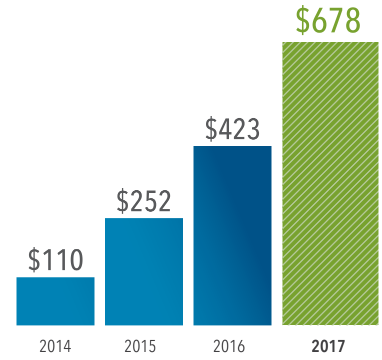
TALLGRASS ENERGY PARTNERS

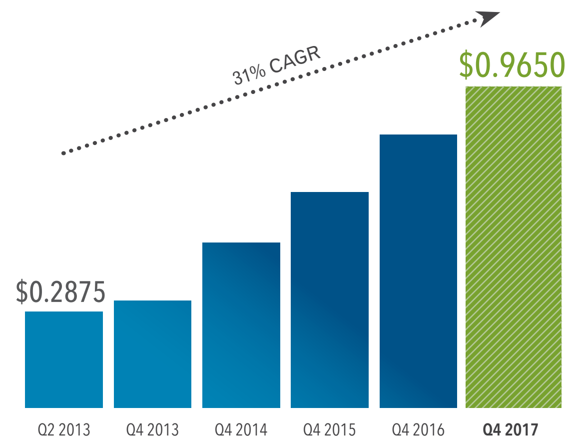
TALLGRASS ENERGY PARTNERS 2017 ANNUAL REPORT

ABOUT TALLGRASS
Energy Partners, LP

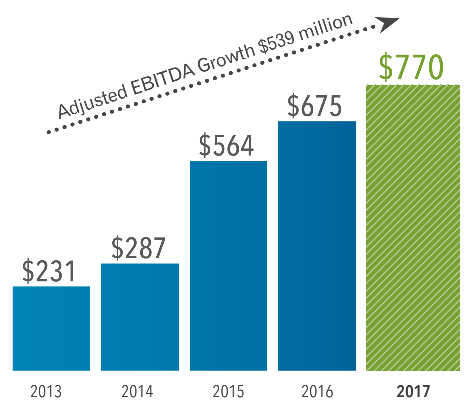
Tallgrass Energy Partners, LP (NYSE: TEP) is a publicly traded, growth-oriented limited partnership formed to own, operate, acquire and develop midstream energy assets in North America. TEP provides natural gas transportation and storage services for customers in the Rocky Mountain, Midwest and Appalachian regions of the United States through: (1) its 49.99 percent membership interest in Rockies Express Pipeline LLC, which owns the Rockies Express Pipeline, a FERC-regulated natural gas pipeline system extending from Opal, Wyo., and Meeker, Colo., to Clarington, Ohio, and its 100 percent membership interest in Tallgrass NatGas Operator, LLC, which operates the Rockies Express Pipeline, (2) the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system located in Colorado, Kansas, Missouri, Nebraska and Wyoming, and (3) the Trailblazer Pipeline system, a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Neb. TEP currently provides crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through Tallgrass Pony Express Pipeline, LLC, which owns a FERC-regulated crude oil pipeline commencing in Guernsey, Wyo., and terminating in Cushing, Okla., and includes a lateral in Northeast Colorado commencing in Weld County, Colo., that interconnects with the pipeline just east of Sterling, Colo. TEP provides natural gas gathering and processing services for customers in Wyoming through: (1) a natural gas gathering system in the Powder River Basin (2) the Casper and Douglas natural gas processing facilities, and (3) the West Frenchie Draw natural gas treating facility. TEP also provides crude oil gathering services for customers in Wyoming through a crude oil gathering system in the Powder River Basin; and NGL transportation services in Northeast Colorado and Wyoming. TEP owns water infrastructure, including freshwater transportation and produced water gathering and disposal, in Colorado, Texas, Wyoming and North Dakota through BNN Water Solutions, LLC, and crude oil storage and terminalling services through Tallgrass Terminals, LLC, which owns and operates crude oil terminals near Sterling, Colo., and in Weld County, Colo. Terminals also owns an approximate 60 percent membership interest in Deeprock Development, LLC, which owns a crude oil terminal in Cushing, Okla.



TEP Adjusted EBITDA
(in millions)



TEP Distributions
per Unit



Tallgrass Energy Adjusted EBITDA*
(in millions)

Invested Capital**		Adjusted EBITDA Growth		Multiple on Invested Capital
$3.1 Billion	÷	**$539 Million**	=	**5.8x**

**Represents Adjusted EBITDA across the Tallgrass Energy Family of Companies. A reconciliation of this non-GAAP metric is available under the Webcasts & Presentations section at www.tallgrassenergy.com.*

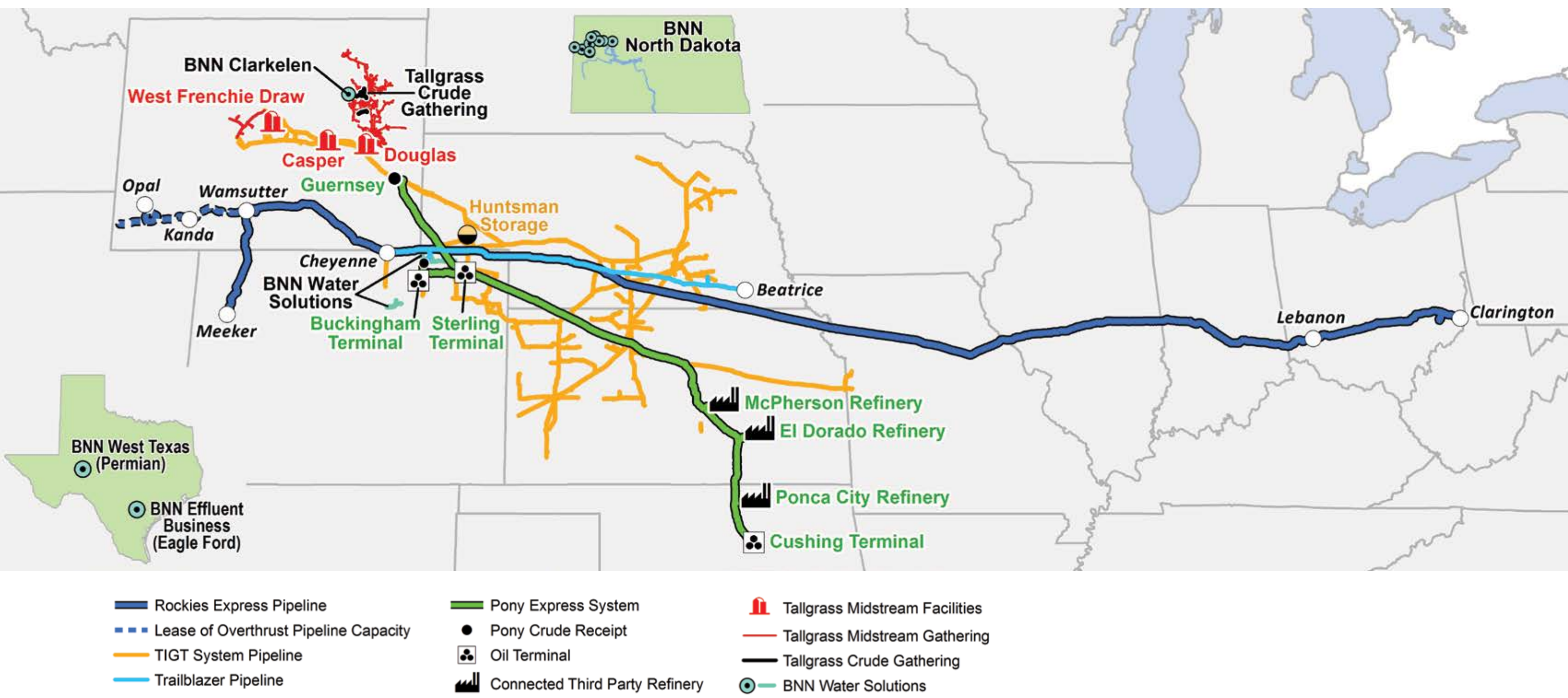
***Invested capital for 2013–2017 includes cash invested by TEP and Tallgrass Development for growth projects and third-party acquisitions, inclusive of capital contributions made to REX for debt repayment and growth projects.*

336%

DISTRIBUTION INCREASE

336% DPU increase since IPO.

TALLGRASS SYSTEM MAP



Letter to TEP Unitholders

CELEBRATING FIVE YEARS OF STRATEGIC GROWTH AND FINANCIAL STRENGTH

As I reflect on 2017, I take a great deal of pride in the exceptional team we have at Tallgrass. I'm thankful every day for the opportunity to lead such an extraordinary group of people and for what they do day in and day out—safely operate our assets and find innovative ways to add value to our unitholders, customers and each other. It's no surprise to me that our employees delivered another stellar year, enabled us to do what we said we would do and continued our path of growth and financial stability in 2017.

In 2017, Tallgrass celebrated our fifth anniversary. On Nov. 13, 2012, we closed on the transaction that created Tallgrass Energy. Six months later, we took TEP public. Our five-year milestone provided an opportunity for us to look back over the last five years and celebrate how far we've come since our inception. We hope those of you who have followed us throughout our journey share our sense of accomplishment and optimism for the future. With that as a backdrop, let's take a look at highlights from 2017.

CONTINUED EXECUTION IN 2017

Tallgrass steadfastly stuck to our business strategy, even as the industry continued its slow and steady path to recovery last year, demonstrating our ability to deliver strong results in the face of both favorable and unfavorable market conditions. In many respects, 2017 was like years past in that we continued to increase distributions and deliver the exceptional value our unitholders expect from us. Building on our track record, Q4 2017 marked the 18th consecutive quarterly distribution increase since TEP's May 2013 IPO.

We expected to cover our distributions in 2017 by about 1.4 times and generate almost $175 million in excess of anticipated distributions, all while still growing distributions at about 20 percent. We did that, covering our distributions by nearly 1.5 times, generating cash of approximately $200 million in excess of our distributions, and growing distributions by 18.4 percent. In addition, we delivered at the high end of our 2017 guidance with Adjusted EBITDA of approximately $678 million and Distributable Cash Flow of approximately $611 million.

In 2017, we continued to demonstrate our ability to grow organically and through strategic third-party acquisitions, as well as through drop-downs. Our assets are in or near some of the nation's most prolific oil and gas basins, and we continue to build our footprint in those geographic areas. In 2017, we successfully executed approximately $250 million of third-party acquisitions and approximately $136 million of organic growth projects.

Our business model is working for us—and by extension for our investors—so we're going to keep doing what we do. Our track record shows we're on the right path, and we look forward to being evaluated on our performance—not what others in our space are doing or have done.

Now, for some asset-specific accomplishments from 2017.

2017—A YEAR OF STRATEGIC GROWTH VIA ACQUISITIONS AND ORGANIC EXPANSION

Drop-Down Acquisitions

In 2017, we continued to execute our drop-down strategy. TEP acquired Tallgrass Terminals, LLC and Tallgrass NatGas Operator, LLC from Tallgrass Development in January for $140 million and later in the year acquired an additional nearly 25 percent of REX from Tallgrass Development for $400 million, bringing TEP's ownership interest in REX to approximately 50 percent.

Cheyenne Connector

We announced the joint development of the Cheyenne Connector pipeline with Western Gas Partners, LP and DCP Midstream, LP to connect DJ Basin natural gas supply with the Rockies Express Pipeline Cheyenne Hub just south of the Colorado-Wyoming border. In conjunction with the REX Cheyenne Hub Enhancement project, Cheyenne Connector will be instrumental in giving greater market access to DJ natural gas producers.

Rockies Express Pipeline (REX)

- Announced the Cheyenne Hub Enhancement, which in connection with Tallgrass' separate Cheyenne Connector project serves three strategic purposes: 1) continues the transformation of REX into North America's premier northernmost natural gas header system; 2) increases the volumes coming into REX in the long

TALLGRASS ENERGY

Key Accomplishments

PROJECT | 3RD-PARTY ACQUISITION | DROP-DOWN ACQUISITION

2013

- TMID Casper Expansion
- TMID Douglas Expansion
- TIGT West End Expansion
- Contract Trailblazer's Redtail Lateral
- Pony Northeast Colorado Lateral Open Season
- Contract REX's Seneca Lateral
- 20% Interest in Cushing Terminal Acquisition

2014

- Pony Placed into Service
- REX Signs Capacity Enhancement PAs
- REX Signs E2W PAs
- Sterling Terminal Constructed
- BNN Water Business Acquisition
- 33.3% Pony Acquisition
- Trailblazer Acquisition

2015

- Pony Expansion Project Placed into Service
- Seneca Lateral Achieves Full Capacity
- REX Zone 3 E2W Project Placed into Service
- TMID Redtail NGL Pipeline Placed into Service
- Whiting Water Business Acquisition
- 33.3% Pony Acquisition

term; and 3) provides DJ producers an outlet to additional markets. Once at the Hub, producers' gas can be transported east or west on REX, accessing any number of interconnecting pipelines to reach West, Midwest, Southeast or Gulf Coast markets.

- Optimized the REX Zone 3 Capacity Enhancement Project by up to 400 MMcf/d, generating millions of dollars in revenue from the sale of that incremental capacity.
- Secured additional demand-pull volumes on REX by connecting two new power plants and signed precedent agreements with a third power plant in Ohio and a superalloy facility in Nebraska.
- Set a record daily peak flow on REX of approximately 4.7 Bcf.

Pony Express and Crude Oil Gathering

- Acquired an oil gathering system in the Powder River Basin and announced plans to directly connect the system to the Pony Express Pipeline, furthering our strategy of becoming a comprehensive midstream service provider in the Powder and advancing Pony's position as the most attractive, diverse and capable crude oil transportation and logistics system in the regions in which it operates.
- Added new delivery points, connecting two new refineries that were placed into service in January 2018.
- Restructured Pony's contract with its largest customer, extending it through October 2024—five years beyond its original expiration date of October 2019.
- Began construction on two new receipt points at Platteville and Natoma which are expected to be in service in 2018. With these new receipt points, Pony Express will add two new common streams of crude oil for a total of five common streams.

Terminals

- Raised our ownership interest in the Deeprock Development crude oil terminal at Cushing, Okla., to 69 percent, and acquired a 38 percent interest in Deeprock North, LLC. Deeprock North was subsequently merged into Deeprock Development, and Tallgrass Terminals now owns more than 60 percent of the combined entity with 4 million barrels of storage capacity and retains significant strategic and commercial control allowing for future optionality.
- Signed a 10-year take-or-pay agreement to support the construction of a terminal in the Central Kansas Uplift at Natoma.
- Announced an agreement to acquire a 51 percent interest in the Pawnee Terminal, which is expected to close in the first quarter of 2018. This acquisition will provide commercial and operational synergies with Pony Express and offers the potential for incremental sourcing opportunities such as directly connecting nearby producers.

Gathering, Processing and Water Businesses

- In addition to the oil gathering system mentioned earlier, we also acquired a natural gas gathering system in the Powder River Basin that will help us optimize and grow the Douglas Processing Plant.
- Increased gathering and processing volumes over 2016.
- Our water business expanded into the Powder River Basin through acquisition and greenfield development. We also organically expanded our water supply, gathering, and disposal operations in the DJ and Permian basins throughout the year.

TIGT and Trailblazer

- Tallgrass Interstate Gas Transmission extended contracts with key customers, including one through October 2023 and another through March 2024.
- Trailblazer Pipeline added an interconnect to Fortigen Geneva's anhydrous ammonia plant in Geneva, Neb., which will come online in early 2018.

LOOKING AHEAD TO 2018

As we enter a new year, we believe the industry is showing signs of a sustainable recovery. We entered January 2018 with WTI crude above $60 for the first time since 2014, and we're hopeful that the volatility of the last couple of years is behind us. Our customers are more confident in the coming year, and we're looking forward to building on the foundation we laid over the last five years.

At the end of 2017, we had approximately $1.1 billion of liquidity available on our revolver and a leverage ratio of approximately 3.0 times, leaving ample dry powder for additional acquisitions, organic growth and drop-down acquisitions down the road.

As I've said before, we manage our business for the long term and we know that as long as we keep our eye out over the horizon and stay true to our strategic plan we will continue to meet or exceed our objectives and your—our partners'—high expectations.

I'd like to end this letter with where I started, and that's with another resounding "thank you" to all the extraordinary people on the Tallgrass team who make our continued success possible. In addition, I thank our unitholders, our customers, our suppliers and all our other supporters who make this all worthwhile.

Sincerely,

David G. Dehaemers Jr.
President and Chief Executive Officer

2016

- Buckingham Terminal Constructed
- REX Capacity Enhancement Project Fully Contracted

- 25.0% REX Acquisition from Sempra

- 31.3% Pony Acquisition

2017

- REX Capacity Enhancement Placed into Service
- Successful Platteville Extension Open Season
- Announced New Pony Refinery & Supply Connections
- North Sterling Water Pipeline Placed into Service
- Successful Open Seasons for Cheyenne Connector & Cheyenne Hub

- PRB Oil Gathering System Acquisition
- PRB & DJ Water Asset Acquisitions
- PRB Gas Gathering System Acquisition
- Acquired Additional 49% Interest in Deeprock Development

- 24.99% REX Acquisition
- Terminals and NatGas Operator Acquisition

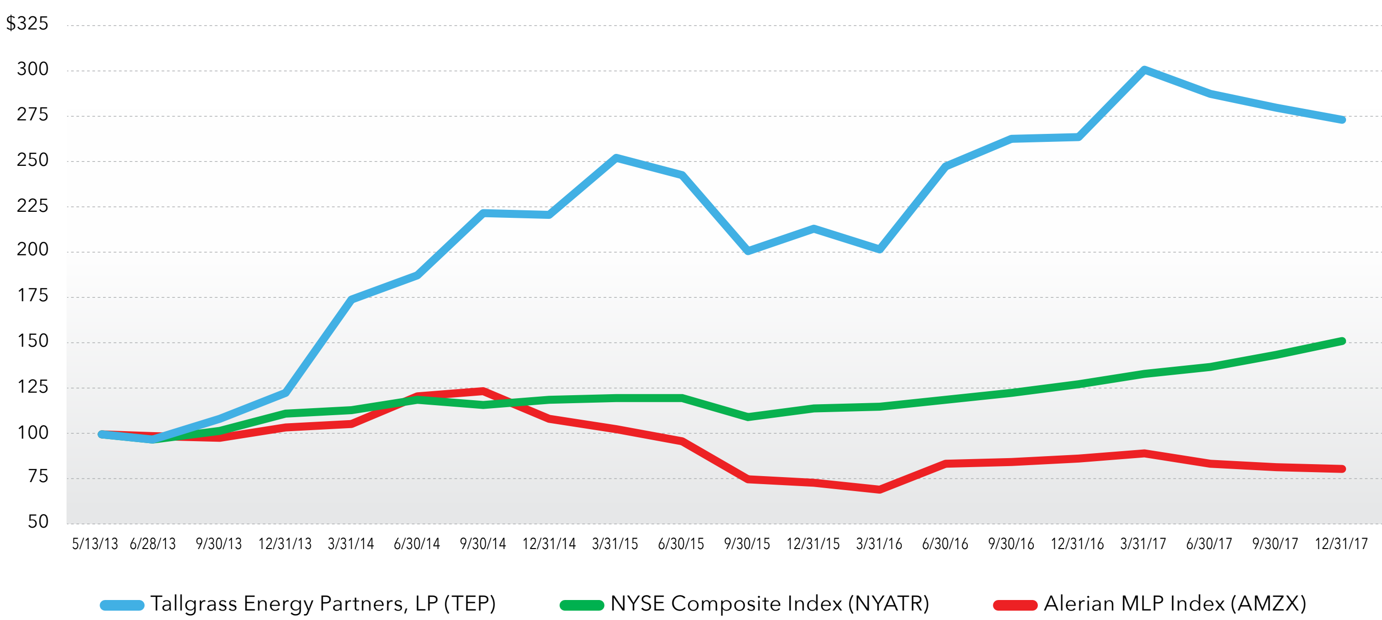
Summary Financial Information

(in thousands, except coverage and per unit data)	**2017**	2016[(1)]	2015[(1)]	2014[(1)]
Net income attributable to partners	**$ 433,990**	$ 263,529	$ 160,546	$ 70,681
Add:				
Interest expense, net of noncontrolling interest	**83,542**	40,688	15,517	7,648
Depreciation and amortization expense, net of noncontrolling interest	**92,455**	85,971	75,529	45,389
Distributions from unconsolidated investments	**306,626**	75,900	—	1,464
Non-cash compensation expense	**8,660**	5,780	5,103	5,136
(Gain) loss from disposal of assets, net of noncontrolling interest	**(654)**	1,849	4,795	—
Non-cash loss (gain) related to derivative instruments, net of noncontrolling interest	**226**	1,547	—	(184)
Loss on extinguishment of debt	**—**	—	226	—
Less:				
Equity in earnings of unconsolidated investments	**(237,110)**	(51,780)	—	(717)
Gain on remeasurement of unconsolidated investment	**(9,728)**	—	—	(9,388)
Non-cash loss allocated to noncontrolling interest	**—**	—	(9,377)	(10,151)
Adjusted EBITDA	**$ 678,007**	$ 423,484	$ 252,339	$109,878
Add:				
Deficiency payments received, net	**$ 27,182**	$ 33,496	$ 16,511	$ 5,378
Pony Express preferred distributions in excess of distributable cash flow attributable to Pony Express	**—**	—	—	5,429
Less:				
Cash interest cost	**(79,081)**	(37,110)	(13,746)	(6,266)
Maintenance capital expenditures, net	**(14,822)**	(11,323)	(12,123)	(9,913)
Distributions to noncontrolling interest in excess of earnings	**—**	—	(22,479)	(5,361)
Cash flow attributable to predecessor operations	**—**	—	—	(3,086)
Distributable cash flow (DCF)	**611,286**	408,547	220,502	96,059
Less:				
Distributions	**(415,716)**	(321,953)	(192,580)	(83,329)
Amounts in excess of distributions	**$ 195,570**	$ 86,594	$ 27,922	$ 12,730
Distribution coverage	**1.47x**	1.27x	1.14x	1.15x

(1) The financial results exclude the applicable results of operations of Tallgrass Terminals, LLC and Tallgrass NatGas Operator, LLC, which were acquired by TEP effective Jan. 1, 2017.

Total Unitholders Return

Tallgrass Energy Partners, LP



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, 2017
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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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, 2017, the last business day of the Registrant's most recently completed second fiscal quarter (based on the closing sale price of $50.09 of the Registrant's Common Units, as reported by the New York Stock Exchange on such date) was approximately $2,336.2 million. On February 13, 2018, the Registrant had 73,199,753 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 are directly tied 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: an 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: the United States Federal Energy Regulatory Commission.

Firm fee contracts: contracts or other arrangements, including tariff provisions, that 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: accounting principles generally accepted 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 end users 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.

MDth: one thousand dekatherms.

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, 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.

NYSE: New York Stock 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.

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: contracts or other arrangements, including tariff provisions, that 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 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, including the acquisitions discussed in Item 1.—Business, *"Acquisitions;"*
- the demand for our services, including crude oil transportation, storage, gathering and terminalling services; natural gas transportation, storage, gathering and processing services; and water business services, as well as our ability to successfully contract or re-contract with our customers;
- large or multiple customer defaults, including defaults resulting from actual or potential insolvencies;
- our ability to successfully implement our business plan;
- changes in general economic conditions;
- competitive conditions in our industry;
- the effects of existing and future laws and governmental regulations;
- actions taken by third-party operators, processors and transporters;
- 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, natural gas liquids, 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, storing, gathering and terminalling crude oil; transporting, storing, gathering and processing natural gas; and transporting, gathering and disposing of water produced in connection with hydrocarbon exploration and production activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- changes in tax laws, regulations and status;
- 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. Our operations are 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 Marcellus, Utica, Niobrara, Bakken, Mississippi Lime, and Eagle Ford shale formations. We intend to continue to utilize the significant experience of our management team to execute our growth strategy of acquiring midstream assets, increasing utilization of our existing assets and expanding our systems through construction of additional assets.

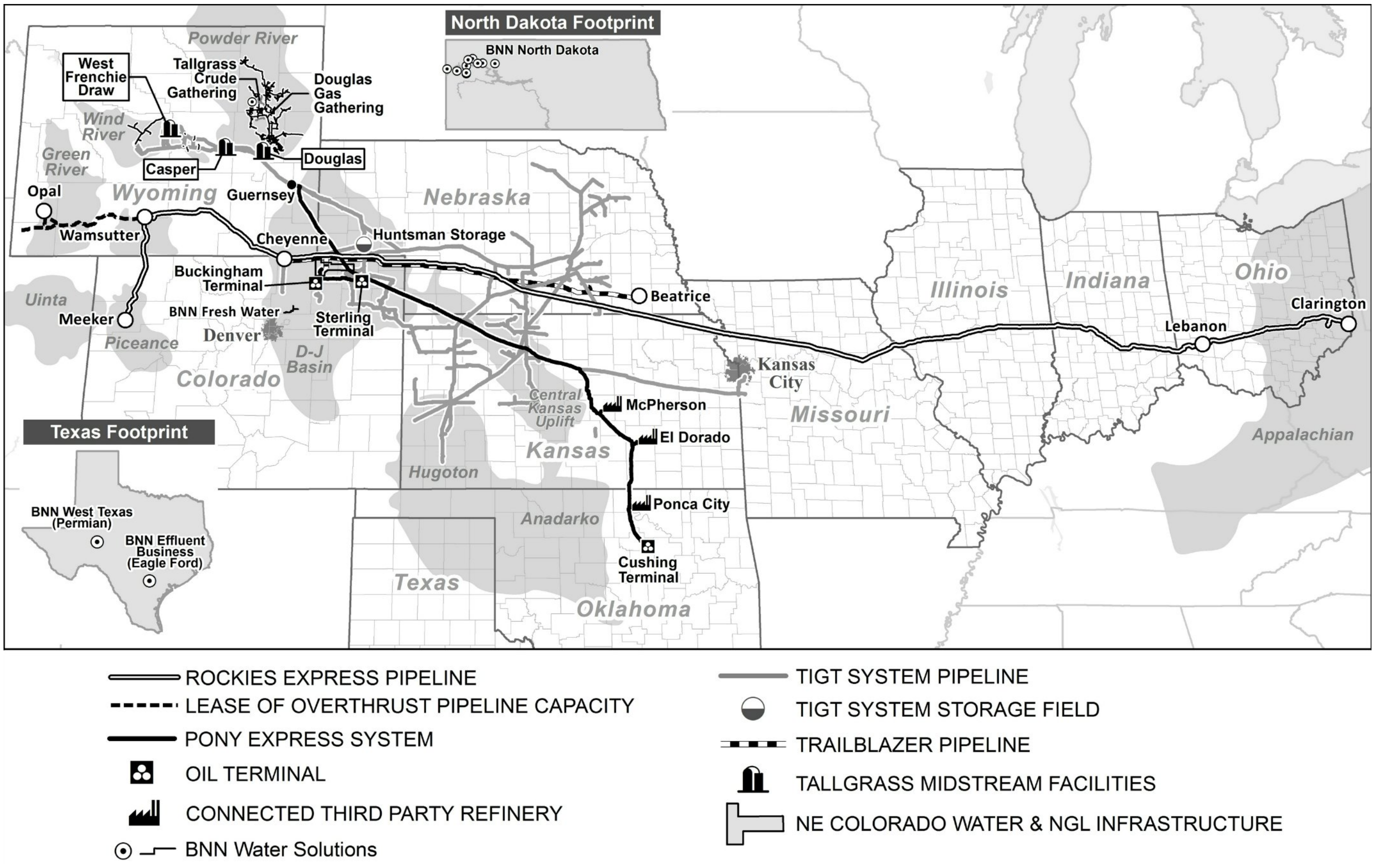
Our reportable business segments are:

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

The following map shows our primary assets, which consist of natural gas transportation, storage, gathering and processing assets, crude oil transportation, storage, gathering, and terminalling assets, and water business services assets. Each of these assets are described in more detail below. Connected third party refineries are also indicated on the map below.



