSIGNEE:

TALLGRASS PXP HOLDINGS, LLC

By:
David G. Dehaemers, Jr.
Chief Executive Officer

Exhibit B

Form of Statement to Tallgrass Energy Partners, LP of Qualifying Capital Expenditures

Reference is made to that certain Contribution and Transfer Agreement made and effective for tax purposes as of January 4, 2016, and effective for all other purposes as of January 1, 2016, by and among Tallgrass Energy Partners, LP, Tallgrass Operations, LLC ("**Operations**") and Tallgrass Pony Express Pipeline, LLC (the "**Agreement**"). Tallgrass Development, LP, a Delaware limited partnership, is also a party to the Agreement for certain limited purposes. Capitalized terms not otherwise defined herein have the meanings set forth in the Agreement.

Pursuant to Section 2.6(b) of the Agreement, the Cash Amount shall be treated as a reimbursement of Operations' capital expenditures within the meaning of Treasury Regulation Section 1.707-4(d) to the extent of the qualifying capital expenditures set forth herein.

The amount of qualifying capital expenditures is $**[Insert amount of qualifying capital expenditures.]**.

The basis for the qualification of the qualifying capital expenditures is as follows: **[Describe basis for qualification.]**

Evidence documenting the capital expenditures and their qualification is attached hereto.

Dated: ____________________________ ____________

Name:

Title:
of Tallgrass Operations, LLC

Appendix A

The Partnership, Development and Operations Designated Personnel

Development and Operations Designated Personnel:

- David G. Dehaemers, Jr.
- William R. Moler
- George E. Rider
- Gary J. Brauchle
- Richard L. Bullock
- Christopher R. Jones

Partnership Designated Personnel:

- David G. Dehaemers, Jr.
- William R. Moler
- George E. Rider
- Gary J. Brauchle
- Richard L. Bullock
- Christopher R. Jones

Exhibit 12.1

RATIO OF EARNINGS TO FIXED CHARGES
(in thousands, except ratio data)

The table below sets forth the calculation of Ratios of Earnings to Fixed Charges for the periods indicated.

	TEP [1]				TEP Pre-Predecessor	
	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from November 12, 2012 to December 31, 2012	Period from January 1, 2012 to November 12, 2012	Year Ended December 31, 2011
Earnings from continuing operations before fixed charges:						
Pre-tax income from continuing operations before earnings from unconsolidated affiliates [2]	$ 184,814	$ 58,612	$ 7,624	$ (2,618)	$ 51,775	$ 77,803
Fixed charges	25,437	11,626	13,360	3,450	69	83
Amortization of capitalized interest	66	35	—	—	—	—
Distributed earnings from unconsolidated affiliates	—	717	—	—	—	—
less: Capitalized interest	(811)	(1,025)	(242)	—	—	—
Earnings from continuing operations before fixed charges	$ 209,506	$ 69,965	$ 20,742	$ 832	$ 51,844	$ 77,886
Fixed charges:						
Interest expense, net of capitalized interest	14,226	7,648	11,264	3,040	—	—
Capitalized interest	811	1,025	242	—	—	—
Estimate of interest within rental expense (33.3%)	8,615	1,574	109	14	69	83
Amortization of debt costs	1,785	1,379	1,745	396	—	—
Total fixed charges	$ 25,437	$ 11,626	$ 13,360	$ 3,450	$ 69	$ 83
Ratio of earnings to fixed charges	8.24	6.02	1.55	— [3]	751.36	938.39

(1) TEP closed the acquisition of Trailblazer on April 1, 2014 and the acquisition of a controlling 33.3% membership interest in Pony Express effective September 1, 2014. As the acquisitions of Trailblazer and the initial 33.3% of Pony Express were considered transactions between entities under common control, and changes in reporting entity, financial information presented subsequent to November 13, 2012 and prior to the respective acquisition dates has been recast to include Trailblazer and the initial 33.3% of Pony Express. TEP closed the acquisition of an additional 33.3% membership interest in Pony Express effective March 1, 2015, which represents a transaction between entities under common control and an acquisition of noncontrolling interests. As a result, financial information for periods prior to March 1, 2015 have not been recast to reflect the additional 33.3% membership interest.

(2) For purposes of determining the ratio of earnings to fixed charges, earnings are defined as pretax income or loss from continuing operations before earnings from unconsolidated affiliates, plus fixed charges, plus distributed earnings from unconsolidated affiliates, less capitalized interest. Fixed charges consist of interest expensed, capitalized interest, amortization of deferred loan costs, and an estimate of the interest within rental expense.