Natural Gas Transportation Segment

Rockies Express Pipeline. We own a 49.99% membership interest in Rockies Express Pipeline LLC ("Rockies Express"), which owns the Rockies Express Pipeline, a FERC-regulated natural gas pipeline system with approximately 1,712 miles of transportation pipelines, including laterals, extending from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio (the "Rockies Express Pipeline") and consists of three zones:

- Zone 1 - 328 miles of mainline pipeline from the Meeker Hub in Northwest Colorado, across Southern Wyoming to the Cheyenne Hub in Weld County, Colorado capable of transporting 2.0 Bcf/d of natural gas from west-to-east;
- Zone 2 - 714 miles of mainline pipeline from the Cheyenne Hub to an interconnect in Audrain County, Missouri capable of transporting 1.8 Bcf/d of natural gas from west-to-east; and
- Zone 3 - 643 miles of mainline pipeline from Audrain County, Missouri to Clarington, Ohio, which is bi-directional and capable of transporting 1.8 Bcf/d of natural gas from west-to-east and 2.6 Bcf/d of natural gas from east-to-west.

For the year ended December 31, 2017, approximately 97% of Rockies Express' revenues were generated under firm fee contracts.

The following tables provide information regarding the Rockies Express Pipeline for the years ended December 31, 2017, 2016, and 2015 and as of December 31, 2017:

	Year Ended December 31,		
	2017	2016	2015
Approximate average daily deliveries (Bcf/d) [(1)]	4.3	3.2	2.5

	Approximate Capacity	Total Firm Contracted Capacity [(2)]	Approximate % of Capacity Subscribed under Firm Contracts	Weighted Average Remaining Firm Contract Life [(3)]
West-to-east	2.0 Bcf/d	1.5 Bcf/d	75%	3 years
East-to-west	2.6 Bcf/d	2.6 Bcf/d	100%	15 years

(1) Reflects average total daily deliveries for the Rockies Express Pipeline, regardless of flow direction or distance traveled.

(2) Reflects total capacity reserved under long-term firm fee contracts as of December 31, 2017. West-to-east firm contracted capacity excludes the 0.2 Bcf/d contracted with Ultra beginning December 1, 2019 as part of the settlement agreement discussed in Note 17 – *Legal and Environmental Matters*.

(3) Weighted by contracted capacity as of December 31, 2017. Weighted average remaining firm contract life of west-to-east contracts excludes the 0.2 Bcf/d contract with Ultra discussed above. After giving effect to the Ultra contract agreement reached in January 2017, the weighted average life of the west-to-east contract lives would be approximately 4 years.

TIGT System. We own a 100% membership interest in Tallgrass Interstate Gas Transmission, LLC ("TIGT"), which owns the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system with approximately 4,641 miles of varying diameter transportation pipelines serving Wyoming, Colorado, Kansas, Missouri and Nebraska (the "TIGT System"). 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, 2017, approximately 93% of the TIGT System's transportation revenue was generated from contracts with on-system customers.

Trailblazer Pipeline. We own a 100% membership interest in Trailblazer Pipeline Company LLC ("Trailblazer"), which owns the Trailblazer Pipeline system, a FERC-regulated natural gas pipeline system with approximately 465 miles of transportation pipelines, including laterals, that begins along the border of Wyoming and Colorado and extends to Beatrice, Nebraska (the "Trailblazer Pipeline"). During the year ended December 31, 2017, substantially all of Trailblazer Pipeline's operationally available long-haul capacity was contracted under firm transportation contracts.

The following tables provide information regarding the TIGT System and Trailblazer Pipeline for the years ended December 31, 2017, 2016, and 2015 and as of December 31, 2017:

	Year Ended December 31,		
	2017	2016	2015
Approximate average daily deliveries (Bcf/d)	1.2	1.1	1.1

	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........	5,106	2.0 Bcf/d	1.7 Bcf/d	83%	4 years
Storage..................	n/a	15.974 Bcf (3)	11 Bcf	69%	4 years

(1) Reflects total capacity reserved under long-term firm fee contracts, including backhaul service, as of December 31, 2017.

(2) Weighted by contracted capacity as of December 31, 2017.

(3) The FERC certificated working gas storage capacity.

NatGas. We own a 100% membership interest in Tallgrass NatGas Operator, LLC ("NatGas"), which is the operator of the Rockies Express Pipeline and receives a fee from Rockies Express as compensation for its services.

Crude Oil Transportation Segment

Pony Express. 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"). As discussed in Note 20 – *Subsequent Events*, TEP acquired the remaining 2% membership interest in Pony Express from Tallgrass Development effective February 1, 2018, bringing our aggregate membership interest in Pony Express to 100%. Pony Express owns an approximately 769-mile crude oil pipeline commencing in Guernsey, Wyoming, and terminating in Cushing, Oklahoma, with delivery points at the McPherson, El Dorado and Ponca City refineries and in Cushing, Oklahoma, and 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"). In addition, Pony Express is currently constructing a 55-mile extension that will extend the Pony Express System beginning at a new origin near Platteville, Colorado and ending at the Buckingham Terminal (together, the “Platteville Extension”). We believe the Pony Express System is positioned as a low-cost, competitive transportation system with access to Bakken Shale, DJ Basin and Powder River Basin production.

The table below sets forth certain information regarding the Pony Express System as of December 31, 2017 and for the periods indicated:

Approximate Design Capacity (bbls/d) (1)	Approximate Contractible Capacity Under Contract (1)(2)	Weighted Average Remaining Firm Contract Life (3)	Approximate Average Daily Throughput (bbls/d) Year Ended December 31, 2017	2016	2015
320,000	100%	3 years	267,734	285,507	236,256 (4)

(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. The weighted average remaining firm contract life reflects the Continental Resources, Inc. ("Continental Resources") contract extension effective January 1, 2018.

(4) Approximate average daily throughput for the three months ended December 31, 2015 was 288,362 bbls/d. Approximate average daily throughput for the year ended December 31, 2015 reflects 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.

Gathering, Processing & Terminalling Segment

Midstream Facilities. We own a 100% membership interest in Tallgrass Midstream, LLC ("TMID"), which owns and operates a natural gas gathering system in the Powder River Basin (the "Douglas Gathering System") that was acquired on June 5, 2017. TMID also owns and operates natural gas processing plants in Casper and Douglas, Wyoming and a natural gas treating facility at West Frenchie Draw, Wyoming (collectively with the Douglas Gathering System, the "Midstream Facilities"). The Casper and Douglas plants currently have combined processing capacity of approximately 190 MMcf/d. The Casper plant also has an 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. TMID also owns and operates an 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, and an NGL pipeline that originates at our Douglas facility and interconnects with ONEOK's Bakken NGL Pipeline. Each of our NGL pipelines are supported by 10-year leases for 100% of their respective pipeline capacity, with the lease for the NGL pipeline in Northeast Colorado having commenced in October 2015, and the lease for the NGL pipeline from our Douglas facility having commenced on January 1, 2017. During the year ended December 31, 2017, approximately 17%, 53%, and 30% of TMID's Adjusted EBITDA came from firm fee, volumetric fee, and commodity sensitive contracts, respectively.

We also provide crude oil gathering services for customers in Wyoming through a 50-mile crude oil gathering system in the Powder River Basin (the "PRB Crude System") acquired on August 3, 2017. As discussed in Note 20 – *Subsequent Events*, we have agreed to sell the PRB Crude System to an affiliate of Silver Creek Midstream, LLC. The sale is expected to close in February 2018.

The table below sets forth certain information regarding natural gas gathering and processing at the Midstream Facilities as of December 31, 2017 and for the years ended December 31, 2017, 2016, and 2015:

	Approximate Capacity (MMcf/d)	Approximate Average Volumes (MMcf/d) Year Ended December 31, 2017	2016	2015
Gathering	75	37 [(1)]	N/A	N/A
Processing	190 [(2)]	109	103	122

(1) Reflects approximate average gathering volumes subsequent to our acquisition of the Douglas Gathering System on June 5, 2017.

(2) 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.

Water Solutions. We provide water business services through our 100% membership interest in BNN Water Solutions, LLC ("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 and a produced water disposal facility in Campbell County, Wyoming. Water Solutions is also the sole voting member and owns a 75.19% membership interest in BNN West Texas, LLC ("West Texas"), which owns a produced water gathering and disposal system in Reeves and Reagan Counties, Texas that is operated by Water Solutions and owns a 63% membership interest in BNN Colorado Water, LLC ("BNN Colorado"), which owns a freshwater storage reservoir and supply pipeline in Weld County, Colorado. These systems are 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. In January 2018, Water Solutions acquired a 100% membership interest in Buckhorn Energy Services, LLC and Buckhorn SWD Solutions, LLC (collectively, "BNN North Dakota"). BNN North Dakota owns a produced water gathering and disposal system in the Bakken basin with approximately 133,000 acres under dedication.

The table below sets forth certain information regarding the Water Solutions assets as of December 31, 2017 and for the years ended December 31, 2017, 2016, and 2015:

	Approximate Capacity Under Contract	Approximate Current Design Capacity (bbls/d)		Remaining Contract Life	Approximate Average Volumes (bbls/d) Year Ended December 31, 2017	2016	2015
Freshwater	68%	30,863	(1)	3	69,139	13,201	14,579
Gathering and Disposal	67%	45,000	(2)	7	31,511	11,307	7,951

(1) Represents design capacity at our BNN Western, LLC ("Western") owned facilities. Western also has access to an additional 144,539 bbls/d under supply arrangements, which are not included in the approximate current design capacity.

(2) Represents the combined daily disposal well injection capacity for the Western produced water gathering and disposal system acquired in December 2015 and the West Texas produced water gathering and disposal system which commenced operations by Water Solutions in March 2016.

Terminals. We provide crude oil storage and terminalling services through our 100% membership interest in Tallgrass Terminals, LLC ("Terminals"). Terminals owns and operates several assets providing storage capacity and additional injection points for the Pony Express System, including the crude oil terminal near Sterling, Colorado with approximately 1.3 million bbls of storage capacity (the "Sterling Terminal") and the crude oil terminal in Weld County, Colorado with four truck unloading skids capable of receiving up to 16,000 bbls per day (the "Buckingham Terminal"). Terminals also owns an approximately 60% membership interest in Deeprock Development, LLC ("Deeprock Development"), which owns a crude oil terminal in Cushing, Oklahoma with approximately 2.3 million bbls of storage capacity (the "Cushing Terminal"). As discussed in Note 20 – *Subsequent Events*, on January 2, 2018, Terminals acquired an approximately 38% membership interest in Deeprock North, LLC ("Deeprock North"), which was merged into Deeprock Development immediately following the acquisition. Deeprock North owned a terminal facility in Cushing, Oklahoma adjacent to the existing Deeprock Development facilities, bringing the total storage capacity of the Cushing Terminal to approximately 4.0 million barrels. In addition, Terminals is currently constructing both the Grasslands Terminal, which will connect to the Platteville Extension, and the Natoma Terminal in Central Kansas, and owns projects currently under development to provide additional storage capacity and other potential service opportunities, including approximately 550 acres in Cushing, Oklahoma and approximately 250 acres in Guernsey, Wyoming.

The table below sets forth certain information regarding Terminals as of December 31, 2017:

Approximate Storage Capacity (bbls)	Approximate Storage Capacity Under Contract	Weighted Average Remaining Contract Life
3,750,000	93%	19 years

Stanchion. During 2017, we established Stanchion Energy, LLC ("Stanchion"), to engage in the marketing of crude oil. Stanchion currently consists of three employees who primarily engage in the purchase and sale of crude oil.

Major Customers

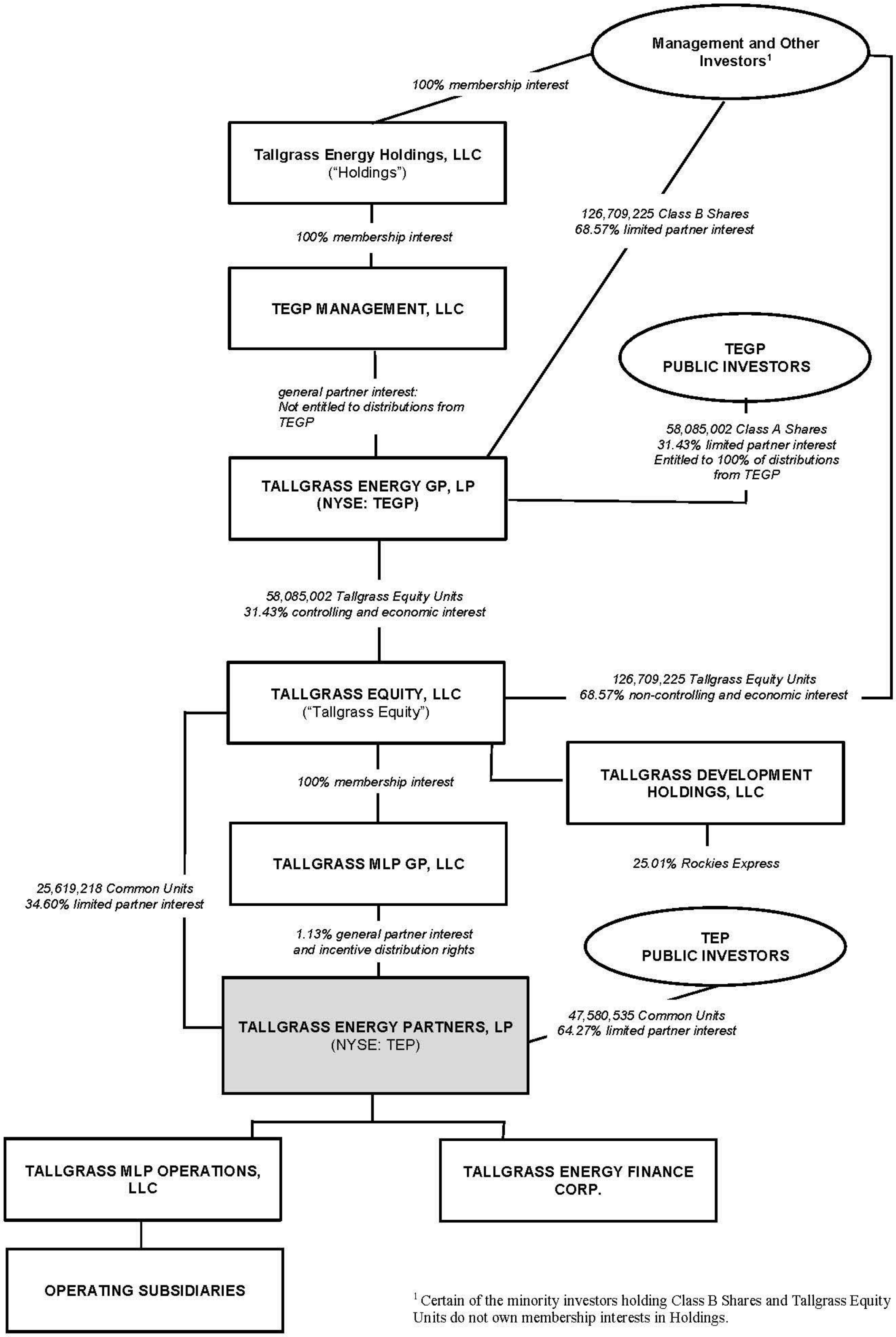
For the year ended December 31, 2017, Continental Resources accounted for approximately 15% of our revenues on a consolidated basis. The loss of this customer could have a material adverse effect on our financial results.

Organizational Structure

Our general partner interest and all our incentive distribution rights ("IDRs"), are held by our general partner, whose sole member is Tallgrass Equity, LLC ("Tallgrass Equity"). Tallgrass Equity also directly owned 20 million TEP common units as of December 31, 2017. On February 7, 2018, Tallgrass Equity acquired, among other interests, an additional 5,619,218 TEP common units from Tallgrass Development in connection with the merger of Tallgrass Development into a wholly-owned subsidiary of Tallgrass Equity, Tallgrass Development Holdings, LLC ("Tallgrass Development Holdings"), increasing Tallgrass Equity's total limited partner interest in TEP to 25,619,218 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 31.43% 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.

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 13, 2018 in a summary format.



[1] Certain of the minority investors holding Class B Shares and Tallgrass Equity Units do not own membership interests in Holdings.

Tallgrass Development

On February 7, 2018, Tallgrass Development was merged into Tallgrass Development Holdings. Prior to the merger, Tallgrass Development was controlled by its general partner, Tallgrass Energy Holdings and owned 5,619,218 of our common units, representing approximately 7.6% of our outstanding equity as of December 31, 2017.

Historically, we have acquired a number of our assets from Tallgrass Development. In connection with our initial public offering on May 17, 2013 (the "IPO"), Tallgrass Development contributed to us 100% of the membership interests in TIGT and TMID. Since then, we have acquired the following additional assets from Tallgrass Development: (1) in April 2014, a 100% membership interest in Trailblazer, (2) in four separate transactions, the most recent of which was effective on February 1, 2018, a 100% membership interest in Pony Express, (3) in January 2017, a 100% membership interest in NatGas and Terminals, (4) in March 2017, a 24.99% membership interest in Rockies Express, and (5) effective February 1, 2018, a 100% membership interest in Tallgrass Operations, LLC, which primarily owns certain administrative assets consisting primarily of information technology assets. In addition, in May 2016 Tallgrass Development assigned us its right to purchase a 25% membership interest in Rockies Express from a unit of Sempra U.S. Gas and Power ("Sempra") pursuant to the purchase agreement originally entered into between Tallgrass Development's wholly-owned subsidiary and Sempra in March 2016.

Pursuant to an Omnibus Agreement entered into upon the closing of our IPO, among us, TEP GP, Tallgrass Development Holdings (as successor to Tallgrass Development) and Tallgrass Energy Holdings (the "TEP Omnibus Agreement"), Tallgrass Development Holdings has granted us a right of first offer to acquire certain assets, if Tallgrass Development Holdings decides to sell such assets to a non-affiliate. The only asset currently owned by Tallgrass Development Holdings subject to such right of first offer is the 25.01% membership interest in Rockies Express. Tallgrass Development Holdings 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 Holdings or pursue any such joint acquisitions.

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 natural gas transportation, storage, gathering and processing assets, crude oil transportation, storage, gathering and terminalling assets, and water business services 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 2017 and in early 2018, as discussed in Note 3 – *Acquisitions* and Note 20 – *Subsequent Events*.

- *Terminals and NatGas.* In January 2017, we acquired 100% of the issued and outstanding membership interests in Terminals and 100% of the issued and outstanding membership interests in NatGas from Tallgrass Development for total cash consideration of $140 million.
- *Additional Membership Interest in Rockies Express.* In March 2017, we acquired an additional 24.99% membership interests in Rockies Express from Tallgrass Development for cash consideration of $400 million.
- *Douglas Gathering System.* In June 2017, we acquired 100% of the membership interests in DCP Douglas, LLC (subsequently renamed as Tallgrass Midstream Gathering, LLC) for approximately $128.5 million, subject to working capital adjustments.
- *Additional Interests in Deeprock Development.* In July 2017, we acquired an additional 40% membership interest in Deeprock Development from Kinder Morgan Cushing, LLC for cash consideration of approximately $57.2 million, net of cash acquired. We subsequently acquired an additional 9% membership interest in Deeprock Development from Deeprock Energy Resources LLC ("DER") for total consideration valued at approximately $13.1 million, consisting of approximately $6.4 million in cash and the issuance of 128,790 common units (valued at approximately $6.7 million based on the July 20, 2017 closing price of TEP's common units).
- *PRB Crude System.* In August 2017, we acquired 100% of the membership interests of Outrigger Powder River Operating, LLC (subsequently renamed as Tallgrass Crude Gathering, LLC, "TCG") for approximately $36 million. As discussed in Note 20 – *Subsequent Events*, we entered into an agreement in February 2018 with an affiliate of Silver Creek Midstream, LLC ("Silver Creek") to form Iron Horse Pipeline, a new joint venture pipeline to transport crude oil from the Powder River Basin. In addition to forming the joint venture, we also agreed to sell to Silver Creek our 100% membership interest in TCG. We expect to close the sale of TCG and the formation of the joint venture in February 2018.
- *Deeprock North.* In January 2018, we acquired a 38% membership interest in Deeprock North from Kinder Morgan Deeprock North Holdco, LLC for cash consideration of $19.5 million. Immediately following the acquisition, Deeprock North was merged into Deeprock Development. Subsequent to the acquisition and merger, Terminals owns approximately 60% of the combined entity.

- *Pawnee Terminal.* In January 2018, we entered into an agreement to acquire a 51% membership interest in the Pawnee, Colorado crude oil terminal from Zenith Energy Terminals Holdings, LLC for cash consideration of approximately $31 million, subject to working capital adjustments. We expect the transaction to close in the first quarter of 2018, subject to certain closing conditions.
- *BNN North Dakota.* In January 2018, we acquired a 100% membership interest in BNN North Dakota for cash consideration of approximately $95.0 million, subject to working capital adjustments.
- *Additional Interest in Pony Express.* In February 2018, we acquired the remaining 2% membership interest in Pony Express, along with administrative assets consisting primarily of information technology assets, from Tallgrass Development for cash consideration of approximately $60 million, bringing our aggregate membership interest in Pony Express to 100%.

Competition

All 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.

Additionally, pending and future construction projects, if and when brought online, may also compete with our natural gas transportation, storage, gathering and processing services, crude oil transportation, storage, gathering and terminalling services, and water transportation, gathering and disposal services. Further, natural gas as a fuel, and fuels derived from crude oil, compete with other forms of energy available to users, including electricity, coal, other liquid fuels and alternative energy. 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. Moreover, several other factors may influence the demand for natural gas and crude oil which in turn influences the demand for our services, 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.

Our principal competitors in our natural gas transportation and storage business include companies that own major natural gas pipelines, such as Spectra Energy Partners, Kinder Morgan, Northern Natural Gas Company, Southern Star Central Gas Pipeline, Inc., Energy Transfer Partners, EQT Midstream Partners, and Williams, some of whom also have existing storage facilities connected to their transportation systems that compete with our storage facilities.

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 Sinclair, Plains All American, Suncor, SemGroup, Magellan Midstream Partners, Anadarko, 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. In addition, Terminals encounters competition in the crude oil storage and terminalling business from similar facilities owned by Magellan Midstream Partners, NGL Energy Partners, Plains All American, Blueknight Energy Partners, SemGroup, and Enbridge Energy Partners.

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 other midstream companies, such as NGL Energy Partners, who compete with Water Solutions in areas of concentrated production activity.

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 Rockies Express Pipeline, 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 that interconnects with Overland Pass Pipeline is leased to a third party who has obtained a waiver for itself from the FERC from the tariff, filing and reporting requirements of the ICA, and our NGL pipeline that interconnects with ONEOK's Bakken NGL Pipeline is leased to a third party who is obligated to operate the leased pipeline in conformance with the ICA as a FERC regulated NGL pipeline.

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 interstate 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 interstate 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 discounted or negotiated rates as an alternative to cost-based rates and may grant market-based rates in certain circumstances. The FERC regulations also restrict interstate natural gas pipelines from sharing certain 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.

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. EPAct 2005 also amended the NGA and the NGPA to give the FERC authority to impose civil penalties for violations of these statutes of more than $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 more than $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 more than $1 million per violation per day.

The 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. In addition, the ICA imposes potential criminal liability for certain violations of the statute.

Certain Outstanding Notices Issued by the FERC

FERC Advanced Notice of Proposed Rulemaking, Revisions to Indexing Policies and Page 700 of FERC Form No. 6, Docket No. RM17-1-000

On November 2, 2016, the FERC issued an Advanced Notice of Proposed Rulemaking, under which the FERC is proposing changes to its regulation of oil pipelines in two different areas: (1) its policies regarding the permissible scope of rate increases based on its annual issuance of changes to the generic oil pipeline index, based on specific pipelines' earnings or their specific changes to costs; and (2) the reporting requirements for page 700 of FERC Form No. 6, Annual Report of Oil Pipeline Companies. The FERC's Advanced Notice of Proposed Rulemaking does not propose specific regulations, and may be followed by a Notice of Proposed Rulemaking proposing specific regulations or a Policy Statement announcing new or changed policies. Comments have been filed with the FERC by interested parties and the proceeding is pending before the FERC.

Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs, Docket No. PL17-1-000

On December 15, 2016, the FERC issued a Notice of Inquiry regarding the FERC's policy for recovery of income tax costs in pipeline cost of service rates. The FERC sought comments regarding how to address any double recovery resulting from the FERC's current income tax allowance and rate of return policies. This Notice of Inquiry follows the U.S. Court of Appeals for the District of Columbia Circuit holding in *United Airlines, Inc., et al. v. FERC* that the FERC failed to demonstrate that there is no double recovery of taxes for a partnership pipeline as a result of the income tax allowance and return on equity determined pursuant to the discounted cash flow methodology. Comments have been filed with the FERC by interested parties and the proceeding is pending before the FERC.

Examples of Our Dockets at the FERC

Rockies Express Zone 3 Capacity Enhancement Project

On March 31, 2015 in Docket No. CP15-137-000, Rockies Express filed with the FERC an application for authorization to construct and operate (1) three new mainline compressor stations located in Pickaway and Fayette Counties, Ohio and Decatur County, Indiana; (2) additional compression at one existing compressor station in Muskingum County, Ohio; and (3) certain ancillary facilities. As proposed, the facilities would increase the Rockies Express Zone 3 east-to-west mainline capacity by 0.8 Bcf/d. Pursuant to the FERC's obligations under the National Environmental Policy Act, FERC staff issued an Environmental Assessment for the project on August 31, 2015. On February 25, 2016, the FERC issued a Certificate of Public Convenience and Necessity authorizing Rockies Express to proceed with the project. On March 14, 2016, Rockies Express commenced construction of the project facilities. The project was placed in-service for the 0.8 Bcf/d on January 6, 2017.

TIGT 2015 General Rate Case Filing

On October 30, 2015, in Docket No. RP16-137-000, *et seq.*, TIGT filed a general rate case with the FERC pursuant to Section 4 of the NGA. The general rate case was ultimately resolved by settlement, which the FERC approved on November 2, 2016, and a compliance filing that modernized TIGT’s FERC Gas Tariff, consistent with prior FERC orders, which the FERC accepted on March 16, 2017. Per the terms of the settlement, TIGT is required to file a new general rate case on May 1, 2019 (provided that such rate case is not pre-empted by a pre-filing settlement).

For additional information, see Note 16 – *Regulatory Matters*.

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.

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 consequence 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. In addition, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, or PIPES Act, reauthorized PHMSA's oil and gas pipeline programs through 2019 and gave PHMSA power to issue emergency orders upon finding an imminent hazard, required PHMSA to issue safety standards for underground natural gas storage facilities, set deadlines for conducting post-inspection briefings and making findings, required liquid pipeline operators to undertake new safety measures, and required certain updates to the PHMSA website.

Additionally, PHMSA is also currently considering changes to its regulations. On December 14, 2016, PHMSA issued an interim final rule, or IFR, that addresses safety issues related to downhole facilities, including well integrity, well bore tubing, and casing at underground natural gas storage facilities. The IFR incorporates by reference two of the American Petroleum Institute's Recommended Practice standards and mandates certain reporting requirements for operators of underground natural gas storage facilities. Operators of natural gas storage facilities were given one year from January 18, 2017, the effective date of the IFR, to implement this first set of PHMSA regulations governing underground storage fields. PHSMA determined, however, that it will not issue enforcement citations to any operators for violations of provisions of the IFR that had previously been non-mandatory provisions of American Petroleum Institute Recommended Practices 1170 and 1171 until one year after PHMSA issues a final rule. On January 13, 2017, PHMSA finalized new hazardous liquid pipeline safety regulations. Among other things, the final rule requires additional event-driven and periodic inspections, requires the use of leak detection systems on all hazardous liquid pipelines, modifies repair criteria, and requires certain pipelines to eventually accommodate in-line inspection tools. It is unclear when or if this rule will go into effect as, on January 20, 2017, the Trump Administration requested that all regulations that had been sent to the Office of the Federal Register, but not yet published, be immediately withdrawn for further review. Accordingly, the anticipated January 2017 rulemaking was never published in the Federal Register.

Also, on April 8, 2016, PHMSA published a notice of proposed rule-making, or NPRM, addressing natural gas transmission and gathering lines. The proposed rule would include changes to existing integrity management requirements and would expand assessment and repair requirements to pipelines in areas with medium population densities (referred to as Moderate Consequence Areas or MCAs), along with other changes. This NPRM builds on an Advisory Bulletin PHMSA issued 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. 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.

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. 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.

Trailblazer

Starting in 2014, Trailblazer's operating capacity was decreased as a result of smart tool surveys that identified approximately 25 - 35 miles of pipe as potentially requiring repair or replacement. During 2016 and 2017, Trailblazer incurred approximately $21.8 million of remediation costs to address this issue, including replacing approximately 8 miles of pipe. To date the pressure and capacity reduction has not prevented Trailblazer from fulfilling its firm service obligations at existing subscription levels or had a material adverse financial impact on us. However, Trailblazer intends to continue performing remediation to increase and maximize its operating capacity over the long-term and expects to spend in excess of $20 million during 2018 for this pipe replacement and remediation work. Trailblazer is exploring all possible cost recovery options to recover expenditures, including recovery through a general rate increase, negotiated rate agreements with its customers, or other FERC-approved recovery mechanisms.

In connection with our acquisition of Trailblazer in April 2014, TD agreed to indemnify TEP for certain out of pocket costs related to repairing or remediating the Trailblazer Pipeline. The contractual indemnity was capped at $20 million and subject to an annual $1.5 million deductible. TEP has received the entirety of the $20 million from TD pursuant to the contractual indemnity as of December 31, 2017.

Pony Express

In connection with certain crack tool runs on the Pony Express System completed in 2015 and 2016, Pony Express completed approximately $10 million of remediation in 2016 for anomalies identified on the Pony Express System associated with portions of the pipeline that were converted from natural gas to crude oil service, and completed additional remediation in 2017 on the Pony Express System of approximately $8.2 million.

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 long-term trend in environmental legislation and regulations will eventually move 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.

The EPA finalized a rule, effective August 2, 2016, under the New Source Performance Standard Program, or NSPS Program, to limit methane emissions from the oil and gas and transmission sectors. The rule sets additional emissions limits for volatile organic compounds and regulates methane emissions for new and modified sources in the oil and gas industry. The EPA is currently reconsidering the rule and has proposed to stay its requirements. However, the rule currently remains in effect. The EPA also finalized a rule regarding the alternative criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes. Also, effective January 17, 2017 the Bureau of Land Management of the U.S. Department of the Interior, or BLM, imposed new rules to reduce venting, flaring and leaks during oil and natural gas production activities on onshore federal and Indian lands. In December 2017, the BLM issued a final rule that temporarily suspends or delays these requirements until January 2019, while the BLM considers revising or rescinding these requirements.

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, which was signed on April 22, 2016 by 175 countries, including the United States. The Paris Agreement 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. However, in August of 2017, the United States informed the United Nations of its intent to withdraw from the Paris Agreement. The earliest possible effective withdrawal date from the Paris Agreement is November 2020.

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; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act, or SDWA, and has released draft permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where the EPA is the permitting authority. 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. Local governments 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, and in some cases, may seek to ban hydraulic fracturing entirely. Some state and local authorities have considered or imposed new laws and rules related to hydraulic fracturing, including temporary or permanent bans, additional permit requirements, operational restrictions and chemical disclosure obligations on hydraulic fracturing in certain jurisdictions or in environmentally sensitive areas.

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 the 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 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 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. In 2015, the EPA and the U.S. Army Corps of Engineers adopted a rule to clarify the meaning of the term "waters of the United States" with respect to federal jurisdiction. This rule has been challenged in federal courts at both the appellate and district court levels. Based on a January 2018 U.S. Supreme Court decision, only the district courts were determined to have jurisdiction to hear the challenges. As a result, stays entered by district courts remain in effect, however, a stay previously issued by the Sixth Circuit is expected to be withdrawn. Accordingly, although the rule is currently stayed in several states pursuant to a district court decision, it could become effective in other states absent additional agency or judicial action. Many interested parties believe that the rule expands federal jurisdiction under the CWA. In July 2017, the EPA and the U.S. Army Corp of Engineers published a proposed rule to rescind the 2015 rule. In February 2018, the agencies also published a final rule adding a February 6, 2020 applicability date to the 2015 rule. The final rule adding this applicability date is currently subject to litigation. Regulations promulgated pursuant to the CWA and analogous state laws require that entities that discharge into federal and/or 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, heating purposes and other natural gas usages, 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. 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 generally 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, surface use agreements, or licenses from landowners or governmental authorities, permitting the use of such land for our operations. We believe we have satisfactory title to the material portions of the land on which our pipelines and facilities are owned by us in fee title. 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, surface use agreements or licenses between us, as grantee, and a third party, as grantor. We believe that we have satisfactory rights to all of the material parcels in which our interest derives from leases, easements, rights-of-way, permits and licenses.

Insurance

We generally share insurance coverage with Tallgrass Energy Holdings and TEGP, for which we reimburse Tallgrass Energy Holdings and its affiliates for our share of the cost pursuant to the terms of the TEP Omnibus Agreement. This shared insurance program includes general and excess liability insurance, auto liability insurance, workers' compensation insurance, pollution, business interruption and 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 our employees are employed by Tallgrass Management, LLC, a wholly-owned subsidiary 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 Energy Holdings (and its affiliates) and our general partner, respectively, for the provision of various general and administrative services for our benefit and for direct expenses incurred by Tallgrass Energy Holdings (and its affiliates) 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;
- 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;
- the actual and anticipated future prices, and the volatility thereof, of natural gas, crude oil and other commodities;
- changes in the fees we charge for our services, including firm services and interruptible services;
- our ability to identify, develop, and complete internal growth projects or expansion capital expenditures on favorable terms to improve optimization of our current assets;
- 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;
- 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;
- the effect of worldwide energy conservation measures;
- prevailing economic conditions;
- 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, for services provided to us;
- the cost of pursuing and completing acquisitions and capital expansion projects, 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 operations, cash flows and ability to make cash distributions to our unitholders will be adversely affected.

A substantial majority of our contracts for transporting, storing, and processing our customers' products on our systems are long-term firm fee contracts with terms of various durations. For the year ended December 31, 2017, approximately 92% of our natural gas transportation and storage revenues were generated under firm fee transportation and storage contracts and approximately 88% of our crude oil transportation revenues were generated under firm fee transportation contracts. As of December 31, 2017, the weighted average remaining life of our long-term natural gas transportation contracts and natural gas storage contracts at TIGT and Trailblazer was approximately four years each, and the crude oil transportation contracts was approximately three years, reflective of the Continental Resources contract extension effective January 1, 2018. In addition, a majority of Rockies Express' west-to-east pipeline capacity is subject to long-term firm fee contracts that expire in 2019 and a significant amount of Rockies Express' revenue in 2017 was derived under these contracts.

We 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, our natural gas transportation, storage and processing customers with long-term fee-based contracts may desire to enter into contracts with reduced fees, and may be unwilling to enter into long-term contracts at all. In addition, a significant portion of the long-term contracts for the Pony Express Pipeline expire in 2019 and those customers may unilaterally decide whether to renew such contracts. If these contracts are not renewed, Pony Express' ability to enter into replacement long-term contracts would be limited. Under current FERC policy, Pony Express is generally prohibited from entering into new long-term contracts that grant contract shippers priorities in prorationing under the ICA unless such contract relates to an increase in the capacity of the Pony Express Pipeline.

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 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 directly and indirectly serve;
- the extent to which the current and potential customers in our markets are willing to provide firm fee commitments on a long-term basis; and
- the effects of federal, state or local laws or regulations on the contracting practices of our customers.

During periods of price reduction and high volatility in the commodity markets, we expect customers will generally be less likely to enter into long-term firm fee contracts, and even if they enter into such contracts, may only be willing to provide acreage dedications to our assets rather than firm fee commitments. Acreage dedications typically do not require our customers to pay us unless they utilize our assets, and they may also be subject to challenge in bankruptcy proceedings.

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.

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 extent to which our customers actually utilize our assets. Periods of price reduction and high volatility in the commodity markets 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.

For example, in 2016, Ultra Resources, Inc., or Ultra, defaulted on its firm transportation service agreement with Rockies Express for approximately 0.2 Bcf/d through November 11, 2019, and as a result, Rockies Express filed a lawsuit seeking approximately $303 million in damages and other relief. Approximately 13% of Rockies Express' revenue in 2015 was derived from the Ultra contract. In April 2016, Ultra filed for bankruptcy protection and in January 2017, Rockies Express and Ultra agreed to settle Rockies Express' claim against Ultra's bankruptcy estate. In accordance with the settlement agreement, Ultra made a cash payment to Rockies Express of $150 million on July 12, 2017, and entered into a new, seven-year firm transportation agreement with Rockies Express commencing December 1, 2019, for west-to-east service of 0.2 Bcf/d at a rate of approximately $0.37, or approximately $26.8 million annually.

In addition, Triad Hunter, LLC, or Triad, sought bankruptcy relief in December 2015. At the time Triad commenced the bankruptcy proceedings, Triad and Rockies Express were parties to a precedent agreement that provided Triad with an approximate 0.1 Bcf/d of firm capacity in connection with the Rockies Express Zone 3 Capacity Enhancement Project. In order to settle its claim, Rockies Express agreed to amend certain material terms of the precedent agreement, including reducing Triad's firm capacity under the precedent agreement to an approximate 0.05 Bcf/d.

Although the Triad and Ultra claims were ultimately settled, and on terms we view as favorable, future bankruptcy proceedings with a counterparty may not result in a favorable settlement for us.

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. Although we generally ask for credit support from customers we deem to not be creditworthy or upon a deterioration of the financial condition of an existing customer, some customers 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 decline and volatility in crude oil prices from the second half of 2014 through the first half of 2016, 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.

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, 2017, Continental Resources accounted for approximately 15% of our revenues on a consolidated basis. In addition, for the year ended December 31, 2017, approximately 51% of our consolidated revenues were represented by the top ten customers on our Pony Express System. We own a 49.99% membership interest in Rockies Express, which is not consolidated for financial reporting purposes. Approximately 20%, 13%, and 12%, respectively, of Rockies Express' total revenues as of December 31, 2017 were represented by Rockies Express' three largest non-affiliated shippers.

We may be unable to negotiate extensions or replacements of contracts with key customers on favorable terms. For additional detail, see *"—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 operations, cash flows and ability to make cash distributions to our unitholders will be adversely affected."*

In addition, some of these key customers may experience financial problems that could have a significant effect on their creditworthiness. For example, Rockies Express terminated its contract with its third largest non-affiliated shipper by total 2015 revenue, Ultra, in March 2016. For more detail regarding Ultra, see *"—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."*

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 indebtedness 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.

If we are unable to make acquisitions on economically acceptable terms, 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. Many factors could impair our access to future midstream assets. A material decrease in divestitures of midstream energy assets by industry participants 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. Prior to February 7, 2018, Tallgrass Development was our primary source of acquisitions. Now that Tallgrass Development has divested its entire asset portfolio and merged out of existence, our growth through acquisitions will rely almost exclusively on buying assets or businesses from third parties.

Our future growth and ability to increase distributions will be limited if we are unable to make accretive acquisitions because, among other reasons, (i) we are unable to identify attractive acquisition opportunities, (ii) we are unable to negotiate acceptable purchase contracts, (iii) we are unable to obtain financing for these acquisitions on economically acceptable terms, (iv) we are outbid by competitors or (v) 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. For example, we completed a number of acquisitions in 2017, including the acquisition of 100% of the membership interests in Terminals and 100% of the membership interests in NatGas from Tallgrass Development in January 2017, an additional 24.99% membership interest in Rockies Express from Tallgrass Development in March 2017, 100% of the membership interests in DCP Douglas, LLC from DCP Midstream in June 2017, an additional 40% membership interest in Deeprock Development from Kinder Morgan in July 2017, and 100% of the membership interests of TCG from Outrigger Energy in August 2017. If certain risks or unanticipated liabilities were to arise, the desired benefits of these acquisition may not be fully realized and our future financial performance and results of operations could be negatively impacted.

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 successfully integrate the assets or businesses we acquire;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new geographic areas or business lines; and
- a decrease in liquidity and increased leverage as a result of using significant amounts of available cash or debt to finance an acquisition.

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

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

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

The Throughput and Deficiency Agreements 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 Throughput and Deficiency Agreements, or 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 for a period of six months following termination, 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. As of December 31, 2017, Pony Express had a cumulative net deficiency balance of $88.4 million and a cumulative shipper incremental balance of $1.5 million.

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.

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. Some of our competitors have assets in closer proximity to certain hydrocarbon supplies and have available idle capacity in existing assets that may require no or minimal capital investments for use. For example, several pipelines access many of the same basins as our assets and provide transport to customers in the Rocky Mountain, Appalachian Mountain and Midwest regions of the United States, such as the Dakota Access Pipeline, Saddlehorn-Grand Mesa Pipeline and White Cliffs Pipeline that compete with the Pony Express Pipeline. 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). Furthermore, Tallgrass Energy Holdings 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 and Appalachian Mountain regions) has been 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, other fuels and alternative energy. 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 decreasing demand.

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. Construction projects require significant amounts of capital and involve numerous regulatory, environmental, political, legal and operational uncertainties, many of which are beyond our control. 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. For example, in June 2014, Michels Corporation, or Michels, filed a complaint and request for relief against Rockies Express as a result of work performed by Michels to construct the Seneca Lateral Pipeline in Ohio. Michels sought unspecified damages from Rockies Express and asserted claims of breach of contract, negligent misrepresentation, unjust enrichment and quantum meruit, and also filed notices of Mechanic's Liens in Monroe and Noble Counties, asserting $24.2 million as the amount due. In February 2017, Rockies Express and Michels resolved the claims brought by Michels in exchange for a $10 million cash payment by Rockies Express.

Although we evaluate and monitor each capital spending project and try to anticipate difficulties that may arise, such delays or cost increases may arise as a result of factors that are beyond our control, including:

- denial or delay in issuing requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of modular components and/or construction materials;
- severe adverse weather conditions, natural disasters, or other events (such as equipment malfunctions, explosions, fires, releases) affecting our facilities, or those of vendors and suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- changes in market conditions impacting long lead-time projects;
- market-related increases in a project's debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors, or sub-contractors involved with a project.

These projects also involve numerous economic uncertainties and the cash flow generated from these projects may not meet expectations or project estimates. Moreover, we may not receive any material increase in operating cash flow from a project for some time or at all. For instance, with respect to the Rockies Express Zone 3 Capacity Enhancement Project, substantially all the construction expenditures were incurred during 2015 and 2016, yet Rockies Express only received increases in cash flow from the project after it was placed in-service in January 2017. In 2017, we began incurring construction expenditures in connection with commencing construction of the Platteville Extension Project on the Pony Express System and the Cheyenne Connector Pipeline. However, we will not receive any increases in cash flow from these projects until such project is completed and placed in-service.

The 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 also 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, nearly 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 have certain long-term fixed priced natural gas and crude oil transportation contracts that cannot be adjusted even if our costs increase. As a result, our costs could exceed our revenues.

As of December 31, 2017, approximately 45% of our contracted natural gas transportation firm capacity was 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.

Rates under Pony Express' TDAs are typically subject to change only per contract terms and conditions, including Pony Express' 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.

A significant amount of the revenue currently generated by the Pony Express System and the Rockies Express Pipeline are from contracts that contain most favored nations rights, limiting flexibility to offer certain capacity to new shippers.

Approximately 90% of the Pony Express System's current available capacity is provided to committed shippers under long-term TDAs. Some of the TDAs contain most favored nations rights, or MFNs, 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. Triggering the MFNs on the TDAs could lead to a reduction in revenue generated by Pony Express, which could have a material adverse effect on our revenues, cash flow, results of operations and our ability to make distributions to our unitholders.

Rockies Express' foundation and anchor shippers for west-to-east service hold certain MFNs granting them a right to a rate reduction in certain instances where Rockies Express provides service to another shipper at a rate lower than the foundation or anchor shipper rate for a term of one year or greater or, in the case of the foundation shipper, from certain specified receipt locations. The MFNs effectively limit Rockies Express' flexibility in negotiating rates for some of its services with other shippers, because triggering the MFNs of the foundation and anchor shippers could lead to a reduction in the rates that Rockies Express charges, which could have a material adverse effect on Rockies Express' revenues, cash flow and results of operations, which in turn could impair our ability to make distributions to our unitholders.

If third-party pipelines or other facilities interconnected to our systems become partially or fully unavailable, if the volumes we transport do not meet the quality requirements of such pipelines or facilities, or if claims are made against us for events that occur downstream of our interconnection with third-party 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 ONEOK Bakken Pipeline, L.L.C., Whiting Petroleum, and others. For 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 upstream of the Belle Fourche Pipeline) and the Double H Pipeline owned by Kinder Morgan, which are responsible for delivering a substantial portion of the crude oil for transportation on the Pony Express System. In addition, part 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 Cushing Terminal, which we do not operate.

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, extended unscheduled maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements, conversion to another form of commodity transportation service, cessation of operations, 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.

In addition, our interconnection with third-party facilities may result in claims being made against us for events that occur downstream of our pipelines. For example, TIGT has been named as a defendant in a lawsuit for damages arising from a gas leak and home explosion that occurred in June 2014 in Finney County, Kansas. Although TIGT did not directly distribute natural gas to the home in question, the plaintiffs nonetheless allege that TIGT committed torts and otherwise violated federal safety laws. TIGT believes the claims are without merit and intends to vigorously defend them.

If the costs to us to access and transport on these third-party pipelines or any alternative pipelines significantly increase, if any of these pipelines or other midstream facilities become unable to receive, transport, store or process products from our assets, if the volumes we transport or process do not meet the quality requirements of such pipelines or facilities, or if claims are made against us for events that occur downstream of our interconnection with third-party facilities, our revenues and our ability to make quarterly cash distributions to our unitholders could be adversely affected.

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, Appalachian 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 are provided through a limited number of assets with a relatively high concentration 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.

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 and construction of new assets are both 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.

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.

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

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

The revenue in our Gathering, Processing & Terminalling segment largely depends on the amount of natural gas that our customers actually deliver to our natural gas processing plants.

During the year ended December 31, 2017, approximately 17%, 53%, and 30% of TMID's Adjusted EBITDA came from firm fee, volumetric fee, and commodity sensitive contracts, respectively. On these volumetric fee contracts, our revenue is largely tied to the amount of natural gas that our customers actually deliver to 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 Gathering, Processing & Terminalling segment will decline. As natural gas, crude oil or NGL prices decline, 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 2014 through 2016 contributed to a significant drop in actual volumes from several producers from which TMID receives natural gas for processing. If processing volumes at TMID do not continue recovering over time, we could have an impairment of the goodwill at the TMID reporting unit, which is a component of our Gathering, Processing & Terminalling 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 are exposed to direct commodity price risk with respect to some of our processing revenues and the utilization of commodity derivatives by Stanchion, and our exposure to direct commodity price risk may increase in the future.

Our Gathering, Processing & Terminalling 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. 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. For example, from the second half of 2014 through the first half of 2016, natural gas and crude 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.

In 2017, we also began utilizing commodity derivatives in connection with the operations of our crude oil marketing subsidiary, Stanchion. Our portfolio of derivative and other energy contracts may consist of contracts to buy and sell commodities that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. If a performance failure were to occur in one of our contracts, we might incur losses in addition to amounts, if any, already recognized in our financial statements or paid to, or received from, counterparties. As a result, our business, results of operations, financial condition and ability to pay distributions to our unitholders may 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 and our customers 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 laws and regulations;
- technological advancements that may drive further increases in production and reduction in costs of developing crude oil and natural gas shale plays;
- the price and availability of other forms of energy, including alternative energy which may benefit from government subsidies;
- adoption of various energy efficiency and conservation measures;
- prices for natural gas, crude oil and NGLs;
- decisions of the members of the Organization of the Petroleum Exporting Countries, or OPEC, regarding price and production controls;
- increased costs to explore for, develop, produce, gather, process and transport natural gas or crude oil;
- 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 from the second half of 2014 through the first half of 2016 experienced a sustained period of decline and volatility in natural gas and crude oil prices. Any prolonged downturns in the oil and gas industry could result in a reduction in demand for our services 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 volatility and sustained lower prices for crude oil and refined products from the second half of 2014 through the first half of 2016 led to a decline in drilling activity, production and refining of crude oil, and import levels in these areas. For example, in response to this volatility and lower prices, a number of producers in our areas of operation significantly reduced their capital budgets and drilling plans in 2015 through 2017. Even if those producers increase their capital budgets in areas we serve in 2018, it may take months before the increased capital spending has the possibility of resulting in increased utilization of our assets. In addition, production may fluctuate for other reasons, including, for example, in the case of crude oil, the extent to which the members of OPEC abide by agreements 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 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, crude oil and liquids operations are subject to extensive regulation by federal, state and local regulatory authorities which could have a material adverse effect on our business, financial condition, and results of operations.

We provide open-access interstate transportation service on our interstate natural gas transportation systems pursuant to tariffs approved by the FERC. Our interstate natural gas transportation and storage operations are regulated by the FERC, under the NGA, the NGPA, and the EPAct 2005. The Rockies Express Pipeline, the TIGT System and the Trailblazer Pipeline each operate 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 that interconnects with Overland Pass Pipeline is leased to a third party that has obtained a FERC waiver from the tariff, filing and reporting requirements of the ICA, and our NGL pipeline that interconnects with ONEOK's Bakken NGL Pipeline is leased to a third party that is obligated to operate the leased pipeline in conformance with the ICA as a FERC-regulated NGL pipeline.

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 and NGL 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 rates that we may charge for our natural gas transportation and storage services are established through the FERC's ratemaking process. The maximum applicable recourse rates and terms and conditions for service are set forth in our FERC-approved tariffs.

For example, TIGT filed a general rate case with the FERC pursuant to Section 4 of the NGA in October 2015, which resulted in a settlement that was approved by an order issued by the FERC on November 2, 2016. The settlement established settlement rates to be effective through at least April 30, 2019. In the event the assumptions relied upon during settlement negotiations were incorrect or the actual costs incurred to operate the TIGT System increase, TIGT's cash flows and its results of operations could be adversely affected.

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, and fixed fuel and lost and unaccounted for charges) 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 interstate 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 interstate 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. Interstate 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. An interstate 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 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.

Pony Express Pipeline's tariff rates may not always be eligible for increases to reflect a FERC index adjustment. For example, on November 2, 2016, the FERC issued an Advanced Notice of Proposed Rulemaking, under which the FERC is proposing changes to its policies regarding the permissible scope of rate increases based on its annual issuance of changes to the generic oil pipeline index, based on specific pipelines' earnings or their specific changes to costs. The FERC's Advanced Notice of Proposed Rulemaking does not propose specific regulations, and may be followed by a Notice of Proposed Rulemaking proposing specific regulations or a Policy Statement announcing new or changed policies. This proceeding is pending before the FERC.

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 and upgrades, 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 natural gas 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 the 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 information 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. The ICA also prevents crude oil and NGL pipelines from disclosing certain shipper information without the shipper's consent.

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 or customer. 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 more than $1 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, on November 22, 2017, in FERC Docket No. OR17-2-000, the FERC issued an Order on Petition for Declaratory Order addressing whether certain specific hypothetical transactions between a petroleum liquids pipeline and its marketing affiliate proposed by the petitioner, Magellan Midstream Partners, L.P., would violate the requirements of the ICA or the FERC’s regulations and policies. The FERC concluded that certain transactions proposed by the petitioner could be inconsistent with the ICA and the FERC’s policies. Various market participants filed requests for clarification or, in the alternative, rehearing of the November 22, 2017 declaratory order. On January 22, 2018, the FERC issued an order granting rehearing for further consideration, which afforded the FERC additional time to consider and rule on the pending clarification/rehearing requests. The outcome of this proceeding and any related proceeding(s) may require us to modify the business practices between our petroleum liquids pipelines regulated by FERC and our affiliated marketer, Stanchion. To the extent the foregoing proceedings result in substantial new restrictions on the transactions between petroleum liquids pipelines and their affiliated shippers, the business activities of Stanchion could be affected.

The FERC may also 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. Further, the FERC is reviewing, and may possibly revise, its policies for analyzing whether proposed natural gas facilities are in the public convenience and necessity, including its Policy Statement on Certification of New Interstate Natural Gas Facilities issued in 1999. A change in such policies could delay or prevent the FERC's approval of proposed natural gas facilities, which could have a material impact on our business. 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 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.

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 previously 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.

Further, the FERC's actions are subject to court challenge, which may have broader implications for other regulated pipelines. For example, in July 2016, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in *United Airlines, Inc., et al. v. FERC*, finding that the FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in the cost of service underlying its rates in addition to the discounted cash flow return on equity would not result in the pipeline partnership owners double-recovering their income taxes. The court vacated the FERC's order and remanded to the FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance.

On December 15, 2016, the FERC issued a Notice of Inquiry regarding the FERC's policy for recovery of income tax costs in pipeline cost of service rates. The FERC sought comments regarding how to address any double recovery resulting from the FERC's current income tax allowance and rate of return policies following the holding in *United Airlines, Inc., et al. v. FERC*. Comments have been filed with the FERC by interested parties and the proceeding is pending before the FERC. There is not likely to be a definitive resolution of these issues for some time, and the ultimate outcome of this proceeding is not certain and could result in changes going forward to the FERC's treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity. Depending upon the resolution of these issues, the cost of service rates of our interstate natural gas pipelines and interstate crude oil pipeline could be affected to the extent we propose new rates or changes to our existing rates or if our rates are subject to complaint or challenge by the FERC.

On December 22, 2017, federal legislation known as the "Tax Cuts and Jobs Act" was enacted, which made various changes to the United States tax laws, including reducing the highest marginal U.S. federal corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017, adjusting the individual income tax brackets, and establishing limited deductions for certain income from "pass-through" entities. If FERC requires us to establish new tariff rates that reflect changes resulting from the Tax Cuts and Jobs Act, it is possible that certain tariff rates could be reduced, which could adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

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.

We are subject to numerous hazards and operational risks.

Our operations are subject to all the risks and hazards typically associated with transportation, storage, terminalling, 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.

For example, on January 31, 2018, Rockies Express experienced an operational disruption on its Seneca Lateral due to a pipe rupture and natural gas release in a rural area in Noble County, Ohio. There were no injuries reported and no evacuations, however, the release required Rockies Express to shut off the flow through the segment. Repairs are underway to return the segment to service as soon as possible and a root cause investigation is ongoing. As an additional example, approximately 10,000 bbls of crude oil were released at the Sterling Terminal in January 2017 as a result of a defective roof drain system on a storage tank. While the release was restricted to the containment area designed for such purpose and approximately 9,000 bbls were ultimately recovered, the total cost to remediate the release was approximately $600,000.

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. Any such service interruption or alteration could limit our ability to satisfy customer requirements, could obligate us to provide reservation charge credits to customers for constrained capacity, or could allow existing customers to be solicited by other companies for potential new projects that would compete directly with our 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. 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 or cyber security threats. 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* 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. In April 2017, PHMSA issued a final rule that increased the per-day violation penalty to $209,002 and the maximum penalty for a related series of violations to $2,090,022 effective April 27, 2017. On January 13, 2017, PHMSA finalized new hazardous liquid pipeline safety regulations extending certain regulatory reporting requirements to all hazardous liquid gathering (including oil) pipelines. The final rule requires additional event-driven and periodic inspections, requires the use of leak detection systems on all hazardous liquid pipelines, modifies repair criteria, and requires certain pipelines to eventually accommodate in-line inspection tools. It is unclear when or if this rule will go into effect as, on January 20, 2017, the Trump Administration requested that all regulations that had been sent to the Office of the Federal Register, but not yet published, be immediately withdrawn for further review. Accordingly, the anticipated January 2017 rulemaking was never published in the Federal Register. In addition, on April 8, 2016, PHMSA published a notice of proposed rule-making, or NPRM, addressing natural gas transmission and gathering lines. The proposed rule would include changes to existing integrity management requirements and would expand assessment and repair requirements to pipelines in MCAs, along with other changes. Further, this NPRM would build on the requirements in an Advisory Bulletin PHMSA issued 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. Comments on the NPRM were due on July 7, 2016; further action is pending. We are still monitoring and evaluating the effects of these proposed and recently finalized requirements on our operations.

On June 22, 2016, President Obama signed the PIPES Act, that reauthorizes PHMSA's oil and gas pipeline programs through 2019 and provides for the following new mandates, among others:

- Empowers PHMSA to issue emergency orders to individual operators, groups of operators, or the industry upon a written finding that an unsafe condition or practice constitutes or is causing an imminent hazard;
- Requires PHMSA, in consultation with other federal agencies, to issue minimum safety standards for underground natural gas storage facilities within two years;
- Requires PHMSA to conduct post-inspection briefings outlining any concerns within 30 days and providing written preliminary findings within 90 days to the extent practicable;
- Requires liquid pipeline operators to provide safety data sheets on spilled product to the designated federal on-scene coordinator and appropriate state and local emergency responders within 6 hours of telephonic or electronic notice of an accident to the National Response Center; and
- Requires PHMSA to publish updates on its website every 90 days on the status of an outstanding final rule required by a statutory mandate.