(3) As a result of the net loss for the period from November 12, 2012 to December 31, 2012, the ratio of earnings to fixed charges was less than 1:1. TEP would have needed to generate additional earnings of $2.6 million to achieve an earnings to fixed charges ratio of 1:1 for the period from November 12, 2012 to December 31, 2012.

Exhibit 21.1

Tallgrass Energy Partners, LP
Subsidiaries

Company	Jurisdiction of Organization
Tallgrass MLP Operations, LLC	Delaware
Tallgrass Energy Finance Corp.	Delaware
Tallgrass Interstate Gas Transmission, LLC	Colorado
Tallgrass Midstream, LLC	Delaware
Tallgrass Energy Investments, LLC	Delaware
Trailblazer Pipeline Company LLC	Delaware
Tallgrass PXP Holdings, LLC	Delaware
Tallgrass Pony Express Pipeline, LLC	Delaware
Tallgrass Colorado Pipeline, Inc.	Colorado
BNN Water Solutions, LLC	Delaware
BNN Redtail, LLC	Delaware
Alpha Reclaim Technology, LLC	Texas
BNN Western, LLC	Delaware
BNN South Texas, LLC	Delaware
BNN West Texas, LLC	Delaware
BNN Recycle, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S‑3 (No. 333-196454), Form S-3 (No. 333-205781) and S‑8 (No. 333-189417) of Tallgrass Energy Partners, LP of our report dated February 17, 2016 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10‑K.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 17, 2016

Exhibit 31.1

Certification by Chief Executive Officer pursuant to
Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934,
as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, David G. Dehaemers, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K of Tallgrass Energy Partners, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ David G. Dehaemers, Jr.

David G. Dehaemers, Jr.

President and Chief Executive Officer of Tallgrass MLP GP, LLC (the general partner of Tallgrass Energy Partners, LP)

Date: February 17, 2016

Exhibit 31.2

Certification by Chief Financial Officer pursuant to
Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934,
as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Gary J. Brauchle, certify that:

1. I have reviewed this Annual Report on Form 10-K of Tallgrass Energy Partners, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ Gary J. Brauchle

Gary J. Brauchle

Executive Vice President and Chief Financial Officer of
Tallgrass MLP GP, LLC (the general partner of
Tallgrass Energy Partners, LP)

Date: February 17, 2016

Exhibit 32.1

Certification Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Tallgrass Energy Partners, LP (the "Partnership") on Form 10-K for the year ended December 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David G. Dehaemers, Jr., President and Chief Executive Officer of Tallgrass MLP GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 ("Section 906"), that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ David G. Dehaemers, Jr.

David G. Dehaemers, Jr.

President and Chief Executive Officer of Tallgrass MLP GP, LLC (the general partner of Tallgrass Energy Partners, LP)

Date: February 17, 2016

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certification Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Tallgrass Energy Partners, LP (the “Partnership”) on Form 10-K for the year ended December 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Gary J. Brauchle, Executive Vice President and Chief Financial Officer of Tallgrass MLP GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (“Section 906”), that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/Gary J. Brauchle

Gary J. Brauchle

Executive Vice President and Chief Financial Officer of Tallgrass MLP GP, LLC (the general partner of Tallgrass Energy Partners, LP)

Date: February 17, 2016

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained and furnished to the Securities and Exchange Commission or its staff upon request.

CORPORATE INFORMATION

BOARD OF DIRECTORS

David G. Dehaemers, Jr.
William R. Moler
Jeffrey R. Armstrong
Jeffrey A. Ball
Roy N. Cook
Frank J. Loverro
Stanley de J. Osborne
John T. Raymond
Terrance D. Towner

EXECUTIVE MANAGEMENT

David G. Dehaemers, Jr.
President and Chief Executive Officer

W. R. (Bill) Moler
Executive Vice President &
Chief Operating Officer

Gary J. Brauchle
Executive Vice President &
Chief Financial Officer

George E. Rider
Executive Vice President,
General Counsel & Secretary

PUBLIC HEADQUARTERS

4200 W. 115th Street
Suite 350
Leawood, KS 66211
(913) 928-6012

TALLGRASS ENERGY

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Suite 350
Leawood, KS 66211
(913) 928-6012

370 Van Gordon Street
Lakewood, CO 80228
(303) 763-2950

INVESTOR RELATIONS

(913) 928-6012
investor.relations@tallgrassenergylp.com

MEDIA RELATIONS

(913) 928-6014
media.relations@tallgrassenergylp.com

TRANSFER AGENT

American Stock Transfer and Trust

TICKER SYMBOL

NYSE:TEP

TALLGRASS ENERGY PARTNERS, LP 2015 ANNUAL REPORT

TALLGRASS
ENERGY PARTNERS

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