On December 14, 2016, PHMSA issued an IFR that addresses safety issues related to downhole facilities, including well integrity, well bore tubing and casing at underground natural gas storage facilities. The IFR incorporates by reference two of the American Petroleum Institute’s Recommended Practice standards and mandates certain reporting requirements for operators of underground natural gas storage facilities. Operators of natural gas storage facilities were given one year from January 18, 2017, the effective date of the IFR, to implement this first set of PHMSA regulations governing underground storage fields. PHMSA determined, however, that it will not issue enforcement citations to any operators for violations of provisions of the IFR that had previously been non-mandatory provisions of American Petroleum Institute Recommended Practices 1170 and 1171 until one year after PHMSA issues a final rule.

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, such as the MCAs proposed by the April 2016 NPRM, can have a significant impact on the costs to perform integrity testing and repairs.

For example, starting in 2014, Trailblazer’s operating capacity was decreased as a result of smart tool surveys that identified approximately 25 - 35 miles of pipe as potentially requiring repair or replacement. During 2016 and 2017, Trailblazer incurred approximately $21.8 million of remediation costs to address this issue, including replacing approximately 8 miles of pipe. To date the pressure and capacity reduction has not prevented Trailblazer from fulfilling its firm service obligations at existing subscription levels or had a material adverse financial impact on us. However, Trailblazer intends to continue performing remediation to increase and maximize its operating capacity over the long-term and expects to spend in excess of $20 million during 2018 for this pipe replacement and remediation work. Trailblazer is exploring all possible cost recovery options to recover expenditures, including recovery through a general rate increase, negotiated rate agreements with its customers, or other FERC-approved recovery mechanisms.

Additionally, in connection with certain crack tool runs on the Pony Express System completed in 2015 and 2016, Pony Express completed approximately $10 million of remediation in 2016 for anomalies identified on the Pony Express System associated with portions of the pipeline converted from natural gas to crude oil service, and completed additional remediation in 2017 on the Pony Express System of approximately $8.2 million.

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.

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 potentially material unanticipated capital and operating expenditures for repairs or upgrades.

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 proposed regulations implementing the Pipeline Safety Act of 2011 and future regulations implementing the PIPES Act 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.

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, storage, gathering and terminalling, natural gas transportation, storage, gathering 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 and which the EPA has relied upon as authority for adopting climate change regulatory initiatives;
- CWA and analogous state and local laws, which regulate discharge of pollutants or fill material from our facilities to state and federal waters, including wetlands and which require compliance with state water quality standards;
- 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;
- The SDWA, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and controls the waste fluids from disposal wells into below-ground formations;
- OSHA and analogous state and local laws, which establish 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 require 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, or MBTA, and analogous state and local laws, which implement 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, or BGEPA, and analogous state and local laws, which prohibit 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 impose liability for discharges of oil into waters of the United States and requires facilities which could be reasonably expected to discharge oil into waters of the United States to maintain and implement appropriate spill contingency plans; and
- National Historic Preservation Act, or NHPA, and analogous state and local laws, which are 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, treat, dispose, gather or 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 these ongoing environmental remediation projects, we spent approximately $990,000 in 2016, approximately $568,000 in 2017 and we have budgeted approximately $620,000 for 2018.

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 2016, the EPA extended its National Enforcement Initiatives, enforcement priorities list, including an initiative related to Energy Extraction Activities, for 2017 through 2019, and the EPA is retaining the Energy Extraction Activities initiative for an additional three years, effective October 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 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 an 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. Settlement negotiations are continuing between the parties. 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 material.

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. This rule has been challenged in federal courts at both the appellate and district court levels. Based on a January 2018 U.S. Supreme Court decision, only the district courts were determined to have jurisdiction to hear the challenges. As a result, stays entered by district courts remain in effect, however, a stay previously issued by the Sixth Circuit is expected to be withdrawn. Accordingly, although the rule is currently stayed in several states pursuant to a district court decision, it could become effective in other states absent additional agency or judicial action. In July 2017 the EPA and the U.S. Army Corps of Engineers published a proposed rule to rescind the 2015 rule. In February 2018, the agencies also published a final rule adding a February 6, 2020 applicability date to the 2015 rule. The final rule adding this applicability date is currently subject to litigation. Although it is unclear how the Corps and the EPA will implement the 2015 rule at this time, the rule may require additional Corps or 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.

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. On April 22, 2016, 175 countries, including the United States, signed the Paris Agreement. The Paris Agreement 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. However, in August of 2017, the United States informed the United Nations of its intent to withdraw from the Paris Agreement. The earliest possible effective withdrawal date from the Paris Agreement is November 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 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, the EPA adopted a final rule, effective August 2, 2016, imposing more stringent controls on methane and volatile organic compounds emissions from oil and gas development, production, and transportation operations under the New Source Performance Standard, or NSPS, program. The EPA is currently reconsidering the rule and has proposed to stay its requirements. However, the rule currently remains in effect. The EPA also finalized a rule regarding the alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements across the oil and gas industry. The BLM also adopted new rules, effective January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. In December 2017, the BLM issued a final rule that temporarily suspends or delays these requirements until January 2019, while BLM considers revising or rescinding these requirements. In addition, many 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's recently finalized NSPS rules or future rules under CAA Section 111(d) could result in the direct regulation of GHGs associated with our operations, including the operations of Rockies Express. 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. 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. In addition, in response to concerns related to climate change, certain investors may divest oil and gas investments. For example, officials in New York state and New York City have announced their intent to divest the state and city pension funds' holdings in fossil fuel companies. Such divestments could adversely impact our costs of and access to capital.

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; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA and has released draft permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where the EPA is the permitting authority. 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 May 2016, the EPA issued final rules that update new source performance standard requirements and that will 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 is currently reconsidering the rule and has proposed to stay its requirements. However, the rule currently remains in effect. The EPA also issued a final rule in June 2016 that prohibits the discharge of hydraulic fracturing wastewater from onshore unconventional oil and gas extraction facilities 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. However, in December 2017, the BLM published a final rule rescinding the 2015 rule. The BLM also adopted new rules effective January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. In December 2017, the BLM issued a final rule that temporarily suspends or delays these requirements until January 2019, while BLM considers revising or rescinding these requirements.

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, and in some cases, may seek to ban hydraulic fracturing entirely. Some state and local authorities have considered or imposed new laws and rules related to hydraulic fracturing, including temporary or permanent bans, additional permit requirements, operational restrictions and chemical disclosure obligations on hydraulic fracturing in certain jurisdictions or in environmentally sensitive areas. 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. On December 13, 2016, the EPA released a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, concluding that there is scientific evidence that hydraulic fracturing activities potentially can impact drinking water resources in the United States under some circumstances.

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, which 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 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, Oklahoma 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. The Oklahoma Corporation Commission, or OCC, has adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes, the implementation of which has involved reductions of injection or shut-ins of disposal wells. The OCC has also released guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to hydraulic fracturing activities. 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 currently contain fuel usage true-up mechanisms. The use of fuel (natural gas, electric and lost and unaccounted for gas) trackers on the Rockies Express Pipeline, the TIGT System, and the Trailblazer Pipeline, while minimizing risk over time, nevertheless leaves the systems exposed 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.

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 to our unitholders.

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 and the indentures governing our senior notes contain certain restrictions which could adversely affect our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

We are dependent upon certain earnings and cash flow generated by our operations in order to meet our debt service obligations. Our revolving credit facility, the indenture governing our 5.50% senior notes due 2024 (the "2024 Notes"), and the indenture governing our 5.50% senior notes due 2028 (the "2028 Notes") contain, and any future financing agreements may contain, operating and financial restrictions and covenants that could restrict our ability to finance future operations or capital needs, or to expand or pursue our business activities, which may, in turn, limit our ability to make cash distributions to our unitholders.

For example, our revolving credit facility limits our ability to, among other things:

- incur or guarantee additional indebtedness;
- 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).

Similarly, the indenture governing the 2024 Notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) pay distributions on equity interests, repurchase equity securities or redeem subordinated securities; (iv) make investments; (v) restrict distributions, loans or other asset transfers from our restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of our properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; and (viii) enter into transactions with affiliates.

In addition, the indenture governing the 2028 Notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (i) create liens to secure indebtedness; (ii) enter into sale-leaseback transactions; and (iii) consolidate with or merge with or into, or sell substantially all of our properties to, another person.

The provisions of our revolving credit facility and the indentures governing our senior notes 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 or the indentures governing our senior notes, including a failure to meet any of the required financial ratios and tests, could result in a default or an event of default that could enable our lenders or the holders of the senior notes to declare the outstanding principal of that indebtedness, together with accrued and unpaid interest, to be immediately due and payable, and in the case of the revolving credit facility, would prohibit our ability to make quarterly distributions. If the payment of our indebtedness is accelerated and we are unable to repay the indebtedness 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 indebtedness 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 25,619,218 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 25,619,218 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 indebtedness levels may limit our flexibility to obtain financing and to pursue other business opportunities.

Our level of indebtedness 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 indebtedness;
- 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 indebtedness 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 our unit price, our ability to issue equity or incur indebtedness for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

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 indebtedness for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Rockies Express has a substantial amount of indebtedness and Rockies Express may not be able to generate a sufficient amount of cash flow to meet its debt service obligations.

As of December 31, 2017 Rockies Express had approximately $2.575 billion of total indebtedness outstanding. In addition, Rockies Express has a revolving credit facility, which will mature on January 31, 2020, with $150 million of additional borrowing capacity available as of December 31, 2017.

The scheduled maturities of Rockies Express' outstanding indebtedness balances as of December 31, 2017 are summarized as follows (in millions):

Year	Scheduled Maturities
2018	$ 550.0
2019	525.0
2020	750.0
Thereafter	750.0

The substantial indebtedness held by Rockies Express could have important consequences. For example, it could:

- make it more difficult for Rockies Express to satisfy its obligations with respect to its indebtedness;
- increase the vulnerability of Rockies Express to general adverse economic and industry conditions;
- limit the ability of Rockies Express to obtain additional financing for future working capital, capital expenditures and other general business purposes;
- require Rockies Express to dedicate a substantial portion of its cash flow from operations to payments on its indebtedness, thereby reducing the availability of cash flow for operations and other purposes;
- limit its flexibility in planning for, or reacting to, changes in its business and the industry in which Rockies Express operates;

- place Rockies Express at a competitive disadvantage compared to its competitors that have less indebtedness; and
- have a material adverse effect if Rockies Express fails to comply with the covenants in the indenture relating to its notes or in the instruments governing its other indebtedness.

The terms of the indentures governing the existing Rockies Express notes do not restrict the amount of additional unsecured indebtedness Rockies Express may incur, and the agreement governing its credit facility permits additional unsecured borrowings. If new indebtedness is added to the current indebtedness levels, these related risks could increase.

Rockies Express' ability to make scheduled payments or to refinance its obligations with respect to its indebtedness will depend on its financial and operating performance, which, in turn, is subject to prevailing economic conditions and to financial, business, and other factors beyond its control. In addition, a significant amount of Rockies Express' revenue in 2017 was generated by long-term contracts that expire in 2019 and Rockies Express may not be able to renew or replace expiring contracts at favorable rates or on a long-term basis, which may result in lower cash flows in periods subsequent to 2019. We cannot assure you that Rockies Express' operating performance, cash flow and capital resources will be sufficient for payment of its indebtedness in the future. In the event that Rockies Express is required to dispose of material assets or restructure its indebtedness to meet its debt service and other obligations, we cannot assure you as to the terms of any such transaction or how soon any such transaction could be completed.

If Rockies Express' cash flow and capital resources are insufficient to fund its debt service obligations, it may be forced to sell material assets, obtain additional capital, including through capital contributions from its members, or restructure its indebtedness. The payment of additional capital contributions by us to Rockies Express to fund such obligations would reduce the amount of cash available to make distributions to our unitholders.

Rockies Express' revolving credit facility contains certain restrictions which could limit its financial flexibility and increase its financing costs.

Rockies Express' revolving credit facility contains restrictive covenants that may prevent it from engaging in various transactions that Rockies Express deems beneficial and that may be beneficial to Rockies Express. The revolving credit facility generally requires Rockies Express to comply with various affirmative and negative covenants, including a limit on the leverage ratio (as defined in the credit agreement) of Rockies Express and restrictions on:

- incurring secured indebtedness;
- entering into mergers, consolidations and sales of assets;
- granting liens;
- entering into transactions with affiliates; and
- making restricted payments.

Instruments governing any future indebtedness at Rockies Express may contain similar or more restrictive provisions. Rockies Express' ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be restricted.

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, surface use agreements 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, surface use agreements 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, surface use agreements 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, surface use agreements 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 in certain instances. To the extent federal eminent domain authority is not available, the availability of eminent domain for future crude oil or natural gas pipeline expansions 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.

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 terminalling of crude oil, the transportation, storage and processing of natural gas, and the transportation, gathering and disposal of water 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 initial public offering, 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 units.

New technologies, 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, including 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 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, wired, 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, consultants, and contractors. 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 reduce these risks by using redundancy for certain critical 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.

Rockies Express is a joint venture and our investment could be adversely affected by our lack of sole decision-making authority.

We and our affiliates do not control Rockies Express through our collective ownership of a 75% membership interest. Under the limited liability company agreement of Rockies Express, as amended, substantially all matters are decided by a vote of 80% of the membership interests, other than certain fundamental decisions that require a vote of 90% of the membership interests. As a result, all of the decisions of the Rockies Express members effectively require unanimous approval of all three members of Rockies Express, including Phillips 66. Thus, our investment in Rockies Express involves risks that are not present when we and our affiliates are able to exercise control over an asset, including the possibility that the unaffiliated third-party member of Rockies Express might become bankrupt, fail to fund its required capital contributions or otherwise attempt to make business decisions with respect to Rockies Express that we do not believe are in its best interest. Moreover, under the Rockies Express limited liability company agreement, we are required to provide certain capital contributions in order to fund expenditures contemplated by Rockies Express' annual budget, and may be required to provide capital contributions under certain circumstances specified in the Rockies Express limited liability company agreement if determined to be reasonably necessary by a vote of Rockies Express' members.

The unaffiliated third-party member of Rockies Express may have economic or other business interests or goals that are inconsistent with our and our affiliates' business interests or goals. Although we generally anticipate that we will agree with Tallgrass Equity on managerial decisions at Rockies Express, we do not have a voting trust or other arrangement in place requiring Tallgrass Equity and us to vote jointly. Plus, the Rockies Express limited liability company agreement expressly permits Rockies Express members (including Tallgrass Equity) to make decisions with respect to their ownership interest without taking into account the interests of Rockies Express or any other member of Rockies Express.

Our membership interest in Rockies Express is subject to a right of first refusal, which may make it more difficult to sell our interest in Rockies Express in the future.

Under the terms of Rockies Express' limited liability company agreement, if any member desires to transfer its membership interest to an unaffiliated third party, each other member first has a right to purchase its proportionate share of the membership interest being sold. If we desire to sell all or any portion of our interest in Rockies Express to an unaffiliated third-party in the future, we will be required to first offer the sale of our membership interest to the other members, who will have 30 days to elect to purchase their proportionate interest before any sale or transfer to a third party may be consummated. This requirement could make it difficult for us to sell our interest in Rockies Express.

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 31.43% 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.

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 may have a fiduciary duty to manage our general partner in a manner that is in the best interests of its owner, Tallgrass Equity. Tallgrass Equity has no duty to us. 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 Equity, TEGP Management, Tallgrass Energy Holdings 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 and 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 Holdings' obligation to offer us certain assets (if Tallgrass Development Holdings decides to sell such assets to a non-affiliate) 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 TEGP Management and may owe fiduciary duties to Tallgrass Energy Holdings and the members of Tallgrass Energy Holdings. Accordingly, these officers will devote significant time to the business of Tallgrass Energy Holdings and TEGP Management.
- 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 Energy Holdings 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 Holdings' 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, 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 Energy Holdings, 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 Holdings' obligation to offer us certain assets (if Tallgrass Development Holdings decides to sell such assets to a non-affiliate) 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 Energy Holdings, 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. For example, Tallgrass Equity recently acquired the 25.01% membership interest in Rockies Express previously owned by Tallgrass Development in connection with the merger of Tallgrass Development into Tallgrass Development Holdings on February 7, 2018. Because this transaction was with an affiliate of Tallgrass Development, the right of first offer under the TEP Omnibus Agreement did not apply, and Tallgrass Development was permitted to transfer that asset to Tallgrass Equity without any duty or obligation to us.

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. 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 and result in less than favorable treatment of us and our common unitholders.

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.

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 indebtedness 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 Equity). Tallgrass Equity currently owns approximately 35% of our outstanding common units.

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

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

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

In order to avoid any material adverse effect on the maximum applicable rates that can be charged to customers by our subsidiaries on assets that are subject to rate regulation by the FERC or an analogous regulatory body, we have adopted certain requirements regarding those investors who may own our common units. Eligible holders are individuals or entities subject to United States federal income taxation on the income generated by us or entities not subject to United States federal income taxation on the income generated by us, so long as all of the entity's owners are subject to such taxation. If a holder of our common units (other than affiliates of our general partner) is not a person who fits the requirements to be an eligible taxable holder, such holder will not be entitled to 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.

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 Equity currently owns approximately 35% of our outstanding common units. 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 cause the transfer of all or a portion of Tallgrass Equity's 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.

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, at times during recent years, the capital markets have limited the availability of capital through traditional issuances of common units. As these periods occur in the future, 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 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 Equity, which owns our general partner, currently holds 25,619,218 common units. In addition, we have agreed to provide our general partner and its affiliates with certain registration rights. For example, 5,619,218 of the common units owned by Tallgrass Equity were registered pursuant to our Form S-3/A (File No. 333-210976) filed with the SEC on May 6, 2016, which became effective May 17, 2016. 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*.

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 such sale. Tallgrass Equity, an affiliate of our general partner, currently owns approximately 35% of our outstanding common units.

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

The holder or holders of a majority of the IDRs, which is currently our general partner, have the right, at any time when there are no subordinated units outstanding and the holders have received incentive distributions at the highest level to which they are entitled (48%) for each of the prior four consecutive fiscal quarters (and the amount of each such distribution did not exceed adjusted operating surplus for each such quarter), to reset the minimum quarterly distribution and the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution"), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. 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 would 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 U.S. 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, from time to time, members of the U.S. Congress propose and consider substantive changes to the U.S. federal income tax laws that affect publicly traded partnerships. We are unable to predict whether any such changes or proposals will be considered 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.

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 21%, 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 U.S. federal income tax purposes there would be a material reduction in our 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, 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.

Our unitholders are required to pay income taxes on their share of our taxable income even if they do not receive any cash distributions from us. A unitholder's share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, transactions in which we engage or changes in law and may be substantially different from any estimate we make in connection with a unit offering.

A unitholder's allocable share of our taxable income will be taxable to it, which may require the unitholder to pay federal income taxes and, in some cases, state and local income taxes, even if the unitholder receives cash distributions from us that are less than the actual tax liability that results from that income or no cash distributions at all.

A unitholder's share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, which may be affected by numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control, and certain transactions in which we might engage. For example, we may engage in transactions that produce substantial taxable income allocations to some or all of our unitholders without a corresponding increase in cash distributions to our unitholders, such as a sale or exchange of assets, the proceeds of which are reinvested in our business or used to reduce our debt, or an actual or deemed satisfaction of our indebtedness for an amount less than the adjusted issue price of the debt. A unitholder's ratio of its share of taxable income to the cash received by it may also be affected by changes in law. For instance, under the recently enacted tax reform law known as the Tax Cuts and Jobs Act, the net interest expense deductions of certain business entities, including us, are limited to 30% of such entity's "adjusted taxable income," which is generally taxable income with certain modifications. If the limit applies, a unitholder's taxable income allocations will be more (or its net loss allocations will be less) than would have been the case absent the limitation.

From time to time, in connection with an offering of our units, we may state an estimate of the ratio of federal taxable income to cash distributions that a purchaser of units in that offering may receive in a given period. These estimates depend in part on factors that are unique to the offering with respect to which the estimate is stated, so the expected ratio applicable to other units will be different, and in many cases less favorable, than these estimates. Moreover, even in the case of units purchased in the offering to which the estimate relates, the estimate may be incorrect, due to the uncertainties described above, challenges by the IRS to tax reporting positions which we adopt, or other factors. The actual ratio of taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units.

If the IRS contests the U.S. 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 U.S. 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 U.S. 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 U.S. 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.

Under the recently enacted Tax Cuts and Jobs Act, if a unitholder sells or otherwise disposes of a common unit, the transferee is required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferee but were not withheld. However, the Department of the Treasury and the IRS have determined that this withholding requirement should not apply to any disposition of a publicly traded interest in a publicly traded partnership (such as us) until regulations or other guidance have been issued clarifying the application of this withholding requirement to dispositions of interests in publicly traded partnerships. Accordingly, while this new withholding requirement does not currently apply to interests in us, there can be no assurance that such requirement will not apply in the future.

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 U.S. 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 U.S. 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 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 U.S. 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 U.S. 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.

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 U.S. 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 tax laws and transactional tax laws such as excise, sales/use, payroll, franchise and ad valorem tax laws. 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. Further, taxing authorities may change their application of existing taxes, so that additional entities or transactions may become subject to an existing tax. 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. In one such audit, Rockies Express has appealed an excise tax assessment on the gross receipts from certain transactions issued by the Ohio Department of Taxation. If the appeal is unsuccessful, Rockies Express may be subject to substantial additional excise taxes in the future, and imposition of such excise taxes could reduce the cash available for distribution to our unitholders.

We have subsidiaries that are treated as corporations for U.S. 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 subsidiaries that are organized as corporations for U.S. federal income tax purposes. Although these subsidiaries have not previously generated any material taxable 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 taxable 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. Treasury regulations provide that income from water delivery services is not qualifying income unless the partnership providing those services also collects, 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, although the IRS may be unwilling or unable to provide a favorable ruling in a timely manner or at all. 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 *"—Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes. If the IRS were to treat us as a corporation for U.S. 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 any 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, we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

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, we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

In the event the IRS makes an audit adjustment to our income tax returns and we do not or cannot shift the liability to our unitholders in accordance with their interests in us during the year under audit, we will generally have the ability to request that the IRS reduce the determined underpayment by reducing the suspended passive loss carryovers of our unitholders (without any compensation from us to such unitholders if we do not seek reimbursement for the taxes we are required to pay from our unitholders and former unitholders), to the extent such underpayment is attributable to a net decrease in passive activity losses allocable to certain partners. Such reduction, if approved by the IRS, will be binding on any affected unitholders.

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 Energy Holdings and its affiliates pay 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*, 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 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, 2017	$ 48.94	$ 41.13	$ 0.9650
September 30, 2017	52.84	44.37	0.9450
June 30, 2017	54.21	45.53	0.9250
March 31, 2017	55.50	46.91	0.8350
December 31, 2016	48.86	42.59	0.8150
September 30, 2016	49.79	43.19	0.7950
June 30, 2016	50.78	35.62	0.7550
March 31, 2016	42.35	25.82	0.7050

Holders

As of February 13, 2018, there were 56 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 13, 2018, 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.

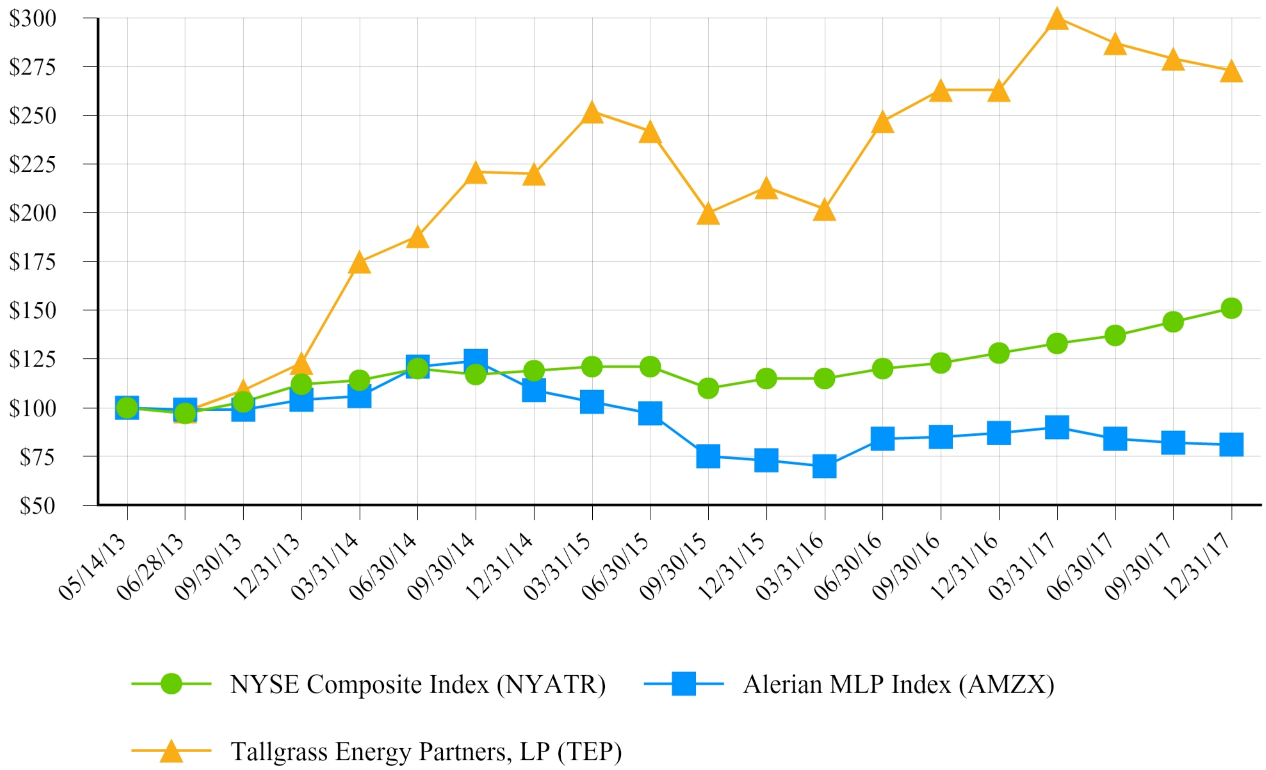
General Partner Interest. Our general partner is currently entitled to approximately 1.13% of all quarterly distributions that we make prior to our liquidation based on its ownership of the general partner interest. As of February 13, 2018, our general partner interest is represented by 834,391 general 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*.

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, 2017. 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 operations of Trailblazer, which was acquired on April 1, 2014, Pony Express, of which TEP acquired a controlling 33.3% membership interest effective September 1, 2014, and Terminals and NatGas, which were acquired effective January 1, 2017. TEP's subsequent acquisitions of an additional 33.3%, 31.3%, and 2% membership interest in Pony Express effective March 1, 2015, January 1, 2016, and February 1, 2018, respectively, represent acquisitions of noncontrolling interests. As a result, financial information for periods prior to those transactions have not been recast to reflect the additional 33.3% and 31.3% membership interests. 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, Pony Express was wholly-owned by TD from November 13, 2012 to August 31, 2014, and Terminals and NatGas were owned by TD from November 13, 2012 to December 31, 2016. 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. 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.

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except per unit amounts)				
Statement of operations data:					
Revenue	$ 655,898	$ 611,662	$ 542,661	$ 377,313	$ 295,873
Operating income	$ 274,087	$ 260,614	$ 207,513	$ 58,970	$ 39,346
Equity in earnings of unconsolidated investments [1]	$ 237,110	$ 54,531	$ 2,759	$ 1,617	$ —
Net income	$ 440,489	$ 274,889	$ 197,171	$ 65,786	$ 12,971
Net income attributable to partners	$ 433,990	$ 270,524	$ 172,903	$ 77,138	$ 15,094
Net income available to common unitholders	$ 286,167	$ 161,064	$ 114,068	$ 61,774	$ 6,991 [2]
Net income per limited partner unit - basic	$ 3.93	$ 2.26	$ 1.95	$ 1.39	$ 0.17 [2]
Net income per limited partner unit - diluted	$ 3.90	$ 2.23	$ 1.91	$ 1.36	$ 0.17 [2]
Balance sheet data (at end of period):					
Property, plant and equipment, net	$ 2,394,337	$ 2,079,232	$ 2,079,567	$ 1,853,081	$ 1,116,806
Unconsolidated investments [1]	$ 909,531	$ 475,625	$ 13,565	$ 15,071	$ 1,255
Total assets	$ 3,977,353	$ 3,102,213	$ 2,634,049	$ 2,476,599	$ 1,631,879
Long-term debt, net	$ 2,146,993	$ 1,407,981	$ 753,000	$ 559,000	$ 135,000
Other:					
Distributions declared per common unit	$ 3.6700	$ 3.0700	$ 2.3400	$ 1.6000	$ 0.7547

(1) For more information see Note 8 – *Investments in Unconsolidated Affiliates*.

(2) 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

As discussed further in Note 2 – *Summary of Significant Accounting Policies, our financial statements for historical periods prior to January 1, 2017 have been recast to reflect the operations of Terminals and NatGas, which were acquired effective January 1, 2017.*

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 in 2013 to own, operate, acquire and develop midstream energy assets in North America. Our operations are 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, Bakken, Marcellus, and Utica shale formations.

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

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

Additional information about our operations and assets is contained in the business overview included in Item 1.—Business under *"Overview"* and *"Our Assets."*

Summary of Results for the Year Ended December 31, 2017

During 2017, we completed the acquisitions of a 100% membership interest in each of Terminals and NatGas, an additional 24.99% membership interest in Rockies Express, a 100% membership interest in DCP Douglas, an aggregate additional 49% membership interest in Deeprock Development, and a 100% membership interest in Outrigger Powder River Operating. In addition, we issued $350 million in aggregate principal amount of 5.50% senior notes due 2024 (the "2024 Notes") and $750 million in aggregate principal amount of 5.50% senior notes due 2028 (the "2028 Notes"), the proceeds of which were used to repay borrowings under our revolving credit facility.

Net income attributable to partners for the year ended December 31, 2017 was $434.0 million, with Adjusted EBITDA and Distributable Cash Flow (each as defined below under "*Non-GAAP Financial Measures*") of $678.0 million and $611.3 million, respectively, compared to net income attributable to partners for the year ended December 31, 2016 of $270.5 million, with Adjusted EBITDA and Distributable Cash Flow of $432.5 million and $408.5 million, respectively. The increase in net income, Adjusted EBITDA, and Distributable Cash Flow was largely driven by our acquisition of an additional 24.99% membership interest in Rockies Express, as discussed further under "Results of Operations" below.

Recent Developments

Distribution Declared

On January 8, 2018, the Board of Directors of our general partner declared a cash distribution for the quarter ended December 31, 2017 of $0.9650 per common unit. The distribution will be paid on February 14, 2018, to unitholders of record on January 31, 2018.

Deeprock North Acquisition and Merger with Deeprock Development

On January 2, 2018, Terminals acquired an approximate 38% membership interest in Deeprock North, LLC ("Deeprock North") from Kinder Morgan Deeprock North Holdco LLC for cash consideration of $19.5 million. Immediately following the acquisition, Deeprock North was merged into Deeprock Development. After the acquisition and merger, Terminals owns an approximately 60% membership interest in the combined entity.

BNN North Dakota Acquisition

In January 2018, Water Solutions acquired a 100% membership interest in Buckhorn Energy Services, LLC and Buckhorn SWD Solutions, LLC (collectively, "BNN North Dakota") for cash consideration of approximately $95.0 million, subject to working capital adjustments. BNN North Dakota owns a produced water gathering and disposal system in the Bakken basin with approximately 133,000 acres under dedication.

Potential Acquisition of Pawnee Terminal

On January 2, 2018, Terminals entered into an agreement to acquire a 51% membership interest in the Pawnee, Colorado crude oil terminal ("Pawnee Terminal") from Zenith Energy Terminals Holdings, LLC for cash consideration of approximately $31 million, subject to working capital adjustments. Terminals expects the transaction to close in the first quarter of 2018, subject to certain closing conditions.

Acquisition of Additional Interest in Pony Express

Effective February 1, 2018, we acquired the remaining 2% membership interest in Pony Express, along with administrative assets consisting primarily of information technology assets, from Tallgrass Development for cash consideration of approximately $60 million, bringing our aggregate membership interest in Pony Express to 100%.

Potential Joint Venture and Sale of TCG

On February 6, 2018, we entered into an agreement with an affiliate of Silver Creek to form Iron Horse Pipeline, a new joint venture pipeline to transport crude oil from the Powder River Basin. In addition to forming the joint venture, we also agreed to sell to Silver Creek our 100% membership interest in TCG, which owns a 50-mile crude oil gathering system in the Powder River Basin. We expect to close the sale of TCG and the formation of the joint venture in February 2018.

Seneca Lateral

On January 31, 2018, Rockies Express experienced an operational disruption on its Seneca Lateral due to a pipe rupture and natural gas release in a rural area in Noble County, Ohio. There were no injuries reported and no evacuations, however, the release required Rockies Express to shut off the flow through the segment. Repairs are underway to return the segment to service as soon as possible and a root cause investigation is ongoing.

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. Crude oil and natural gas prices declined significantly from the second half of 2014 through the first half of 2016 and crude oil experienced significant volatility during that time. However, prices generally stabilized during 2017. Although price declines and volatility could occasionally return to commodity markets at points in the future, we believe long-term prospects for continued domestic 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. spurred by the lower commodity price of feedstock and fuel, 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 and Denver-Julesburg basin, that are likely to be completed and turned into production as commodity prices continue to recover and stabilize.

Current Commodity Environment

Starting in the second half of 2014 and through the first half of 2016, the prices of crude oil, natural gas, and NGLs were extremely volatile and declined significantly. During 2017, price stability appears to have generally been restored to the market, and some of our customers are showing a renewed interest in entering into long-term, fixed obligation contracts. To the extent some of our customers remain concerned about extended unfavorably low prices, it may be due to concerns over excess supply, truncation of current OPEC production cuts and increased mainstream use of alternative sources of energy.

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, the possibility for low commodity prices may result in a lack of available capital for these types of expenditures. To the extent our customers cannot finance these activities, we expect they may be less likely to enter into demand based, long-term firm fee contracts. Low commodity prices 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 may 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 Item 1A.—Risk Factors, "*The Throughput and Deficiency Agreements 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*."

Growth Associated with Acquisitions and Expansion Projects

Growth associated with acquisitions

We believe that we are well-positioned to grow through accretive acquisitions due to our stable financial profile and diverse asset base that presents many logical strategic opportunities. In the past, we heavily relied on acquiring assets from TD's portfolio of midstream assets. Now that TD has divested its entire asset portfolio, our growth through acquisitions will rely almost exclusively on buying assets or businesses from third parties. Third party acquisitions present different risks than those associated with acquiring assets from TD. Sourcing attractive, accretive opportunities and performing diligence on those opportunities requires significantly more time from our employees. Most third-party acquisitions involve competition from other buyers, which generally increases the purchase price. If we are able to execute a third-party transaction, we may encounter challenges when integrating different work cultures and operational systems.

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. For example, in January 2017, Rockies Express placed in service the Rockies Express Zone 3 Capacity Enhancement Project that added an incremental 0.8 Bcf/d of east-to-west capacity within Zone 3 of the Rockies Express Pipeline. During 2017, we announced and are currently executing on the Platteville Extension Project on the Pony Express System and the Cheyenne Connector Pipeline.

Energy Capital Markets and Interest Rates

During the second half of 2015 and into mid-2016, the energy credit markets experienced a material increase in the yields for long-term debt, which caused an issuance of senior unsecured notes to be a less attractive financing option until the third quarter of 2016, when we were able to issue the 2024 Notes. At the same time, the downturn in commodity prices generally limited the availability of capital through traditional public issuances of common units for much of 2016. While the downturn did not change our business plans, including our growth through acquisitions and expansion projects, it did temporarily alter some of our financing strategies. In 2017, we were able to issue an additional $350 million in aggregate principal amount of 2024 Notes and $750 million in aggregate principal amount of 2028 Notes, both at a rate of 5.5%.

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 natural gas transportation and storage capacity, crude oil transportation, storage, gathering and terminalling capacity, NGL transportation capacity, and water transportation, gathering and disposal capacity under firm fee contracts, as well as the volume of natural gas that we gather and 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 deficiency payments received from or utilized by our customers, less cash interest costs, maintenance capital expenditures, distributions to noncontrolling interests in excess of earnings allocated to noncontrolling interests, and certain 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, and are presented net of noncontrolling interest and reimbursements. As discussed in Note 2 – *Summary of Significant Accounting Policies*, prior to December 31, 2015, we received preferred distributions from Pony Express. Effective January 1, 2016 with our acquisition of an additional 31.3% membership interest in Pony Express, distributable cash flow from Pony Express is distributed pro rata based on ownership. Pony Express collects deficiency payments for volumes committed by its customers 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 customers' contractual transportation rights expire or the barrels are physically transported and delivered by 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,		
	2017	2016	2015
		(in thousands)	
Reconciliation of Adjusted EBITDA to Net Income			
Net income attributable to partners	$ 433,990	$ 270,524	$ 172,903
Add:			
Interest expense, net of noncontrolling interest	83,542	40,688	15,517
Depreciation and amortization expense, net of noncontrolling interest	92,455	88,122	77,111
Distributions from unconsolidated investments	306,626	78,568	4,648
Non-cash compensation expense [(1)]	8,660	5,780	5,103
(Gain) loss from disposal of assets, net of noncontrolling interest	(654)	1,849	4,795
Non-cash loss related to derivative instruments, net of noncontrolling interest	226	1,547	—
Loss on extinguishment of debt	—	—	226
Less:			
Equity in earnings of unconsolidated investments	(237,110)	(54,531)	(2,759)
Gain on remeasurement of unconsolidated investment	(9,728)	—	—
Non-cash loss allocated to noncontrolling interest	—	—	(9,377)
Adjusted EBITDA	$ 678,007	$ 432,547	$ 268,167
Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Cash Provided by Operating Activities			
Net cash provided by operating activities	$ 579,061	$ 419,583	$ 303,653
Add:			
Interest expense, net of noncontrolling interest	83,542	40,688	15,517
Other, including changes in operating working capital	15,404	(27,724)	(51,003)
Adjusted EBITDA	$ 678,007	$ 432,547	$ 268,167
Add:			
Deficiency payments received, net	27,182	33,496	16,511
Less:			
Cash interest cost	(79,081)	(37,110)	(13,746)
Maintenance capital expenditures, net	(14,822)	(11,323)	(12,123)
Distributions to noncontrolling interest in excess of earnings	—	—	(22,479)
Cash flow attributable to predecessor operations	—	(9,063)	(15,828)
Distributable Cash Flow	$ 611,286	$ 408,547	$ 220,502

(1) Represents TEP's portion of non-cash compensation expense related to Equity Participation Units, excluding amounts allocated to TD, as discussed in Note 15 – *Equity-Based Compensation.*

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,		
	2017	2016	2015
		(in thousands)	
Reconciliation of Adjusted EBITDA to Operating Income in the Natural Gas Transportation Segment [(1)]			
Operating income	$ 67,434	$ 56,135	$ 48,133
Add:			
Depreciation and amortization expense	19,181	20,976	22,927
Distributions from unconsolidated investment	304,663	75,900	—
Other income, net	1,232	1,723	2,639
Less:			
Non-cash (gain) loss related to derivative instruments	(116)	116	—
Segment Adjusted EBITDA	$ 392,394	$ 154,850	$ 73,699
Reconciliation of Adjusted EBITDA to Operating Income in the Crude Oil Transportation Segment [(1)]			
Operating income	$ 190,170	$ 215,784	$ 159,467
Add:			
Depreciation and amortization expense, net of noncontrolling interest	57,172	52,464	39,359
Less:			
Adjusted EBITDA attributable to noncontrolling interests	(3,804)	(4,288)	(24,245)
Non-cash (gain) loss related to derivative instruments, net of noncontrolling interest	(432)	431	—
Non-cash loss allocated to noncontrolling interest	—	—	(9,377)
Segment Adjusted EBITDA	$ 243,106	$ 264,391	$ 165,204
Reconciliation of Adjusted EBITDA to Operating Income (Loss) in the Gathering, Processing & Terminalling Segment [(1)]			
Operating income (loss)	$ 33,453	$ (903)	$ 7,995
Add:			
Depreciation and amortization expense, net of noncontrolling interest	16,102	14,682	14,825
Non-cash loss (gain) related to derivative instruments	2,659	(291)	—
Distributions from unconsolidated investment	1,963	2,668	4,648
Other income	142	—	—
Less:			
Adjusted EBITDA attributable to noncontrolling interests	(2,695)	(77)	(20)
(Gain) loss from disposal of assets, net of noncontrolling interest	(654)	1,849	4,795
Segment Adjusted EBITDA	$ 50,970	$ 17,928	$ 32,243
Total Segment Adjusted EBITDA	$ 686,470	$ 437,169	$ 271,146
Corporate general and administrative costs	(8,463)	(4,622)	(2,979)
Total Adjusted EBITDA	$ 678,007	$ 432,547	$ 268,167

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

Results of Operations

The following provides a summary of our operating metrics for the periods indicated:

	Year Ended December 31,		
	2017	2016	2015
	(in thousands, except operating data)		
Natural Gas Transportation Segment:			
Gas transportation average firm contracted volumes (MMcf/d) [(1)]	1,711	1,627	1,679
Crude Oil Transportation Segment:			
Crude oil transportation average contracted capacity (Bbls/d)	301,936	295,435	252,374
Crude oil transportation average throughput (Bbls/d)[(2)]	267,734	285,507	236,256
Gathering, Processing & Terminalling Segment:			
Natural gas processing inlet volumes (MMcf/d)	109	103	122
Freshwater average volumes (Bbls/d)	69,139	13,201	14,579
Produced water gathering and disposal average volumes (Bbls/d)	31,511	11,307	7,951

(1) Volumes transported under firm fee contracts, excluding Rockies Express.

(2) Approximate average daily throughput for the year ended December 31, 2015 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.

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

	Year Ended December 31, 2017	2016	2015
	(in thousands, except operating data)		
Revenues:			
Crude oil transportation services	$ 345,733	$ 374,949	$ 300,436
Natural gas transportation services	122,364	119,962	119,895
Sales of natural gas, NGLs, and crude oil	108,503	77,123	82,133
Processing and other revenues	79,298	39,628	40,197
Total Revenues	655,898	611,662	542,661
Operating Costs and Expenses:			
Cost of sales	91,213	71,650	75,285
Cost of transportation services	46,200	47,669	46,840
Operations and maintenance	62,069	55,070	50,823
Depreciation and amortization	90,800	86,247	84,258
General and administrative	63,296	55,102	51,351
Taxes, other than income taxes	28,832	25,400	21,796
Contract termination	—	8,061	—
(Gain) loss on disposal of assets	(599)	1,849	4,795
Total Operating Costs and Expenses	381,811	351,048	335,148
Operating Income	274,087	260,614	207,513
Other Income (Expense):			
Interest expense, net	(83,542)	(40,688)	(15,514)
Unrealized gain (loss) on derivative instrument	1,885	(1,291)	—
Equity in earnings of unconsolidated investments	237,110	54,531	2,759
Gain on remeasurement of unconsolidated investment	9,728	—	—
Other income, net	1,221	1,723	2,413
Total Other Income (Expense)	166,402	14,275	(10,342)
Net income	440,489	274,889	197,171
Net income attributable to noncontrolling interests	(6,499)	(4,365)	(24,268)
Net income attributable to partners	$ 433,990	$ 270,524	$ 172,903
Other Financial Data:			
Adjusted EBITDA [1]	$ 678,007	$ 432,547	$ 268,167

[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.

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Revenues. Total revenues were $655.9 million for the year ended December 31, 2017, compared to $611.7 million for the year ended December 31, 2016, which represents an increase of $44.2 million, or 7%, in total revenues. The overall increase in revenue was largely driven by increased revenues of $72.7 million and $5.9 million in the Gathering, Processing & Terminalling and Natural Gas Transportation segments, respectively, partially offset by decreased revenues of $15.9 million in the Crude Oil Transportation segment, as discussed further below.

Operating costs and expenses. Operating costs and expenses were $381.8 million for the year ended December 31, 2017 compared to $351.0 million for the year ended December 31, 2016, which represents an increase of $30.8 million, or 9%. The overall increase in operating costs and expenses is driven by increased operating costs and expenses of $38.3 million and $9.7 million in the Gathering, Processing & Terminalling and Crude Oil Transportation segments, respectively, partially offset by decreased operating costs and expenses of $11.8 million in the Corporate and Other segment and $5.4 million in the Natural Gas Transportation segment, as discussed further below. The decrease in Corporate and Other expenses was primarily driven by an $18.4 million increase in eliminations of intersegment operating costs and expenses, partially offset by a $6.6 million increase in corporate general and administrative costs primarily due to new equity-based compensation grants issued during the year ended December 31, 2017 as well as payroll taxes associated with the vesting of common units associated with equity-based compensation grants under the general partner's Long-term Incentive Plan.

Interest expense, net. Interest expense of $83.5 million for the year ended December 31, 2017 was primarily composed of interest and fees associated with our revolving credit facility, the 2024 Notes issued on September 1, 2016 and May 16, 2017, and the 2028 Notes issued on September 15, 2017 and December 11, 2017. Interest expense of $40.7 million for the year ended December 31, 2016 was primarily composed of interest and fees associated with our revolving credit facility and the 2024 Notes issued on September 1, 2016. The increase in interest and fees is primarily due to increased borrowings to fund a portion of our acquisitions as discussed further in Note 3 - *Acquisitions*, as well as the higher borrowing rate on the 2024 and 2028 Notes, the proceeds of which were used to repay borrowings under our revolving credit facility.

Unrealized gain (loss) on derivative instrument. Unrealized gain on derivative instrument of $1.9 million and unrealized loss on derivative instrument of $1.3 million for the years ended December 31, 2017 and 2016, respectively, represents the change in fair value of the call option received from TD as part of the acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016. As of February 1, 2017, no common units remained subject to the call option.

Equity in earnings of unconsolidated investments. Equity in earnings of unconsolidated investments was $237.1 million and $54.5 million for the years ended December 31, 2017 and 2016, respectively. Equity in earnings of unconsolidated investments of $237.1 million for the year ended December 31, 2017 primarily reflects our portion of earnings and the amortization of a negative basis difference of $23.2 million associated with our 49.99% membership interest in Rockies Express, as well as $1.5 million of equity in earnings related to our 20% membership interest in Deeprock Development prior to our acquisition of a controlling financial interest in Deeprock Development in July 2017, as discussed in Note 3 - *Acquisitions*. The equity in earnings for the year ended December 31, 2017 includes recognition of our portion of the $150 million gain on settlement of the Ultra litigation as discussed in Note 17 – *Legal and Environmental Matters*. Equity in earnings of unconsolidated investments of $54.5 million for the year ended December 31, 2016 primarily reflects our portion of earnings and the amortization of a negative basis difference of $9.1 million associated with our acquisition of a 25% membership interest in Rockies Express effective May 6, 2016, as well as $2.8 million related to our 20% membership interest in Deeprock Development during the year ended December 31, 2016. The equity in earnings for the year ended December 31, 2016 includes recognition of our portion of the $65 million settlement received by Rockies Express related to the lawsuit between Mineral Management Service, a former unit of the U.S. Department of Interior (collectively "Interior") and Rockies Express as discussed in Note 17 – *Legal and Environmental Matters*. For additional information, see Note 8 – *Investments in Unconsolidated Affiliates*.

Gain on remeasurement of unconsolidated investment. Gain on remeasurement of unconsolidated investment of $9.7 million for the year ended December 31, 2017 was related to the remeasurement to fair value of our existing 20% membership interest in Deeprock Development in connection with our acquisition of a controlling financial interest in Deeprock Development in July 2017. For additional information, see Note 3 – *Acquisitions.*

Other income, net. Other income, net typically includes rental income and income earned from certain customers related to the capital costs we incurred to connect these customers to our system. Other income for the year ended December 31, 2017 was $1.2 million compared to $1.7 million for the year ended December 31, 2016. The decrease in other income was driven by lower income related to reimbursable projects at TIGT due to contract modifications.

Net income attributable to noncontrolling interests. Net income attributable to noncontrolling interests of $6.5 million and $4.4 million for the years ended December 31, 2017 and 2016, respectively, primarily reflects the net income allocated to the 2% noncontrolling interest in Pony Express, as well as $2.7 million allocated to the 31% noncontrolling interest in Deeprock Development subsequent to our acquisition of a controlling financial interest in July 2017.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Revenues. Total revenues were $611.7 million for the year ended December 31, 2016, compared to $542.7 million for the year ended December 31, 2015, which represents an increase of $69.0 million, or 13%, in total revenues. The overall increase in revenue was primarily driven by increased revenues of $76.3 million in the Crude Oil Transportation segment, partially offset by decreased revenues of $2.9 million in the Natural Gas Transportation segment, as discussed further below.

Operating costs and expenses. Operating costs and expenses were $351.0 million for the year ended December 31, 2016 compared to $335.1 million for the year ended December 31, 2015, which represents an increase of $15.9 million, or 5%. The overall increase in operating costs and expenses was primarily driven by increased operating costs and expenses of $20.0 million and $9.0 million in the Crude Oil Transportation and the Gathering, Processing & Terminalling segments, respectively, partially offset by decreased operating costs and expenses of $10.9 million in the Natural Gas Transportation segment, as discussed further below, as well as a $2.2 million decrease in the Corporate and Other segment primarily driven by an $4.5 million increase in eliminations of intersegment operating costs and expenses, partially offset by a $2.3 million increase in corporate general and administrative costs due to increased overhead costs allocated from TD.

Interest expense, net. Interest expense of $40.7 million for the year ended December 31, 2016 was primarily composed of interest and fees associated with our revolving credit facility and the 2024 Notes issued on September 1, 2016. Interest expense of $15.5 million for the year ended December 31, 2015 was primarily composed of interest and fees associated with our 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. The increase in interest and fees is primarily due to increased borrowings under our revolving credit facility to fund a portion of our 2016 and 2015 acquisitions, as discussed further in Note 3 - *Acquisitions*, as well as the higher borrowing rate on the 2024 Notes, the proceeds of which were used to repay borrowings under our revolving credit facility.

Unrealized gain (loss) on derivative instrument. Unrealized loss on derivative instrument of $1.3 million represents the change in fair value of the call option received from TD as part of the acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016.

Equity in earnings of unconsolidated investments. Equity in earnings of unconsolidated investments was $54.5 million and $2.8 million for the years ended December 31, 2016 and 2015, respectively. Equity in earnings of unconsolidated investments of $54.5 million for the year ended December 31, 2016 reflects our portion of earnings and the amortization of a negative basis difference of $9.1 million associated with our acquisition of a 25% membership interest in Rockies Express effective May 6, 2016, as well as $2.8 million related to our 20% membership interest in Deeprock Development. The equity in earnings of Rockies Express for the year ended December 31, 2016 includes recognition of our portion of the $65 million settlement received by Rockies Express related to the lawsuit between Interior and Rockies Express as discussed in Note 17 – *Legal and Environmental Matters*. Equity in earnings of unconsolidated investments of $2.8 million for the year ended December 31, 2015 represents earnings associated with our 20% membership interest in Deeprock Development. For additional information, see Note 8 – *Investments in Unconsolidated Affiliates*.

Other income, net. Other income, net typically includes rental income and income earned from certain customers related to the capital costs we incurred to connect these customers to our system. Other income for the year ended December 31, 2016 was $1.7 million compared to $2.4 million for the year ended December 31, 2015. The decrease in other income was driven by lower income related to reimbursable projects at TIGT due to a contract termination during the year ended December 31, 2016.

Net income attributable to noncontrolling interests. Net income attributable to noncontrolling interests of $4.4 million for the year ended December 31, 2016 primarily reflects the net income allocated to TD's 2% noncontrolling interest in Pony Express. Net income attributable to noncontrolling interest 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.

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

Segment Financial Data – Natural Gas Transportation [1]	Year Ended December 31, 2017	2016	2015
	(in thousands)		
Revenues:			
Natural gas transportation services	$ 129,058	$ 125,603	$ 125,279
Sales of natural gas, NGLs, and crude oil	3,412	3,241	6,346
Processing and other revenues	8,551	6,253	6,363
Total revenues	141,021	135,097	137,988
Operating costs and expenses:			
Cost of sales	2,767	3,804	6,342
Cost of transportation services	2,852	5,051	10,927
Operations and maintenance	28,910	28,458	27,767
Depreciation and amortization	19,180	20,976	22,927
General and administrative	15,385	16,335	17,052
Taxes, other than income taxes	4,493	4,338	4,840
Total operating costs and expenses	73,587	78,962	89,855
Operating income	$ 67,434	$ 56,135	$ 48,133

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

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Revenues. Natural Gas Transportation segment revenues were $141.0 million for the year ended December 31, 2017, compared to $135.1 million for the year ended December 31, 2016, which represents an increase of $5.9 million, or 4%, in segment revenues primarily due to a $3.5 million increase in natural gas transportation services, a $2.3 million increase in other revenue, and a $0.2 million increase in sales of natural gas, NGLs, and crude oil. The $3.5 million increase in natural gas transportation services was driven by increased tariff rates at TIGT, partially offset by a change in the fuel recovery structure, beginning May 1, 2016 as a result of the rate case settlement discussed in Note 16 – *Regulatory Matters*, as well as increased throughput volumes at Trailblazer. The $2.3 million increase in other revenues was primarily attributable to the increased management fee received by NatGas as a result of the Ultra settlement recognized during the year ended December 31, 2017, as discussed in Note 17 – *Legal and Environmental Matters*.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation segment were $73.6 million for the year ended December 31, 2017 compared to $79.0 million for the year ended December 31, 2016, which represents a decrease of $5.4 million, or 7%. The overall decrease in operating costs and expenses was primarily due to a $2.2 million decrease in the cost of transportation services, a $1.8 million decrease in depreciation and amortization, and a $1.0 million decrease in cost of sales. The $2.2 million decrease in the cost of transportation services was driven by lower costs associated with fuel reimbursements as a result of changes to TIGT's fuel recovery structure and the $1.8 million decrease in depreciation and amortization was driven by changes in depreciation rates at TIGT, both as a result of the 2016 rate case settlement discussed above. The $1.0 million decrease in cost of sales was driven by decreased volumes sold as well as a lower of cost and net realizable value inventory adjustment during the year ended December 31, 2016.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Revenues. Natural Gas Transportation segment revenues were $135.1 million for the year ended December 31, 2016, compared to $138.0 million for the year ended December 31, 2015, which represents a decrease of $2.9 million, or 2%, in segment revenues driven by a $3.1 million decrease in the sales of natural gas, NGLs, and crude oil as a result of lower volumes of natural gas sold. The decrease in sales of natural gas, NGLs, and crude oil was partially offset by a $0.3 million increase in natural gas transportation services primarily driven by a $2.3 million increase at TIGT, partially offset by a $1.9 million decrease at Trailblazer due to warmer weather in the first quarter of 2016, resulting in lower volumes transported during the year ended December 31, 2016. The increase in natural gas transportation services revenue at TIGT was primarily driven by increased tariff rates, partially offset by a change in the fuel recovery structure, beginning May 1, 2016 as a result of the rate case settlement discussed in Note 16 – *Regulatory Matters.*

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation segment were $79.0 million for the year ended December 31, 2016 compared to $89.9 million for the year ended December 31, 2015, which represents a decrease of $10.9 million, or 12%. The overall decrease in operating costs and expenses was primarily driven by a $5.9 million decrease in cost of transportation services due to lower costs associated with fuel reimbursements as a result of the change in the fuel recovery structure discussed above, a $2.5 million decrease in cost of sales due to lower volumes of natural gas sold, and a $2.0 million decrease in depreciation and amortization due to lower depreciation rates as of May 1, 2016 as a result of the TIGT rate case settlement.

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

Segment Financial Data – Crude Oil Transportation [(1)]	Year Ended December 31, 2017	2016	2015
		(in thousands)	
Revenues:			
Crude oil transportation services	$ 353,395	$ 374,949	$ 300,436
Sales of natural gas, NGLs, and crude oil	11,179	5,554	3,791
Total revenues	364,574	380,503	304,227
Operating costs and expenses:			
Cost of sales	9,680	4,728	4,257
Cost of transportation services	57,284	55,519	47,367
Operations and maintenance	11,838	13,075	8,795
Depreciation and amortization	52,364	51,362	47,168
General and administrative	20,906	20,650	20,620
Taxes, other than income taxes	22,332	19,385	16,553
Total operating costs and expenses	174,404	164,719	144,760
Operating income	$ 190,170	$ 215,784	$ 159,467

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

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Revenues. Crude Oil Transportation segment revenues were $364.6 million for the year ended December 31, 2017, compared to $380.5 million for the year ended December 31, 2016, which represents a decrease of $15.9 million, or 4%, in segment revenues driven by a $21.6 million decrease in crude oil transportation services, primarily due to a $27.1 million increase in shipper deficiency payments that are not recognized in revenue and a $9.9 million decrease in the incremental barrels delivered during the year ended December 31, 2017 compared to the year ended December 31, 2016, partially offset by a $7.8 million increase in committed barrels shipped and a $7.0 million increase in walk-up barrels shipped. The decrease in crude oil transportation services was partially offset by a $5.6 million increase in sales of natural gas, NGLs, and crude oil primarily due to increased volumes of crude oil sold during the year ended December 31, 2017 compared to the year ended December 31, 2016.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation segment were $174.4 million for the year ended December 31, 2017 compared to $164.7 million for the year ended December 31, 2016, which represents an increase of $9.7 million, or 6%. The overall increase in operating costs and expenses was primarily driven by a $5.0 million increase in cost of sales primarily due to increased volumes of crude oil sold during the year ended December 31, 2017, a $2.9 million increase in taxes, other than income taxes, driven by assets placed in service throughout 2016, and a $1.8 million increase in cost of transportation services as a result of amendments to the Deeprock Terminal lease agreement, resulting in the non-cash write off of upfront payments in the fourth quarter of 2017, partially offset by lower lease payments during the third and fourth quarters of 2017. The increased cost of transportation services during the year ended December 31, 2017 as a result of the Deeprock Terminal lease was partially offset by higher electric costs as a result of pressure restrictions during the year ended December 31, 2016. The cost increases during the year ended December 31, 2017 were partially offset by a $1.2 million decrease in operations and maintenance costs due to the timing of pipeline integrity work.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Revenues. Crude Oil Transportation segment revenues were $380.5 million for the year ended December 31, 2016 compared to $304.2 million for the year ended December 31, 2015 which represents an increase of $76.3 million, or 25%, in segment revenues due to a $74.5 million increase in crude oil transportation services revenue and a $1.8 million increase in sales of crude oil primarily due to increased volumes sold during the year ended December 31, 2016. The increase in crude oil transportation services was primarily driven by a $42.6 million increase in revenue from a full period of operations on the lateral in Northeast Colorado, which began commercial operations during the second quarter of 2015, a $19.6 million increase related to the activation of one of our joint tariffs in the second quarter of 2015, and lower revenue of $9.8 million during the year ended December 31, 2015 due to a force majeure at one of our joint tariff partners.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation segment were $164.7 million for the year ended December 31, 2016 compared to $144.8 million for the year ended December 31, 2015 which represents an increase of $20.0 million, or 14%. The overall increase in operating costs and expenses was primarily driven by an $8.2 million increase in cost of transportation services, primarily due to $4.2 million associated with drag-reduction agents and higher electrical costs at pump stations associated with increased transportation volumes, and increases of $4.3 million, $4.2 million, and $2.8 million in operations and maintenance costs, depreciation and amortization, and taxes, other than income taxes, respectively, all primarily driven by the costs associated with a full period of operations on the lateral in Northeast Colorado.

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

	Year Ended December 31,		
Segment Financial Data – Gathering, Processing & Terminalling [(1)]	2017	2016	2015
	(in thousands)		
Revenues:			
Sales of natural gas, NGLs, and crude oil	$ 93,998	$ 68,698	$ 71,996
Processing and other revenues	92,213	44,835	41,391
Total revenues	186,211	113,533	113,387
Operating costs and expenses:			
Cost of sales	80,088	63,746	64,686
Cost of transportation services	20,650	3,942	1,487
Operations and maintenance	21,321	13,537	14,261
Depreciation and amortization	19,256	13,909	14,163
General and administrative	10,035	7,715	5,597
Taxes, other than income taxes	2,007	1,677	403
Contract termination	—	8,061	—
(Gain) loss on disposal of assets	(599)	1,849	4,795
Total operating costs and expenses	152,758	114,436	105,392
Operating income (loss)	$ 33,453	$ (903)	$ 7,995

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

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Revenues. Gathering, Processing & Terminalling segment revenues were $186.2 million for the year ended December 31, 2017, compared to $113.5 million for the year ended December 31, 2016, which represents a $72.7 million, or 64%, increase in segment revenues. The increase in segment revenues was primarily due to a $47.4 million increase in processing and other revenues and a $25.3 million increase in sales of natural gas, NGLs, and crude oil. The increase in processing and other revenues was driven by (i) increased water business services revenue of $29.8 million as a result of increased fresh water supply and produced water disposal volumes; (ii) increased terminalling services revenue of $11.0 million driven by the acquisition of a controlling interest in and subsequent consolidation of Deeprock Development in July 2017; and (iii) increased fee income of $6.1 million driven by the acquisition of the Douglas Gathering System in May 2017. The increase in sales of natural gas, NGLs, and crude oil was driven by a 36% increase in NGL prices and sales of residue gas from the Douglas Gathering System, partially offset by lower volumes of NGLs sold during the year ended December 31, 2017 as a result of take in kind elections in effect for parts of 2017 under two major processing agreements.

Operating costs and expenses. Operating costs and expenses in the Gathering, Processing & Terminalling segment were $152.8 million for the year ended December 31, 2017 compared to $114.4 million for the year ended December 31, 2016, which represents an increase of $38.3 million, or 33%. The increase in operating costs and expenses was driven by (i) a $16.7 million increase in cost of transportation services primarily driven by increased volumes in water business services as discussed above and crude oil transportation fees paid by Stanchion during the year ended December 31, 2017; (ii) a $16.3 million increase in cost of sales primarily driven by higher producer settlements and higher NGL sales attributable to the acquisition of the Douglas Gathering System in 2017 as discussed above; and (iii) increases of $7.8 million, $5.3 million, and $2.3 million in operations and maintenance costs, depreciation and amortization, and general and administrative costs, respectively, all primarily driven by the 2017 acquisitions of the Douglas Gathering System, the PRB Crude System, and Deeprock Development. These increases were partially offset by a $8.1 million contract termination fee as a result of the buyout of an operating agreement at the Sterling Terminal during the year ended December 31, 2016 and a $2.4 million decrease in (gain) loss on disposal of assets primarily driven by a gain on disposal of assets from insurance proceeds received during the year ended December 31, 2017 related to assets destroyed by a fire caused by a lightning strike during the year ended December 31, 2016.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Revenues. Gathering, Processing & Terminalling segment revenues were $113.5 million for the year ended December 31, 2016, compared to $113.4 million for the year ended December 31, 2015, which represents a $0.1 million increase in segment revenues. The increase in segment revenues was primarily due to a $3.4 million increase in processing and other revenues driven by increased terminalling services revenue of $4.4 million, resulting from a full year of operations at the Sterling Terminal, and increased water business services revenue of $4.0 million primarily attributable to the Western and West Texas asset acquisitions, partially offset by lower processing fees of $4.9 million due to decreased volumes processed. The increase in processing and other revenues was partially offset by a $3.3 million decrease in the sales of natural gas, NGLs, and crude oil driven by lower NGL and natural gas sales due to lower volumes processed, partially offset by increased NGL prices.

Operating costs and expenses. Operating costs and expenses in the Gathering, Processing & Terminalling segment were $114.4 million for the year ended December 31, 2016 compared to $105.4 million for the year ended December 31, 2015, which represents an increase of $9.0 million, or 9%. The increase in operating costs and expenses was driven by (i) an $8.1 million contract termination fee during the year ended December 31, 2016 as discussed above; (ii) a $2.5 million increase in cost of transportation services due to costs associated with Western, which was acquired on December 16, 2015; (iii) a $2.1 million increase in general and administrative costs due to increased costs allocated to Water Solutions as a result of increased operating income related to our acquisitions of Western and West Texas; and (iv) a $1.3 million increase in taxes, other than income taxes due to higher property tax estimates for 2016 as a result of the Western acquisition and the Sterling Terminal which was placed in service during 2015. These increases were partially offset by (i) a $2.9 million decrease in (gain) loss on disposal of assets as a result of the $1.8 million loss on assets destroyed by fire as a result of a lightning strike during the year ended December 31, 2016, compared to a $4.8 million non-cash loss recognized on the sale of compressor and other assets in 2015; (ii) a $0.9 million decrease in cost of sales driven by decreased NGL volumes processed as discussed above; (iii) a $0.7 million decrease in operations and maintenance costs due to less downtime for plant maintenance activities during the year ended December 31, 2016 compared to the year ended December 31, 2015, partially offset by higher costs associated with the Western and West Texas assets acquired; and (iv) a $0.3 million decrease in depreciation and amortization driven by an intangible asset becoming fully amortized as of December 31, 2015, partially offset by increased depreciation related to the new NGL transportation line.

Liquidity and Capital Resources Overview

Our primary sources of liquidity for the year ended December 31, 2017 were proceeds from the issuance of long-term debt, borrowings under our revolving credit facility, cash generated from operations, and proceeds from the issuance of common units. 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. For additional information regarding our revolving credit facility and senior unsecured notes, see Note 10 - *Long-term Debt*. For additional information regarding our equity transactions, see Note 11 - *Partnership Equity and Distributions.*

Our total liquidity as of December 31, 2017 and 2016 was as follows:

	December 31, 2017	December 31, 2016
	(in thousands)	
Cash on hand	$ 1,809	$ 1,873
Total capacity under the revolving credit facility	1,750,000	1,750,000
Less: Outstanding borrowings under the revolving credit facility [1]	(661,000)	(1,015,000)
Less: Letters of credit issued under the revolving credit facility	(94)	—
Available capacity under the revolving credit facility	1,088,906	735,000
Total liquidity	$ 1,090,715	$ 736,873

(1) As of February 12, 2018, outstanding borrowings under our revolving credit facility were approximately $0.9 billion.

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, accounts payable and deferred revenue. We manage our working capital needs through borrowings and repayments of borrowings under our revolving credit facility. 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 that we buy and sell in the normal course of business can also impact the timing of changes in accounts receivable and accounts payable. Factors impacting deferred revenue include the volume of barrels transported, the amount of deficiency payments received, and the volume of prior deficiencies utilized during the period.

As of December 31, 2017, we had a working capital deficit of $102.4 million compared to a working capital deficit of $38.1 million at December 31, 2016, which represents an increase in the working capital deficit of $64.4 million. The overall increase in the working capital deficit was primarily attributable to changes in the following components:

- an increase in accounts payable of $74.8 million primarily due to crude oil purchases at Stanchion, as well as increased expansion capital accruals at Pony Express and Terminals, and increased settlement volumes at TMID as a result of the Douglas Gathering acquisition;
- an increase in deferred revenue of $27.7 million primarily from deficiency payments collected by Pony Express;
- an increase in accrued liabilities of $19.0 million primarily due to an increase in interest accrued at December 31, 2017 compared to December 31, 2016 due to increased borrowings and higher interest rates on the 2024 and 2028 Notes issued during 2017 compared to borrowings under the revolving credit facility; and
- a decrease in derivative assets at fair value of $11.0 million as we exercised the remainder of the call option granted by TD.

These working capital decreases were partially offset by:

- an increase in accounts receivable of $60.4 million primarily due to crude oil sales at Stanchion; and

- an increase in inventories of $8.5 million primarily due to crude oil purchases at Stanchion.

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,		
	2017	2016	2015
		(in thousands)	
Net cash provided by (used in):			
Operating activities	$ 579,061	$ 419,583	$ 303,653
Investing activities	$ (898,541)	$ (595,539)	$ (899,432)
Financing activities	$ 319,416	$ 176,218	$ 596,523

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Operating Activities. Cash flows provided by operating activities were $579.1 million and $419.6 million for the years ended December 31, 2017 and 2016, respectively. The increase in net cash flows provided by operating activities of $159.5 million was primarily driven by a $182.7 million increase in distributions received from Rockies Express as a result of the Ultra settlement received in July 2017 as well as our increased membership interest during the year ended December 31, 2017.

Investing Activities. Cash flows used in investing activities were $898.5 million for the year ended December 31, 2017, primarily driven by:

- cash outflows of $400.0 million for the acquisition of an additional 24.99% membership interest in Rockies Express;
- capital expenditures of $145.1 million, primarily due to spending on an additional freshwater connection at Water Solutions, a connection to a refinery complex on the Pony Express System, a 55-mile extension on the Pony Express system, and remediation digs on the Pony Express System as discussed in Note 17 – *Legal and Environmental Matters*;
- cash outflows of $140.0 million for the acquisition of Terminals and NatGas;
- cash outflows of $128.5 million for the acquisition of the Douglas Gathering System;
- cash outflows of $57.2 million for the acquisition of an additional 40% membership interest in Deeprock Development;
- contributions to unconsolidated investments in the amount of $45.9 million, primarily to fund remaining costs associated with the Zone 3 Capacity Enhancement project at Rockies Express; and
- cash outflows of $36.0 million for the acquisition of the PRB Crude System.

These cash outflows were partially offset by $69.4 million of distributions received from Rockies Express in excess of cumulative earnings recognized.

Cash flows used in investing activities were $595.5 million for the year ended December 31, 2016, primarily driven by:

- cash outflows of $436.0 million for the acquisition of a 25% membership interest in Rockies Express;
- capital expenditures of $84.5 million, primarily due to post in-service spending on Pony Express System projects, the Pipeline Integrity Management Program at Trailblazer, and costs associated with construction of the Buckingham Terminal;
- cash outflows of $49.1 million for a portion of the acquisition of an additional 31.3% membership interest in Pony Express, the remainder of which is classified as a financing activity as discussed below; and
- contributions to unconsolidated investments in the amount of $50.1 million, primarily to fund costs associated with the Zone 3 Capacity Enhancement project at Rockies Express.

These cash outflows were partially offset by $24.1 million of distributions received from Rockies Express in excess of cumulative earnings recognized.

Financing Activities. Cash flows provided by financing activities were $319.4 million for the year ended December 31, 2017, primarily driven by:

- proceeds from the issuance of $1.1 billion in aggregate principal amount of 2024 and 2028 Notes; and
- net cash proceeds of $112.4 million from the issuance of 2,341,061 common units under our Equity Distribution Agreements.

These financing cash inflows were partially offset by cash outflows of:

- distributions to unitholders of $392.9 million;
- net repayments under the revolving credit facility of $354.0 million;
- $72.4 million for the exercise of the remainder of the call option granted by TD covering 1,703,094 common units;
- $35.3 million for the 736,262 common units repurchased from TD; and
- deferred financing costs of $22.3 million from the issuance of the 2024 and 2028 Notes and the amendment to TEP's revolving credit facility.

Cash flows provided by financing activities were $176.2 million for the year ended December 31, 2016, primarily driven by:

- proceeds from the issuance of $400.0 million in aggregate principal amount of 2024 Notes;
- net cash proceeds of $337.7 million from the issuance of 7,696,708 common units under the Equity Distribution Agreements;
- net borrowings under the revolving credit facility of $262.0 million;
- net cash proceeds of $90.0 million from the issuance of 2,416,987 common units representing limited partnership interests in a private placement transaction; and
- contributions from TD of $17.9 million, which consisted of contributions from TD to TEP in order to 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, as discussed further in Note 17 – *Legal and Environmental Matters.*

These financing cash inflows were partially offset by cash outflows of:

- $425.9 million for the portion of the acquisition of an additional 31.3% membership interest in Pony Express which exceeds the cumulative capital spending on the underlying assets acquired;
- distributions to unitholders of $292.8 million; and
- $204.6 million for the partial exercise of the call option granted by TD covering 4,814,906 common units.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Operating Activities. Cash flows provided by operating activities were $419.6 million and $303.7 million for the years ended December 31, 2016 and 2015, respectively. The increase in net cash flows provided by operating activities of $115.9 million was primarily driven by the increase in operating results as discussed above, $51.8 million of distributions received from Rockies Express, and a net increase in cash inflows from changes in working capital, primarily driven by a $18.8 million increase in net cash inflows from accounts receivable due to collection of receivables during the year ended December 31, 2016 associated primarily with an increase in incremental barrels shipped at Pony Express, and a $13.2 million increase in deferred revenue associated primarily with deficiency payments collected by Pony Express during the year ended December 31, 2016.

Investing Activities. Cash flows used in investing activities were $595.5 million for the year ended December 31, 2016. Investing cash outflows for the year ended December 31, 2016 were primarily driven by 2016 acquisitions, capital expenditures, and contributions to Rockies Express, as discussed above.

Cash flows used in investing activities were $899.4 million for the year ended December 31, 2015, primarily driven by:

- the cash outflow of $700.0 million for the acquisition of an additional 33.3% membership interest in Pony Express, which allowed TD to continue funding the pipeline construction at Pony Express;
- capital expenditures of $120.7 million, primarily due to construction of the Pony Express System, including the lateral in Northeast Colorado, and costs associated with construction of the Sterling Terminal; and
- the cash outflow of $75.0 million for the acquisition of Western.

Financing Activities. Cash flows provided by financing activities were $176.2 million for the year ended December 31, 2016, primarily driven by proceeds from the issuance of the 2024 Notes, issuance of common units, net borrowings under the revolving credit facility, and contributions from TD, partially offset by the portion of the acquisition of the additional 31.3% membership interest in Pony Express which exceeds the cumulative capital spending on the underlying assets acquired, distributions to unitholders, and the partial exercise of the call option granted by TD as discussed above.

Cash flows provided by financing activities were $596.5 million for the year ended December 31, 2015, primarily driven by:

- net cash proceeds of $554.1 million from the issuance of 11,200,000 common units in a public offering and 65,744 common units issued under the Equity Distribution Agreements; and
- net borrowings under the revolving credit facility of $194.0 million.

These financing cash inflows were partially offset by cash outflows of:

- distributions to unitholders of $161.8 million; and
- distributions to noncontrolling interests of $25.1 million, primarily driven by distributions to TD from Pony Express.

Distributions

We do not have a legal obligation to pay distributions except as provided in our partnership agreement. A distribution of $0.9650 per unit, or $111.0 million in the aggregate, for the three months ended December 31, 2017 was announced on January 8, 2018 and will be paid on February 14, 2018 to unitholders of record on January 31, 2018. As of February 13, 2018, we had a total of 74,034,144 common and general partner units outstanding, which equates to an aggregate minimum distribution of approximately $21.3 million per quarter and approximately $85.1 million per year. We intend to continue to pay quarterly distributions at or above the amount of the minimum quarterly distribution, 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 we expect will 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 $238 million for expansion capital projects and approximately $24 million for maintenance capital expenditures in 2018.

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,		
	2017	2016	2015
		(in thousands)	
Maintenance capital expenditures	$ 14,822	$ 11,323	$ 12,123
Expansion capital expenditures	135,604	44,348	72,190
Total capital expenditures incurred	$ 150,426	$ 55,671	$ 84,313

Capital expenditures incurred represent capital expenditures paid and accrued during the period. Capital expenditures are presented net of noncontrolling interest, and contributions and reimbursements received. The increase in maintenance capital expenditures to $14.8 million for the year ended December 31, 2017 from $11.3 million for the year ended December 31, 2016 is primarily driven by increased expenditures in the Crude Oil Transportation and Gathering, Processing & Terminalling 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 increase in expansion capital expenditures to $135.6 million for the year ended December 31, 2017 from $44.3

million for the year ended December 31, 2016 is primarily driven by increased expansion capital expenditures in the Gathering, Processing & Terminalling and Crude Oil Transportation segments. Expansion capital expenditures for the year ended December 31, 2017 consisted primarily of spending on an additional freshwater connection at Water Solutions, construction of the Grasslands Terminal and the Natoma Terminal, a connection to a third-party refinery complex on the Pony Express System and a 55-mile extension on the Pony Express system. Expansion capital expenditures of $44.3 million for the year ended December 31, 2016 consisted primarily of post in-service spending on Pony Express System projects and costs associated with construction of the Buckingham Terminal.

The decrease in maintenance capital expenditures to $11.3 million for the year ended December 31, 2016 from $12.1 million for the year ended December 31, 2015 is primarily driven by decreased maintenance capital expenditures in the Gathering, Processing & Terminalling segment. The decrease in expansion capital expenditures to $44.3 million for the year ended December 31, 2016 from $72.2 million for the year ended December 31, 2015 is primarily driven by decreased expansion capital expenditures in the Gathering, Processing & Terminalling segment. Expansion capital expenditures of $44.3 million for the year ended December 31, 2016 consisted primarily of post in-service spending on Pony Express System projects and costs associated with construction of the Buckingham Terminal. Expansion capital expenditures of $72.2 million for the year ended December 31, 2015 consisted primarily of costs associated with construction of the Sterling Terminal and spending on the NGL pipeline in Northeast Colorado. During the year ended December 31, 2015, substantially all the expansion capital expenditures related to Pony Express System projects were funded by TD.

During the year ended December 31, 2017, we acquired a new unconsolidated affiliate, BNN Colorado Water, LLC ("BNN Colorado") for approximately $7.0 million. In connection with the investment in BNN Colorado, we have made commitments to fund the remaining construction of the pipeline system, estimated at $3.8 million as of December 31, 2017. In addition, we invested cash in unconsolidated affiliates, including Rockies Express, BNN Colorado, and Deeprock Development, of $45.9 million, $50.1 million, and $0.4 million during the years ended December 31, 2017, 2016, and 2015, respectively, to fund our share of capital projects. We have also committed to Rockies Express to fund the repayment of Rockies Express' $550 million 6.85% senior notes due July 15, 2018, in proportion to our 49.99% membership interest, which we intend to fund through borrowings under our revolving credit facility.

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 revolving credit facility, 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, 2017:

	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)]	$ 2,161,000	$ —	$ —	$ 661,000	$ 1,500,000
Interest on debt obligations [(2)]	802,025	107,629	215,327	200,631	278,438
Operating lease and service contract obligations [(3)]	2,383	506	945	464	468
Land site lease and right-of-way [(4)]	7,923	720	1,820	1,457	3,926
Other purchase commitments [(5)]	23,594	19,345	4,161	40	48
Total	$ 2,996,925	$ 128,200	$ 222,253	$ 863,592	$ 1,782,880

(1) Debt obligations at December 31, 2017 consisted of borrowings under the revolving credit facility and the 2024 and 2028 Notes. For additional information, see Note 10 – *Long-term Debt*.

(2) Interest on debt obligations is estimated using current borrowings and interest rates as of December 31, 2017. For additional information, see Note 10 – *Long-term Debt*.

(3) Operating leases and service contracts consist of leases for office space and equipment. For additional information, see Note 12 – *Commitments & Contingent Liabilities*.

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

(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 Tallgrass Energy Holdings 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 Tallgrass Energy Holdings and its affiliates, 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.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Our significant accounting policies and the anticipated impact of recently issued accounting standards are described in Note 2 – *Summary of Significant Accounting Policies*. 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 indicate 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, 2017. 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 2017 using the methodology described herein, and determined there was no impairment.
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. See Item 7A.—Quantitative and Qualitative Disclosures About Market Risk for details regarding the impact of potential changes in the commodity forward price curves on our derivative instruments at December 31, 2017.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Prior to our acquisition of the Douglas Gathering System on June 5, 2017, approximately 99% of our reserved natural gas processing capacity was subject to firm or volumetric fee contracts, with the majority of fee revenue based on the volumes actually processed. With our acquisition of the Douglas Gathering System, the largest existing firm fee contract was terminated because the counterparty to this contract, DCP Douglas, LLC, became our indirect wholly-owned subsidiary. In addition, we acquired a number of commodity sensitive gathering and processing contracts such as percent of proceeds or keep whole processing contracts in the acquisition. During the year ended December 31, 2017, approximately 17%, 53%, and 30% of TMID's Adjusted EBITDA came from firm fee, volumetric fee, and commodity sensitive contracts, respectively. 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.

The following table summarizes the percentage of our Adjusted EBITDA at each reportable segment by contract type for the year ended December 31, 2017:

	Natural Gas Transportation	Crude Oil Transportation	Gathering, Processing & Terminalling	Corporate & Other	Consolidated
Firm fee	55%	35%	5%	— %	95%
Volumetric fee	<1%	1%	2%	— %	3%
Commodity exposed	<1%	<1%	1%	— %	1%
Other	2%	—%	—%	(1)%	1%
Total	57%	36%	8%	(1)%	100%

Historically, we have had a limited amount of direct commodity price exposure related to natural gas collected for electrical compression costs and lost and unaccounted for gas on the TIGT System. Accordingly, we have historically entered into derivative contracts with third parties for a substantial majority of the natural gas we expected to collect for the purpose of hedging our commodity price exposures. In 2016, we also entered into long natural gas swaps covering a portion of the natural gas that TMID expected to purchase in 2017. In addition, 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 and Terminals. During 2016, we began entering into derivative contracts for the sale of crude oil inventory. During 2017, Stanchion began to transact in crude oil and enter into financial derivative contracts in connection with these transactions.

We measure the risk of price changes in our crude oil and natural gas derivatives 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 primarily 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 commodity prices.

The following table summarizes our commodity derivatives and the change in fair value that would be expected from a 10% price increase or decrease as of December 31, 2017, assuming a parallel shift in the forward curve through the end of 2017:

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
		(in thousands)	
Crude oil derivative contracts [(1)]	$ (2,368)	$ (2,151)	$ 2,151

(1) Represents the forward sale of 356,000 barrels of crude oil by our Gathering, Processing & Terminalling segment which will settle throughout the first quarter of 2018.

Interest Rate Risk

As of December 31, 2017, we have issued $750 million of 2024 Notes and $750 million of 2028 Notes. In addition, we have a $1.75 billion revolving credit facility with borrowings of $661.0 million. 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. The applicable margin ranges from 0.50% to 1.50% for base rate borrowings and 1.50% to 2.50% for reserve adjusted Eurodollar rate borrowings, based upon our total leverage ratio.

We do not currently hedge the interest rate risk on our borrowings under the revolving 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 outstanding debt under our revolving credit facility as of December 31, 2017.

Credit Risk

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

A substantial majority of our revenue is produced under long-term firm fee contracts with high-quality customers. The customer base we currently serve under these contracts generally has a strong credit profile, with a majority of our revenues derived from customers who have BB+ or Ba1 and better credit ratings or are part of corporate families with such credit ratings as of December 31, 2017.

We also have indirect credit risk exposure with respect to our investment in Rockies Express. See Item 1A.—Risk Factors for additional information.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Tallgrass MLP, GP, LLP, the general partner of Tallgrass Energy Partners, LP and the unit holders of Tallgrass Energy Partners, LP

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Tallgrass Energy Partners, LP and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of income, equity and cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016**,** and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 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, 2017 , based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Partnership's management is responsible for these consolidated 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 the Partnership's consolidated financial statements and on the Partnership's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

As described in Management's Report on Internal Control over Financial Reporting, management has excluded Terminals, the Douglas Gathering System, and Deeprock Development from its assessment of internal control over financial reporting as of December 31, 2017 because they were acquired by the Partnership during 2017. We have also excluded Terminals, the Douglas Gathering System, and Deeprock Development from our audit of internal control over financial reporting. Terminals and the Douglas Gathering System are wholly-owned subsidiaries and Deeprock Development is a 69% owned consolidated subsidiary whose total assets and total revenues excluded from management's assessment and our audit of internal control over financial reporting represent 11% and 5%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2017.

Definition and Limitations of Internal Control over Financial Reporting

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.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 13, 2018

We have served as the Partnership's auditor since 2012.

TALLGRASS ENERGY PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,809	$ 1,873
Accounts receivable, net	119,955	59,536
Gas imbalances	1,990	1,597
Inventories	21,609	13,093
Derivative assets	—	10,967
Prepayments and other current assets	11,175	7,628
Total Current Assets	156,538	94,694
Property, plant and equipment, net	2,394,337	2,079,232
Goodwill	404,838	343,288
Intangible assets, net	97,731	93,522
Unconsolidated investments	909,531	475,625
Deferred financing costs, net	11,684	4,815
Deferred charges and other assets	2,694	11,037
Total Assets	$ 3,977,353	$ 3,102,213
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts payable	$ 98,882	$ 24,122
Accounts payable to related parties	5,461	5,935
Gas imbalances	1,663	1,239
Derivative liabilities	2,368	556
Accrued taxes	19,272	16,996
Accrued liabilities	35,659	16,702
Deferred revenue	88,471	60,757
Other current liabilities	7,171	6,446
Total Current Liabilities	258,947	132,753
Long-term debt, net	2,146,993	1,407,981
Other long-term liabilities and deferred credits	18,965	7,063
Total Long-term Liabilities	2,165,958	1,415,044
Commitments and Contingencies		
Equity:		
Predecessor Equity	—	82,295
Limited partners (73,199,753 and 72,485,954 common units issued and outstanding at December 31, 2017 and 2016, respectively)	2,109,316	2,070,495
General partner (834,391 units issued and outstanding at December 31, 2017 and 2016)	(625,537)	(632,339)
Total Partners' Equity	1,483,779	1,520,451
Noncontrolling interests	68,669	33,965
Total Equity	1,552,448	1,554,416
Total Liabilities and Equity	$ 3,977,353	$ 3,102,213

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

TALLGRASS ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2017	2016	2015
	(in thousands, except per unit amounts)		
Revenues:			
Crude oil transportation services	$ 345,733	$ 374,949	$ 300,436
Natural gas transportation services	122,364	119,962	119,895
Sales of natural gas, NGLs, and crude oil	108,503	77,123	82,133
Processing and other revenues	79,298	39,628	40,197
Total Revenues	655,898	611,662	542,661
Operating Costs and Expenses:			
Cost of sales	91,213	71,650	75,285
Cost of transportation services	46,200	47,669	46,840
Operations and maintenance	62,069	55,070	50,823
Depreciation and amortization	90,800	86,247	84,258
General and administrative	63,296	55,102	51,351
Taxes, other than income taxes	28,832	25,400	21,796
Contract termination	—	8,061	—
(Gain) loss on disposal of assets	(599)	1,849	4,795
Total Operating Costs and Expenses	381,811	351,048	335,148
Operating Income	274,087	260,614	207,513
Other Income (Expense):			
Interest expense, net	(83,542)	(40,688)	(15,514)
Unrealized gain (loss) on derivative instrument	1,885	(1,291)	—
Equity in earnings of unconsolidated investments	237,110	54,531	2,759
Gain on remeasurement of unconsolidated investment	9,728	—	—
Other income, net	1,221	1,723	2,413
Total Other Income (Expense)	166,402	14,275	(10,342)
Net income	440,489	274,889	197,171
Net income attributable to noncontrolling interests	(6,499)	(4,365)	(24,268)
Net income attributable to partners	$ 433,990	$ 270,524	$ 172,903
Allocation of income to the limited partners:			
Net income attributable to partners	$ 433,990	$ 270,524	$ 172,903
Predecessor operations interest in net income	—	(6,995)	(12,357)
General partner interest in net income	(147,823)	(102,465)	(46,478)
Net income available to common unitholders	286,167	161,064	114,068
Basic net income per common unit	$ 3.93	$ 2.26	$ 1.95
Diluted net income per common unit	$ 3.90	$ 2.23	$ 1.91
Basic average number of common units outstanding	72,876	71,150	58,597
Diluted average number of common units outstanding	73,458	72,107	59,575

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

TALLGRASS ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF EQUITY

		Limited Partners				General Partner				
		Common		Subordinated						
	Predecessor Equity	Units	Amount	Units	Amount	Units	Amount	Total Partners' Equity	Noncontrolling Interests	Total Equity
	(in thousands)									
Balance at January 1, 2015	$ 19,402	32,834	$ 800,333	16,200	$ 274,133	835	$ (35,743)	$1,058,125	$ 756,428	$ 1,814,553
Net income	12,357	—	108,888	—	5,180	—	46,478	172,903	24,268	197,171
Issuance of units to public, net of offering costs	—	11,266	554,084	—	—	—	—	554,084	—	554,084
Distributions to unitholders	—	—	(118,729)	—	(7,857)	—	(35,248)	(161,834)	—	(161,834)
Noncash compensation expense	—	—	9,337	—	—	—	—	9,337	—	9,337
Common units issued under LTIP, net of units tendered by employees to satisfy tax withholding obligations	—	344	(6,603)	—	—	—	—	(6,603)	—	(6,603)
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)	—	—	—	—	—
Contributions from Predecessor Entities, net	39,805	—	—	—	—	—	—	39,805	—	39,805
Balance at December 31, 2015	$ 71,564	60,644	$ 1,618,766	—	$ —	835	$ (348,841)	$1,341,489	$ 445,077	$ 1,786,566
Net income	6,995	—	161,064	—	—	—	102,465	270,524	4,365	274,889
Issuance of units to public, net of offering costs	—	7,697	337,671	—	—	—	—	337,671	—	337,671
Issuance of units in a private placement, net of offering costs	—	2,417	90,009	—	—	—	—	90,009	—	90,009
Distributions to unitholders	—	—	(202,996)	—	—	—	(89,838)	(292,834)	—	(292,834)
Noncash compensation expense	—	—	7,879	—	—	—	—	7,879	—	7,879
Contributions from noncontrolling interest	—	—	—	—	—	—	—	—	9,304	9,304
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	(6,534)	(6,534)
Acquisition of additional 31.3% membership interest in Pony Express	—	6,518	268,607	—	—	—	(279,967)	(11,360)	(417,679)	(429,039)
Partial exercise of call option	—	(4,815)	(204,634)	—	—	—	(33,993)	(238,627)	—	(238,627)
Contributions from TD	—	—	—	—	—	—	17,894	17,894	—	17,894
Acquisition of noncontrolling interests	—	—	(5,373)	—	—	—	(59)	(5,432)	(568)	(6,000)
Common units issued under LTIP, net of units tendered by employees to satisfy tax withholding obligations	—	25	(498)	—	—	—	—	(498)	—	(498)
Contributions from Predecessor Entities, net	3,736	—	—	—	—	—	—	3,736	—	3,736
Balance at December 31, 2016	$ 82,295	72,486	$ 2,070,495	—	$ —	835	$ (632,339)	$1,520,451	$ 33,965	$ 1,554,416

TALLGRASS ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF EQUITY

	Predecessor Equity	Limited Partners				General Partner		Total Partners' Equity	Noncontrolling Interests	Total Equity
		Common		Subordinated						
		Units	Amount	Units	Amount	Units	Amount			
	(in thousands)									
Acquisition of Terminals and NatGas	(82,295)	—	—	—	—	—	(57,705)	(140,000)	—	(140,000)
Net income	—	—	286,167	—	—	—	147,823	433,990	6,499	440,489
Issuance of units to public, net of offering costs	—	2,341	112,420	—	—	—	—	112,420	—	112,420
Distributions to unitholders	—	—	(256,124)	—	—	—	(136,737)	(392,861)	—	(392,861)
Noncash compensation expense	—	—	10,390	—	—	—	—	10,390	—	10,390
Common units issued under LTIP, net of units tendered by employees to satisfy tax withholding obligations	—	683	(12,933)	—	—	—	—	(12,933)	—	(12,933)
Partial exercise of call option	—	(1,703)	(72,381)	—	—	—	(12,561)	(84,942)	—	(84,942)
Repurchase of common units from TD	—	(736)	(35,335)	—	—	—	—	(35,335)	—	(35,335)
Acquisition of additional 24.99% membership interest in Rockies Express	—	—	—	—	—	—	63,681	63,681	—	63,681
Acquisition of additional 40% membership interest in Deeprock Development	—	—	—	—	—	—	—	—	45,869	45,869
Acquisition of noncontrolling interests	—	129	6,617	—	—	—	—	6,617	(13,057)	(6,440)
Contributions from TD	—	—	—	—	—	—	2,301	2,301	—	2,301
Contributions from noncontrolling interest	—	—	—	—	—	—	—	—	1,589	1,589
Distributions to noncontrolling interest	—	—	—	—	—	—	—	—	(6,196)	(6,196)
Balance at December 31, 2017	$ —	73,200	$ 2,109,316	—	$ —	835	$ (625,537)	$1,483,779	$ 68,669	$ 1,552,448

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,		
	2017	2016	2015
		(in thousands)	
Cash Flows from Operating Activities:			
Net income	$ 440,489	$ 274,889	$ 197,171
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	98,064	93,605	88,949
Equity in earnings of unconsolidated investments	(237,110)	(54,531)	(2,759)
Distributions from unconsolidated investments	237,192	54,449	3,096
Gain on remeasurement of unconsolidated investment	(9,728)	—	—
Other noncash items, net	8,988	9,519	10,124
Changes in components of working capital:			
Accounts receivable and other	(57,937)	2,818	(15,936)
Accounts payable and accrued liabilities	85,071	10,502	10,211
Deferred revenue	27,283	33,815	20,612
Other current assets and liabilities	(10,542)	(5,578)	(6,143)
Other operating, net	(2,709)	95	(1,672)
Net Cash Provided by Operating Activities	579,061	419,583	303,653
Cash Flows from Investing Activities:			
Acquisition of Rockies Express membership interest	(400,000)	(436,022)	—
Capital expenditures	(145,144)	(84,491)	(120,718)
Acquisition of Terminals and NatGas	(140,000)	—	—
Acquisition of Douglas Gathering System	(128,526)	—	—
Distributions from unconsolidated investment in excess of cumulative earnings	69,434	24,120	1,552
Acquisition of Deeprock Development	(57,202)	—	—
Contributions to unconsolidated investments	(45,948)	(50,076)	(383)
Acquisition of PRB Crude System	(36,030)	—	—
Acquisition of Pony Express membership interest	—	(49,118)	(700,000)
Acquisition of Western	—	—	(75,000)
Other investing, net	(15,125)	48	(4,883)
Net Cash Used in Investing Activities	(898,541)	(595,539)	(899,432)
Cash Flows from Financing Activities:			
Proceeds from issuance of long-term debt	1,103,750	400,000	—
Distributions to unitholders	(392,861)	(292,834)	(161,834)
(Repayments) borrowings under revolving credit facility, net	(354,000)	262,000	194,000
Proceeds from public offering, net of offering costs	112,420	337,671	554,084
Partial exercise of call option	(72,381)	(204,634)	—
Repurchase of common units from TD	(35,335)	—	—
Payments for deferred financing costs	(22,250)	(10,251)	(1,522)
Acquisition of Pony Express membership interest	—	(425,882)	—
Proceeds from private placement, net of offering costs	—	90,009	—
Other financing, net	(19,927)	20,139	11,795
Net Cash Provided by Financing Activities	319,416	176,218	596,523
Net Change in Cash and Cash Equivalents	(64)	262	744

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

Cash and Cash Equivalents, beginning of period	1,873	1,611	867
Cash and Cash Equivalents, end of period	$ 1,809	$ 1,873	$ 1,611
Supplemental Disclosures:			
Cash payments for interest, net	$ (67,360)	$ (29,754)	$ (14,021)
Schedule of Noncash Investing and Financing Activities:			
Increase in accrual for payment of property, plant and equipment	$ 8,975	$ —	$ —
Common units issued as partial consideration to acquire additional 9% membership interest in Deeprock Development	$ 6,617	$ —	$ —
Property, plant and equipment acquired via the cash management agreement with TD	$ —	$ —	$ 138,936
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)

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

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. Our operations are 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, Bakken, Marcellus, and Utica shale formations. Our reportable business segments are:

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

Natural Gas Transportation. We provide natural gas transportation and storage services for customers in the Rocky Mountain, Midwest and Appalachian regions of the United States through: (1) our 49.99% membership interest in Rockies Express Pipeline LLC ("Rockies Express"), which owns the Rockies Express Pipeline, a FERC-regulated natural gas pipeline system extending from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio (the "Rockies Express Pipeline"), inclusive of the additional 24.99% membership interest acquired from Tallgrass Development, LP ("TD") effective March 31, 2017 as discussed in Note 3 - *Acquisitions*, and our 100% membership interest in Tallgrass NatGas Operator, LLC ("NatGas") acquired effective January 1, 2017, which operates the Rockies Express Pipeline, (2) 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 (3) the Trailblazer Pipeline system, a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Nebraska (the "Trailblazer Pipeline").

Crude Oil Transportation. We provide crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which owns a FERC-regulated crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma, and includes a lateral in Northeast Colorado commencing in Weld County, Colorado that interconnects with the pipeline just east of Sterling, Colorado (the "Pony Express System").

Gathering, Processing & Terminalling. We provide natural gas gathering and processing services for customers in Wyoming through: (1) a natural gas gathering system in the Powder River Basin (the "Douglas Gathering System") that was acquired on June 5, 2017, as discussed in Note 3 – *Acquisitions*, (2) the Casper and Douglas natural gas processing facilities, and (3) the West Frenchie Draw natural gas treating facility. We also provide crude oil gathering services for customers in Wyoming through a crude oil gathering system in the Powder River Basin (the "PRB Crude System") that was acquired on August 3, 2017, as discussed in Note 3 – *Acquisitions;* and NGL transportation services in Northeast Colorado and Wyoming. We perform water business services, including freshwater transportation and produced water gathering and disposal, in Colorado, Texas, and Wyoming through BNN Water Solutions, LLC ("Water Solutions"), and crude oil storage and terminalling services through our 100% membership interest in Tallgrass Terminals, LLC ("Terminals") acquired effective January 1, 2017, which owns and operates crude oil terminals near Sterling, Colorado (the "Sterling Terminal") and in Weld County, Colorado (the "Buckingham Terminal"). Terminals also owns a 69% membership interest in Deeprock Development, LLC ("Deeprock Development"), which owns a crude oil terminal in Cushing, Oklahoma (the "Cushing Terminal"), inclusive of an additional 49% membership interest in Deeprock Development acquired in July 2017 as discussed in Note 3 – *Acquisitions*. The Gathering, Processing & Terminalling segment also includes newly formed Stanchion Energy, LLC ("Stanchion"), which transacts in crude oil. As discussed in Note 20 – *Subsequent Events*, on January 2, 2018, Terminals acquired an approximately 38% interest in Deeprock North, LLC ("Deeprock North"), which was merged into Deeprock Development immediately following the acquisition, and on January 12, 2018, Water Solutions acquired a 100% membership interest in Buckhorn Energy Services, LLC and Buckhorn SWD Solutions, LLC (collectively, "BNN North Dakota").

The table below summarizes our equity ownership as of December 31, 2017:

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	47,580,535	—	65.00%	64.27%
Tallgrass Equity, LLC	20,000,000	—	27.32%	27.01%
Tallgrass Development, LP [(1)]	5,619,218	—	7.68%	7.59%
Tallgrass MLP GP, LLC [(2)]	—	834,391	—%	1.13%
Total	73,199,753	834,391	100.00%	100.00%

(1) Effective February 7, 2018, Tallgrass Equity, LLC ("Tallgrass Equity") acquired the 5,619,218 common units held by TD in connection with the merger of TD into Tallgrass Development Holdings, LLC, a wholly-owned subsidiary of Tallgrass Equity ("Tallgrass Development Holdings").

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

The term "Terminals Predecessor" refers to Terminals and the term "NatGas Predecessor" refers to NatGas prior to their acquisition by TEP on January 1, 2017. Terminals Predecessor and NatGas 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 Terminals Predecessor and NatGas Predecessor prior to January 1, 2017. For additional information regarding these acquisitions, see Note 3 – *Acquisitions*.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements and related notes were prepared in conformity with accounting principles generally accepted in the United States of America ("GAAP"). In this report, the Financial Accounting Standards Board is referred to as the FASB and the FASB Accounting Standards Codification is referred to as the Codification or ASC. Certain prior period amounts have been reclassified to conform to the current presentation.

As further discussed in Note 3 – *Acquisitions*, TEP closed the acquisition of Terminals and NatGas effective January 1, 2017. As the acquisitions of Terminals and NatGas are considered transactions between entities under common control, and a change in reporting entity, the financial information presented has been recast to include Terminals and NatGas for all periods presented. Net equity contributions of the Predecessor Entities included in the consolidated financial statements represent transfers of cash as a result of TD's centralized cash management system prior to January 1, 2017 for Terminals and NatGas, under which cash balances were swept daily and recorded as loans from the subsidiaries of TD. These loans were then periodically recorded as equity distributions.

The accompanying consolidated financial statements of TEP include historical cost-basis accounts of the assets of Terminals and NatGas for the periods prior to January 1, 2017, the date TEP acquired Terminals and NatGas from TD, 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. TEP and the Predecessor Entities are all 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.

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. Prior to January 1, 2016, Pony Express participated in a cash management agreement with TD, which currently holds a 2.0% common membership interest in Pony Express, under which cash balances were swept periodically and recorded as loans from Pony Express to TD. Effective January 1, 2016, Pony Express entered into a cash management agreement with TEP.

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 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 are 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. Pony Express was considered to be a VIE under the applicable authoritative guidance prior to our acquisition of an additional 31.3% membership interest effective January 1, 2016. Effective January 1, 2016, Pony Express is no longer considered to be a VIE. We continue to consolidate our membership interest in Pony Express.

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.

Net equity contributions 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 January 1, 2017 for Terminals and NatGas, 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.

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 $0.5 million and $0.6 million at December 31, 2017 and 2016, 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 and net realizable value 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 and net realizable value 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 $2.6 million and $2.9 million included in "Prepayments and other current assets" and "Deferred charges and other assets" in the consolidated balance sheets at December 31, 2017 and 2016, respectively. Regulatory assets at December 31, 2017 and December 31, 2016 were primarily attributable to costs associated with both TIGT's 2015 Rate Case Filing and Trailblazer's 2013 Rate Case Filing as well as fuel tracker assets at our regulated natural gas pipelines. We recorded regulatory liabilities of approximately $2.3 million and $1.7 million included in "Other current liabilities" in the consolidated balance sheets at December 31, 2017 and 2016, respectively, related to fuel tracker liabilities at our regulated natural gas pipelines. For further information regarding our rate case filings and fuel tracker balances, see 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 and/or the negative salvage liability discussed under *"Depreciation and Amortization"* below, as appropriate, 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 establish identifiable intangible assets when they meet either the separability criterion or the contractual-legal criterion. 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. Other intangible assets include customer contracts amortized on a straight-line basis over a period of 2 to 8 years, based on the remaining term of the contracts at the time of acquisition.

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 asset 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 or asset group to its carrying amount. If the carrying amount is higher than the undiscounted future cash flows, the fair value of the asset or asset group 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 and net realizable value.

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 depreciation rates for our regulated natural gas pipeline assets include two components, one based on economic service life (capital recovery) and one based on net costs of removal (negative salvage). The accumulated liability related to negative salvage is classified as "Other long-term liabilities and deferred credits" in our consolidated balance sheets.

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 - 5.0%
Gathering & processing assets	2.2 - 5.0%
Water business assets	2.3 - 20.0%
Terminal assets	1.8 - 2.8%
Replacement Gas Facilities (1)	10.0%
General & other	2.5 - 25.0%

(1) Represents costs incurred by TIGT, and reimbursed by Pony Express, for the construction of certain gas facilities necessary to maintain existing natural gas service on the TIGT System after having sold approximately 433 miles of natural gas pipeline, and associated rights of way and certain other equipment, to Pony Express in 2013.

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. Deferred financing costs associated with long-term debt are presented as a reduction to the corresponding debt in our consolidated balance sheets. Deferred financing costs associated with our revolving credit facility are presented as noncurrent assets in our consolidated balance sheets.

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 fair value over carrying amount in the last valuation or changes in the business environment. Our annual impairment testing date is August 31. We evaluate goodwill for impairment at the reporting unit level, which is the same as, or one level below, an operating segment as defined in the segment reporting guidance of the Codification, using either the qualitative assessment option or proceeding directly to the quantitative impairment test 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, then goodwill is not considered impaired. When goodwill is evaluated for impairment using the quantitative impairment test, the carrying amount of the reporting unit is compared to its fair value. If the fair value exceeds the carrying amount, goodwill is not considered impaired. If the carrying amount exceeds the reporting unit's fair value, then the reporting unit should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. See Note 7 – *Goodwill and Other Intangible Assets* for additional information regarding impairment testing performed during 2017.

Investment in Unconsolidated Affiliates

We use the equity method to account for investments in 20% or greater 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. See Note 8 – *Investments in Unconsolidated Affiliates* for additional information regarding our investment in unconsolidated affiliates.

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 transportation and storage services and crude oil transportation services to our customers in which the commodity remains the property of these customers at all times.

Natural gas transportation and storage services occur in the Natural Gas Transportation 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.

Crude oil transportation services occur in the Crude Oil Transportation 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 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 liquids sales occur in the Gathering, Processing & Terminalling 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 Gathering, Processing & Terminalling segment.

Natural gas sales occur in both the Natural Gas Transportation segment and in the Gathering, Processing & Terminalling segment. In the Natural Gas Transportation 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. As of the date of the TIGT rate case settlement in 2016, all of our regulated gas pipelines operate under fuel tracker mechanisms, as discussed under "Accounting for Regulatory Activities" above, and as a result our regulated gas pipelines no longer recognize revenue associated with volumes retained from the customer. 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 Gathering, Processing & Terminalling 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 crude oil and 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

TEP is comprised primarily of limited liability companies that are considered flow-through entities (partnerships or disregarded entities) for income tax purposes. 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. In addition, during the year ended December 31, 2015, we formed Tallgrass Energy Finance Corp., a wholly owned subsidiary that has no material assets and was formed for the sole purpose of being a co-issuer of our senior notes as discussed in Note 10 – *Long-term Debt*. On September 29, 2017, TEP, through its membership interest in TIGT, formed a new C corporation, Cheyenne Connector Pipeline, Inc. ("Cheyenne Connector"), for the purpose of the construction of a pipeline lateral in Northeast Colorado that would interconnect with Rockies Express Pipeline's Cheyenne Hub. Cheyenne Connector has not yet commenced operations or generated any income. Accordingly, no provision for federal or state income taxes has been recorded in our consolidated financial statements.

Business Combinations

We recognize and measure the assets acquired and liabilities assumed in a business combination based on their estimated fair values at the acquisition date, with any remaining difference recorded as goodwill or gain from a bargain purchase. For material acquisitions, management typically engages an independent valuation specialist to assist with the determination of fair value of the assets acquired, liabilities assumed, noncontrolling interest, if any, and goodwill, based on recognized business valuation methodologies. If the initial accounting for the business combination is incomplete by the end of the reporting period in which the acquisition occurs, an estimate will be recorded. Subsequent to the acquisition, and not later than one year from the acquisition date, we will record any material adjustments to the initial estimate based on new information obtained about facts and circumstances that existed as of the acquisition date. An income, market or cost valuation method may be utilized to estimate the fair value of the assets acquired, liabilities assumed, and noncontrolling interest, if any, in a business combination. The income valuation method represents the present value of future cash flows over the life of the asset using: (i) discrete financial forecasts, which rely on management's estimates of volumes, commodity prices, revenue and operating expenses; (ii) long-term growth rates; and (iii) appropriate discount rates. The market valuation method uses prices paid for a reasonably similar asset by other purchasers in the market, with adjustments relating to any differences between the assets. The cost valuation method is based on the replacement cost of a comparable asset at prices at the time of the acquisition reduced for depreciation of the asset. See Note 3 – *Acquisitions* for additional information regarding our business combinations.

Accounting Pronouncements Recently Adopted

ASU No. 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business"

In January 2017, the FASB issued Accounting Standards Update ("ASU") No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business. ASU 2017-01 clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses by providing a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. This screen reduces the number of transactions that need to be further evaluated. The ASU also narrows the definition of the term "output" so that the term is consistent with how outputs are described under the revenue recognition guidance in Topic 606.

The amendments in ASU 2017-01 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2017. Early adoption is permitted in certain circumstances. We elected to adopt the guidance in ASU 2017-01 effective April 1, 2017. As a result of the early adoption of ASU 2017-01, our acquisition of the Douglas Gathering System, as discussed in Note 3 – *Acquisitions*, was accounted for as an asset acquisition.

ASU No. 2017-04, "Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment"

In January 2017, the FASB issued ASU No. 2017-04, which simplifies the subsequent measurement of goodwill by eliminating "Step 2" from the goodwill impairment test, which involved calculating the implied fair value of goodwill by determining the fair value at the impairment testing date of a reporting unit's assets and liabilities. Instead, under the simplified test approach, an entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit.

The amendments in ASU 2017-04 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. We elected to adopt the guidance in ASU 2017-04 effective April 1, 2017, and as a result applied the new guidance to our annual goodwill impairment tests performed as of August 31, 2017.

ASU No. 2016-09, "Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting"

In March 2016, the FASB issued ASU No. 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. ASU 2016-09 simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. Among other changes, ASU 2016-09 allows an entity to make an entity-wide accounting policy election to either estimate the number of awards expected to vest (consistent with current GAAP) or account for forfeitures when they occur.

The amendments in ASU 2016-09 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 adopted the guidance in ASU 2016-09 effective January 1, 2017 and made a policy election to account for forfeitures when they occur. The adoption of ASU 2016-09 did not have a material impact on our consolidated financial statements.

Accounting Pronouncements Not Yet Adopted

Revenue Recognition

In May 2014, the 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.

Subsequent to issuing ASU 2014-09, the FASB has issued a series of subsequent updates to the revenue recognition guidance in Topic 606, including ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients, ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers, and ASU No. 2017-13, Revenue Recognition (Topic 605), Revenue from Contracts with Customers (Topic 606), Leases (Topic 840), and Leases (Topic 842): Amendments to SEC Paragraphs Pursuant to the Staff Announcement at the July 20, 2017 EITF Meeting and Rescission of Prior SEC Staff Announcements and Observer Comments. The amendments in ASU 2014-09, ASU 2016-08, ASU 2016-10, ASU 2016-12, ASU 2016-20, and ASU 2017-13 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period.

Management has completed its evaluation and implemented the revised guidance using the modified retrospective method as of January 1, 2018. This approach allows us to apply the new standard to (i) all new contracts entered into after January 1, 2018 and (ii) all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of January 1, 2018 through a cumulative adjustment to members' equity. Consolidated revenues presented in the comparative consolidated financial statements for periods prior to January 1, 2018 will not be revised.

On January 1, 2018, we recorded a cumulative effect adjustment to equity of $44.1 million, increased the carrying amount of our investment in Rockies Express by $42.8 million, and recognized a receivable from Rockies Express of $1.3 million. These adjustments relate to the cumulative effect adjustment recorded by Rockies Express of $125.2 million upon adoption of ASC 606. The cumulative effect adjustment at Rockies Express arose as a result of the allocation of the transaction price to a series of individual performance obligations in certain long-term transportation contracts with tiered-pricing arrangements. The adjustment increases the carrying amount of our investment in Rockies Express to reflect increased equity in earnings and establishes a receivable for the increased management fee revenue that would have been earned by NatGas during the periods prior to implementation.

Through our review process, we also identified the following changes to our revenue recognition policies that did not result in a cumulative effect adjustment on January 1, 2018:

- *Gathering & Processing.* We have determined that a number of our gathering & processing contracts at TMID do not represent customer arrangements under ASC 606. Instead, arrangements deemed to represent wellhead purchases of raw gas will be accounted for as supply arrangements pursuant to ASC 705. As a result, gathering & processing fees previously recognized in revenue will be reported as a reduction to cost of sales under ASC 606.
- *Pipeline Loss Allowance.* We have determined that pipeline loss allowance, or PLA, collected under certain crude oil transportation arrangements is a component of the transaction price where the PLA both significantly exceeds actual losses and was negotiated with the intent of providing a revenue stream to TEP. Under ASC 606, PLA barrels retained from customers will be subject to the guidance for noncash consideration and recognized in revenue at their contract inception fair value.

We anticipate significant changes to our disclosures based on the additional requirements prescribed by the standard. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is (or will be) recognized and data related to contract assets and liabilities. Additionally, we are continuing to provide internal training and awareness related to the revised guidance to key stakeholders throughout our organization and evaluate our business processes, systems and controls to ensure the accuracy and timeliness of the recognition and disclosure requirements under the new revenue guidance.

ASU No. 2016-02, "Leases (Topic 842)"

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). ASU 2016-02 provides a comprehensive update to the lease accounting topic in the Codification intended to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The amendments in ASU 2016-02 include a revised definition of a lease as well as certain scope exceptions. The changes primarily impact lessee accounting, while lessor accounting is largely unchanged from previous GAAP.

Management is currently evaluating the impact of our pending adoption of ASC 842. The status of our implementation is as follows:

- Management has formed an implementation team that meets to discuss implementation challenges, technical interpretations, industry-specific treatment of certain contract types, and project status.
- Management is in the process of gathering data and reviewing contracts in order to identify all impacted contracts.
- Management is evaluating the potential information technology and internal control changes that will be required for adoption based on the findings from its contract review process.
- Management plans to provide internal training and awareness related to the revised guidance to the key stakeholders throughout its organization.

The amendments in ASU 2016-02 are effective for public entities for annual reporting periods beginning after December 15, 2018, and for interim periods within that reporting period. Early application is permitted. We are currently evaluating the impact of ASU 2016-02.

3. Acquisitions

Acquisition of Outrigger Powder River Operating, LLC

On August 3, 2017, we acquired 100% of the membership interests of Outrigger Powder River Operating, LLC (subsequently renamed as Tallgrass Crude Gathering, LLC, "TCG"), which owns the PRB Crude System, a crude oil gathering system in the Powder River Basin with approximately 34 miles of gathering lines as of the acquisition date and approximately 150,000 acres dedicated on a long-term fee-based contract, for approximately $36 million. The transaction qualifies as an acquisition of a business and is accounted for as a business combination under ASC 805.

The following represents the fair value of assets acquired and liabilities assumed at August 3, 2017 (in thousands):

Accounts receivable	$	117	
Property, plant and equipment		29,306	
Intangible asset		6,694	(1)
Accounts payable and accrued liabilities		(87)	
Net identifiable assets acquired	$	36,030	

(1) The $6.7 million intangible asset acquired represents a major customer contract. This intangible asset is amortized on a straight-line basis over a period of 8 years, the remaining term of the contract at the time of acquisition.

At September 30, 2017, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. No adjustments were made to these provisional amounts and the allocation of assets acquired and liabilities assumed in the acquisition was considered final as of December 31, 2017. Actual revenue and net loss attributable to TEP from TCG of less than $1 million was recognized in the accompanying consolidated statements of income for the period from August 3, 2017 to December 31, 2017.

Acquisitions of Additional Interests in Deeprock Development, LLC

On July 20, 2017, we acquired an additional 40% membership interest in Deeprock Development from Kinder Morgan Cushing, LLC for cash consideration of approximately $57.2 million, net of cash acquired. We subsequently acquired an additional 9% membership interest in Deeprock Development from Deeprock Energy Resources LLC ("DER") on July 21, 2017, as discussed further below.

Upon closing of the acquisition of the 40% membership interest on July 20, 2017, we obtained a controlling financial interest in Deeprock Development and accordingly have accounted for the transaction as a step acquisition under ASC 805. On the acquisition date, TEP remeasured its previously held 20% equity interest in Deeprock Development to its fair value of $22.9 million, recognized a gain of $9.7 million in "Gain on remeasurement of unconsolidated investment" in the consolidated statements of income, and consolidated Deeprock Development in our consolidated financial statements. The 40% equity interest in Deeprock Development held by noncontrolling interests was recorded at its acquisition date fair value of $45.9 million. The fair values of the previously held equity interest and the noncontrolling interest were determined using a discounted cash flow analysis and adjusted for lack of control. These fair value measurements are based on significant inputs, such as forecasted cash flows and discount rates, 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.

The following represents the fair value of assets acquired and liabilities assumed at July 20, 2017 (in thousands):

Accounts receivable	$	968
Other current assets		598
Property, plant and equipment		70,148
Accounts payable		(712)
Deferred revenue		(6,546)
Net identifiable assets acquired		64,456
Goodwill		61,550
Net assets acquired (excluding cash)	$	126,006

At September 30, 2017, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. No adjustments were made to these provisional amounts and the allocation of assets acquired and liabilities assumed in the acquisition was considered final as of December 31, 2017. The goodwill recognized of $61.6 million is primarily attributed to synergies expected from combining the operations of TEP and Deeprock Development. All the goodwill was assigned to our Gathering, Processing & Terminalling segment. Actual revenue and net income attributable to TEP from Deeprock Development of $10.5 million and $8.5 million, respectively, was recognized in the accompanying consolidated statements of income for the period from July 20, 2017 to December 31, 2017.

On July 21, 2017, subsequent to the acquisition of an additional 40% membership interest discussed above, we acquired an additional 9% membership interest in Deeprock Development from DER for total consideration valued at approximately $13.1 million, consisting of approximately $6.4 million in cash and the issuance of 128,790 common units (valued at approximately $6.7 million based on the July 20, 2017 closing price of TEP's common units), which was accounted for as an acquisition of noncontrolling interest. Subsequent to the closing of the transaction, our aggregate membership interest in Deeprock Development is 69%.

Acquisition of DCP Douglas, LLC

On June 5, 2017, we acquired 100% of the membership interests in DCP Douglas, LLC (subsequently renamed as Tallgrass Midstream Gathering, LLC), which owns the Douglas Gathering System, a natural gas gathering system in the Powder River Basin with approximately 1,500 miles of gathering pipeline connected to the Douglas processing plant, for approximately $128.5 million, subject to working capital adjustments. The acquisition has been accounted for as an asset acquisition, with substantially all the fair value allocated to the long-lived assets acquired based on their relative fair values.

Acquisitions of 49.99% in Rockies Express Pipeline LLC

On May 6, 2016, TD assigned us its right to purchase a 25% membership interest in Rockies Express from a unit of Sempra U.S. Gas and Power ("Sempra") pursuant to the purchase agreement originally entered into between TD's wholly-owned subsidiary and Sempra in March 2016. Subsequently on May 6, 2016, we closed the purchase of a 25% membership interest in Rockies Express from Sempra pursuant to the purchase agreement for cash consideration of approximately $436.0 million, after making the adjustments to the purchase price required by the purchase agreement.

On March 31, 2017, TEP, TD, and Rockies Express Holdings, LLC, entered into a definitive Purchase and Sale Agreement, pursuant to which we acquired an additional 24.99% membership interest in Rockies Express from TD in exchange for cash consideration of $400 million. Together with the 25% membership interest in Rockies Express that we acquired from a unit of Sempra U.S. Gas and Power on May 6, 2016, this transaction increases our aggregate membership interest in Rockies Express to 49.99%. For additional information, see Note 8 – *Investments in Unconsolidated Affiliates*.

Acquisition of Tallgrass Terminals, LLC and Tallgrass NatGas Operator, LLC

Effective January 1, 2017, we acquired 100% of the issued and outstanding membership interests in Terminals and 100% of the issued and outstanding membership interests in NatGas from TD for total cash consideration of $140 million. These acquisitions are considered transactions between entities under common control, and a change in reporting entity.

Terminals owns several fully operational assets providing storage capacity and additional injection points for the Pony Express System, including the Sterling Terminal near Sterling, Colorado, the Buckingham Terminal in northeast Colorado, and a 69% interest in the Deeprock Development Terminal in Cushing, Oklahoma following the acquisition of an aggregate additional 49% membership interest in Deeprock Development in July 2017 discussed above. Terminals also owns acreage in Cushing, Oklahoma and Guernsey, Wyoming, which is under development to provide additional storage capacity and other potential opportunities.

NatGas is the operator of the Rockies Express Pipeline and receives a fee from Rockies Express as compensation for its services.

Acquisitions of 100% 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. The terms of TEP's 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 with distributions thereafter shared in accordance with the terms of the Second Amended Pony Express LLC Agreement.

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. The transaction resulted in a deemed distribution to our general partner as discussed further in Note 11 – *Partnership Equity and Distributions*.

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 our common units) issued to TD, for total consideration of approximately $743.6 million. The transaction increased our aggregate membership interest in Pony Express to 98%. As part of the transaction, TD granted us an 18-month call option covering the newly issued 6,518,000 common units at a price of $42.50. On the effective date of the acquisition, the call option was valued at $46.0 million. As discussed in Note 9 – Risk Management, in July 2016 and October 2016, we partially exercised the option covering 3,563,146 and 1,251,760 of the common units, respectively. On February 1, 2017, we exercised the remainder of the call option covering an additional 1,703,094 common units, leaving no remaining common units subject to the call option as of such date. As a result of the partial exercises in 2016 and 2017, TEP derecognized a portion of the derivative asset balance, recognizing approximately $34.0 million and $12.6 million through equity for the years ended December 31, 2016 and 2017, respectively, as discussed further in Note 11 – *Partnership Equity and Distributions*.

The acquisition of the additional 31.3% 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 has not been recast to reflect the additional 31.3% membership interest. The transaction resulted in a deemed distribution to our general partner as discussed further in Note 11 – *Partnership Equity and Distributions*.

Cash outflows to acquire an additional noncontrolling interest in Pony Express are classified as an investing activity in the accompanying consolidated statements of cash flows to the extent the consideration paid was used to directly fund the construction of the underlying assets by the noncontrolling member. Cash outflows to acquire an additional noncontrolling interest in excess of the cost to construct the underlying assets are classified as financing activities. For the year ended December 31, 2016, $49.1 million of the $475 million paid to acquire the additional 31.3% membership interest in Pony Express was classified as an investing activity and $425.9 million was classified as a financing activity.

As discussed in Note 20 – *Subsequent Events*, we acquired the remaining 2% of Pony Express from TD effective February 1, 2018.

Acquisition of BNN Western, LLC

On December 16, 2015, Whiting Oil and Gas Corporation ("Whiting"), BNN Redtail, LLC ("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. As part of the transaction with Whiting, Whiting also executed a five-year fresh water service contract and a nine-year gathering and disposal contract, each of which commenced in December 2015.

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. No adjustments were made to these provisional amounts and the allocation of assets acquired and liabilities assumed in the acquisition was considered final as of September 30, 2016.

Pro Forma Financial Information

Unaudited pro forma revenue and net income attributable to TEP for the years ended December 31, 2017 and 2016 is presented below as if the acquisitions of TCG and Deeprock Development had been completed on January 1, 2016. Unaudited pro forma revenue and net income attributable to TEP for the year ended December 31, 2015 is presented below as if the acquisition of Western had been completed on January 1, 2015.

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Revenue	$ 667,391	$ 632,528	$ 544,497
Net income attributable to partners	$ 427,522	$ 275,506	$ 173,542

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 the estimated results of operations of TCG, Deeprock Development, and Western for the periods presented, as well as to eliminate the equity in earnings and gain on remeasurement of unconsolidated investment associated with our previously held 20% membership interest in Deeprock Development.

Historical Financial Information

The results of our acquisitions of Terminals and NatGas are included in the consolidated balance sheets as of December 31, 2017 and December 31, 2016. The following table presents our previously reported December 31, 2016 consolidated balance sheet, adjusted for the acquisitions of Terminals and NatGas:

	December 31, 2016			
	TEP (As previously reported)	Consolidate Terminals	Consolidate NatGas	TEP (As currently reported)
	(in thousands)			
ASSETS				
Current Assets:				
Cash and cash equivalents	$ 1,873	$ —	$ —	$ 1,873
Accounts receivable, net	59,469	38	29	59,536
Gas imbalances	1,597	—	—	1,597
Inventories	12,805	288	—	13,093
Derivative assets	10,967	—	—	10,967
Prepayments and other current assets	6,820	808	—	7,628
Total Current Assets	93,531	1,134	29	94,694
Property, plant and equipment, net	2,012,263	66,969	—	2,079,232
Goodwill	343,288	—	—	343,288
Intangible assets, net	93,522	—	—	93,522
Unconsolidated investments	461,915	13,710	—	475,625
Deferred financing costs, net	4,815	—	—	4,815
Deferred charges and other assets	9,637	1,400	—	11,037
Total Assets	$ 3,018,971	$ 83,213	$ 29	$ 3,102,213
LIABILITIES AND EQUITY				
Current Liabilities:				
Accounts payable	$ 24,076	$ 46	$ —	$ 24,122
Accounts payable to related parties	5,879	56	—	5,935
Gas imbalances	1,239	—	—	1,239
Derivative liabilities	556	—	—	556
Accrued taxes	16,328	668	—	16,996
Accrued liabilities	16,525	177	—	16,702
Deferred revenue	60,757	—	—	60,757
Other current liabilities	6,446	—	—	6,446
Total Current Liabilities	131,806	947	—	132,753
Long-term debt, net	1,407,981	—	—	1,407,981
Other long-term liabilities and deferred credits	7,063	—	—	7,063
Total Long-term Liabilities	1,415,044	—	—	1,415,044
Equity:				
Net Equity	1,472,121	82,266	29	1,554,416
Total Equity	1,472,121	82,266	29	1,554,416
Total Liabilities and Equity	$ 3,018,971	$ 83,213	$ 29	$ 3,102,213

The results of our acquisitions of Terminals and NatGas are included in the consolidated statements of income for the years ended December 31, 2017, 2016, and 2015. The following tables present the previously reported consolidated statements of income for the years ended December 31, 2016 and 2015, adjusted for the acquisitions of Terminals and NatGas:

	Year Ended December 31, 2016				
	TEP (As previously reported)	Consolidate Terminals	Consolidate NatGas	Elimination	TEP (As currently reported)
			(in thousands)		
Revenues:					
Crude oil transportation services	$ 374,949	$ —	$ —	$ —	$ 374,949
Natural gas transportation services	119,962	—	—	—	119,962
Sales of natural gas, NGLs, and crude oil	77,394	99	—	(370) (1)	77,123
Processing and other revenues	32,817	12,043	6,228	(11,460) (2)	39,628
Total Revenues	605,122	12,142	6,228	(11,830)	611,662
Operating Costs and Expenses:					
Cost of sales	71,920	100	—	(370) (1)	71,650
Cost of transportation services	58,341	788	—	(11,460) (2)	47,669
Operations and maintenance	53,386	1,684	—	—	55,070
Depreciation and amortization	84,896	1,351	—	—	86,247
General and administrative	53,633	1,469	—	—	55,102
Taxes, other than income taxes	24,727	673	—	—	25,400
Contract termination	—	8,061 (3)	—	—	8,061
Loss on disposal of assets	1,849	—	—	—	1,849
Total Operating Costs and Expenses	348,752	14,126	—	(11,830)	351,048
Operating Income (Expense)	256,370	(1,984)	6,228	—	260,614
Other Income (Expense):					
Interest expense, net	(40,688)	—	—	—	(40,688)
Unrealized loss on derivative instrument	(1,291)	—	—	—	(1,291)
Equity in earnings of unconsolidated investments	51,780	2,751	—	—	54,531
Other income, net	1,723	—	—	—	1,723
Total Other Income	11,524	2,751	—	—	14,275
Net income	267,894	767	6,228	—	274,889
Net income attributable to noncontrolling interests	(4,365)	—	—	—	(4,365)
Net income attributable to partners	$ 263,529	$ 767	$ 6,228	$ —	$ 270,524

	Year Ended December 31, 2015				
	TEP (As previously reported)	Consolidate Terminals	Consolidate NatGas	Elimination	TEP (As currently reported)
			(in thousands)		
Revenues:					
Crude oil transportation services	$ 300,436	$ —	$ —	$ —	$ 300,436
Natural gas transportation services	119,895	—	—	—	119,895
Sales of natural gas, NGLs, and crude oil	82,133	—	—	—	82,133
Processing and other revenues	33,733	7,689	6,332	(7,557) (2)	40,197
Total Revenues	536,197	7,689	6,332	(7,557)	542,661
Operating Costs and Expenses:					
Cost of sales	75,285	—	—	—	75,285
Cost of transportation services	53,597	800	—	(7,557) (2)	46,840
Operations and maintenance	49,138	1,685	—	—	50,823
Depreciation and amortization	83,476	782	—	—	84,258
General and administrative	50,195	1,156	—	—	51,351
Taxes, other than income taxes	21,796	—	—	—	21,796
Loss on disposal of assets	4,795	—	—	—	4,795
Total Operating Costs and Expenses	338,282	4,423	—	(7,557)	335,148
Operating Income	197,915	3,266	6,332	—	207,513
Other Income (Expense):					
Interest expense, net	(15,514)	—	—	—	(15,514)
Equity in earnings of unconsolidated investments	—	2,759	—	—	2,759
Other income, net	2,413	—	—	—	2,413
Total Other (Expense) Income	(13,101)	2,759	—	—	(10,342)
Net income	184,814	6,025	6,332	—	197,171
Net income attributable to noncontrolling interests	(24,268)	—	—	—	(24,268)
Net income attributable to partners	$ 160,546	$ 6,025	$ 6,332	$ —	$ 172,903

(1) Represents the elimination of revenue and cost of sales associated with the purchase of crude oil from Pony Express by Terminals.

(2) Represents the elimination of revenue and cost of transportation services associated with the lease of the Sterling Terminal facilities by Pony Express.

(3) Represents a one-time charge related to the termination of an operating agreement at the Sterling Terminal.

4. Related Party Transactions

As a result of our relationship with Tallgrass Energy Holdings and its affiliates, we have entered into a number of related party transactions. The following disclosure includes those related party transactions which are not otherwise disclosed in these notes to our consolidated financial statements.

We have no employees. In connection with the closing of our initial public offering on May 17, 2013, TEP and its general partner entered into an Omnibus Agreement with Tallgrass Energy Holdings and certain of its affiliates (the "TEP Omnibus Agreement"). The TEP Omnibus Agreement provides that, among other things, TEP will reimburse Tallgrass Energy Holdings 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 Tallgrass Energy Holdings and its affiliates, 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.

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 January 1, 2017 for Terminals and NatGas. Balances lent to TD under the Pony Express cash management agreement effective September 1, 2014 were classified as related party receivables in the consolidated balance sheets. There was no interest income from TD recognized for the years ended December 31, 2017 and 2016. During the year ended December 31, 2015 we recognized interest income from TD of $0.4 million on the receivable balance under the Pony Express cash management agreement in effect through December 31, 2015.

Totals of transactions with affiliated companies, excluding transactions disclosed elsewhere in these notes, are as follows:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Processing and other revenues[1]	$ 8,516	$ 6,228	$ 6,331
Cost of transportation services [2]	$ 10,476	$ 18,585	$ 18,288
Charges to TEP: [3]			
Property, plant and equipment, net	$ 2,679	$ 3,084	$ 4,342
Other deferred charges	$ 25	$ 44	$ 7
Operations and maintenance	$ 29,881	$ 25,431	$ 23,658
General and administrative	$ 41,032	$ 39,574	$ 33,820

(1) Reflects the fee that NatGas receives as the operator of the Rockies Express Pipeline.

(2) Reflects rent expense for the crude oil storage at the Deeprock Terminal prior to our consolidation of Deeprock Development during the third quarter of 2017, as discussed in Note 3 – *Acquisitions.*

(3) Charges to TEP include directly charged wages and salaries, other compensation and benefits, and shared services.

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

	December 31, 2017	December 31, 2016
	(in thousands)	
Receivable from related parties:		
Rockies Express Pipeline LLC	$ 1,340	$ 590
Total receivable from related parties	$ 1,340	$ 590
Accounts payable to related parties:		
Tallgrass Operations, LLC	$ 5,381	$ 5,854
Tallgrass Equity, LLC	80	68
Deeprock Development, LLC	—	13
Total accounts payable to related parties	$ 5,461	$ 5,935

Gas imbalances with affiliated shippers are as follows:

	December 31, 2017	December 31, 2016
	(in thousands)	
Affiliate gas imbalance receivables	$ 18	$ 177
Affiliate gas imbalance payables	$ 442	$ —

5. Inventory

The components of inventory at December 31, 2017 and 2016 consisted of the following:

	December 31, 2017	December 31, 2016
	(in thousands)	
Crude oil	$ 12,792	$ 5,462
Materials and supplies	5,891	6,383
Natural gas liquids	942	265
Gas in underground storage	1,984	983
Total inventory	$ 21,609	$ 13,093

6. Property, Plant and Equipment

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

	December 31, 2017	December 31, 2016
	(in thousands)	
Crude oil pipelines	$ 1,220,379	$ 1,202,125
Gathering, processing and terminalling assets (1)	675,092	397,701
Natural gas pipelines	581,400	572,150
General and other	98,680	82,510
Construction work in progress	97,978	20,606
Accumulated depreciation and amortization	(279,192)	(195,860)
Total property, plant and equipment, net (2)	$ 2,394,337	$ 2,079,232

(1) Includes approximately $138.2 million of assets associated with the Douglas Gathering System acquired in June 2017, approximately $68.4 million of assets associated with the acquisition of the aggregate additional 49% membership interest in Deeprock Development in July 2017, and approximately $29.3 million of assets associated with the PRB Crude System acquired in August 2017.

(2) Property, plant and equipment, net includes approximately $431.6 million of assets at our regulated natural gas pipelines at December 31, 2017.

Depreciation expense was approximately $86.9 million, $83.2 million, and $76.3 million for the years ended December 31, 2017, 2016, and 2015, respectively. Capitalized interest was approximately $1.1 million, $0.6 million, and $0.9 million for the years ended December 31, 2017, 2016, and 2015, respectively.

Under lease agreements effective October 3, 2015 and January 1, 2017, TMID, as lessor, leases capacity on NGL pipelines that were constructed for third parties. Rental income was approximately $3.8 million, $3.2 million, and $0.8 million for the years ended December 31, 2017, 2016, and 2015, respectively, 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 for the years ended December 31, 2017, 2016, and 2015 and was recorded as "Other income, net" in the accompanying consolidated statements of income.

As of December 31, 2017, future minimum rental income under non-cancelable operating leases as the lessor were as follows (in thousands):

Year	Total
2018	$ 4,575
2019	4,590
2020	3,978
2021	3,773
2022	3,773
Thereafter	11,127
Total	$ 31,816

7. 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 periods indicated:

	Year Ended December 31, 2017			Year Ended December 31, 2016		
	Natural Gas Transportation	Gathering, Processing & Terminalling	Total	Natural Gas Transportation	Gathering, Processing & Terminalling	Total
			(in thousands)			
Balance at beginning of period	$ 255,558	$ 87,730	$ 343,288	$ 255,558	$ 87,730	$ 343,288
Goodwill acquired	—	61,550 [1]	61,550	—	—	—
Balance at end of period	$ 255,558	$ 149,280	$ 404,838	$ 255,558	$ 87,730	$ 343,288

(1) The $61.6 million of goodwill was recorded in connection with the acquisition of a controlling interest in Deeprock Development on July 20, 2017 as discussed further in Note 3 – *Acquisitions*.

Annual Goodwill Impairment Analysis

We did not elect to apply the qualitative assessment option during our 2017 annual goodwill impairment testing; instead we proceeded directly to the quantitative impairment 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. 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 quantitative impairment test indicated no impairment as the fair value of the reporting units was greater than their respective book values. As a result, in accordance with the Codification guidance, we did not record a goodwill impairment during the year ended December 31, 2017. Unpredictable events or deteriorating market or operating conditions could result in a future change to the discounted cash flow models and cause impairments in the future. We continue to monitor potential impairment indicators to determine if a triggering event occurs and will perform additional goodwill impairment analyses as necessary.

Other Intangible Assets

A summary of amortized intangible assets is as follows:

	December 31, 2017	December 31, 2016
	(in thousands)	
Pony Express oil conversion use rights	$ 105,973	$ 105,973
Customer contracts	8,064	—
Accumulated amortization	(16,306)	(12,451)
Intangible assets, net	$ 97,731	$ 93,522

Amortization of intangible assets was approximately $3.8 million, $3.0 million, and $8.0 million for the years ended December 31, 2017, 2016, and 2015, respectively.

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

Year	Total
2018	$ 4,581
2019	4,048
2020	3,868
2021	3,868
2022	3,868
Thereafter	77,498
Total	$ 97,731

8. Investments in Unconsolidated Affiliates

Rockies Express

Our investment in Rockies Express is recorded under the equity method of accounting and is reported as "Unconsolidated investments" on our consolidated balance sheets. As of May 6, 2016, the difference between the fair value of our 25% membership interest in Rockies Express of $436.0 million and the book value of the underlying net assets resulted in a negative basis difference of approximately $404.7 million. As discussed in Note 3 – *Acquisitions*, we acquired an additional 24.99% membership interest in Rockies Express from TD on March 31, 2017. As of March 31, 2017, the negative basis difference carried over from TD from the transfer of the 24.99% Rockies Express membership interest was approximately $386.8 million. The transfer of the 24.99% Rockies Express membership interest between TD and the Partnership is considered a transaction between entities under common control, but does not represent a change in reporting entity. As a result of the common control nature of the transaction, the 24.99% membership interest in Rockies Express was transferred to the Partnership at TD's historical carrying amount, including the remaining unamortized basis difference driven by the difference between the fair value of the investment and the book value of the underlying assets and liabilities on November 13, 2012, the date of acquisition by TD.

The basis difference was allocated to property, plant and equipment and long-term debt based on their respective fair values at the date of acquisition. The amount of the basis difference allocated to property, plant and equipment is accreted over 35 years, which equates to the 2.86% composite depreciation rate utilized by Rockies Express to depreciate the underlying property, plant and equipment. The amount allocated to long-term debt is amortized over the remaining life of the various debt facilities. At December 31, 2017, the basis difference for the membership interests acquired in May 2016 and March 2017 were allocated as follows:

	Basis Difference	Amortization Period
	(in thousands)	
Long-term debt	$ 29,458	2 - 25 years
Property, plant and equipment	(788,631)	35 years
Total basis difference	$ (759,173)	

During the year ended December 31, 2017, we recognized equity in earnings associated with our 49.99% membership interest in Rockies Express of $235.6 million, inclusive of the amortization of the negative basis difference, and received distributions from and made contributions to Rockies Express of $304.7 million and $39.3 million, respectively.

Deeprock Development

As discussed in Note 3 – *Acquisitions,* on July 20, 2017, we acquired an additional 40% membership interest in Deeprock Development. As a result of the acquisition, TEP consolidated Deeprock Development and effective July 20, 2017 no longer accounts for its investment in Deeprock Development under the equity method of accounting.

Summarized Financial Information of Unconsolidated Affiliates

Combined summarized financial information for all our unconsolidated affiliates is shown in the tables below. Summarized financial information for Deeprock Development is presented from January 1, 2015 to July 20, 2017, the date TEP acquired a controlling interest in Deeprock Development. Summarized financial information for Rockies Express is presented from the date of the initial acquisition of May 6, 2016 to December 31, 2017. Summarized financial information for BNN Colorado is presented from the date of the acquisition, June 23, 2017 to December 31, 2017.

	December 31, 2017	December 31, 2016
	(in thousands)	
Current assets	$ 122,362	$ 199,958
Noncurrent assets	$ 5,974,926	$ 6,148,203
Current liabilities	$ 714,037	$ 197,305
Noncurrent liabilities	$ 2,049,189	$ 2,656,836
Members' equity	$ 3,334,062	$ 3,494,020

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Revenue	$ 860,115	$ 440,838	$ 18,646
Operating income	$ 480,337	$ 203,801	$ 13,794
Net income to Members	$ 465,592	$ 184,314	$ 13,794

9. Risk Management

We 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 crude oil and natural gas include, among others (i) pre-existing or anticipated physical crude oil and 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.

Fair Value of Derivative Contracts

The following table summarizes the fair values of our derivative contracts included in the consolidated balance sheets:

	Balance Sheet Location	December 31, 2017	December 31, 2016
		(in thousands)	
Call option derivative [1]	Current assets	$ —	$ 10,676
Natural gas derivative contracts [2]	Current assets	$ —	$ 291
Crude oil derivative contracts [3]	Current liabilities	$ 2,368	$ 440
Natural gas derivative contracts [2]	Current liabilities	$ —	$ 116

(1) As discussed below, in conjunction with our acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016, TD granted us an 18 month call option covering the 6,518,000 common units issued to TD. As of February 1, 2017, no common units remained subject to the call option.

(2) As of December 31, 2017, there were no natural gas derivative contracts outstanding. As of December 31, 2016, the fair value shown for natural gas derivative contracts was comprised of derivative volumes for short and long natural gas fixed-price swaps totaling 0.3 Bcf and 0.4 Bcf, respectively.

(3) As of December 31, 2017, the fair value shown for crude oil derivative contracts represents the forward sale of 356,000 barrels which will settle throughout the first quarter of 2018. As of December 31, 2016, the fair value shown for crude oil derivative contracts represents the sale of 125,000 barrels of crude oil which settled throughout 2017.

Effect of Derivative Contracts in the Statements of Income

The following table summarizes the impact of derivative contracts not designated as hedging contracts for the years ended December 31, 2017, 2016 and 2015:

	Location of gain (loss) recognized in income on derivatives	Amount of gain (loss) recognized in income on derivatives		
		Year Ended December 31,		
		2017	2016	2015
		(in thousands)		
Derivatives not designated as hedging contracts:				
Crude oil derivative contracts	Sales of natural gas, NGLs, and crude oil	$ 39	$ (40)	$ —
Natural gas derivative contracts	Sales of natural gas, NGLs, and crude oil	$ 75	$ 74	$ 427
Call option derivative	Unrealized gain (loss) on derivative instrument	$ 1,885	$ (1,291)	$ —

Call Option Derivative

As part of our acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016, TD granted us an 18 month call option at an exercise price of $42.50 per common unit covering the 6,518,000 common units issued to TD as a portion of the consideration. In July 2016 and October 2016, we partially exercised the call option covering 3,563,146 and 1,251,760 common units, respectively, for cash payments of $151.4 million and $53.2 million, respectively. On February 1, 2017, we exercised the remainder of the call option covering an additional 1,703,094 common units for a cash payment of $72.4 million. These common units were deemed canceled upon the exercise of the call option and as of the applicable exercise date were no longer issued and outstanding.

Credit Risk

We have counterparty credit risk as a result of our use of derivative contracts. Counterparties to our commodity derivatives consist of market participants and major financial institutions. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. The counterparty to our call option derivative was TD.

Our derivative contracts are entered into with counterparties through central trading organizations such as futures, options or stock exchanges or counterparties outside of central trading organizations. While we typically enter into derivative transactions with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future. As of December 31, 2017, the fair value of our crude oil derivative contracts were in a liability position, resulting in no credit exposure from TEP's counterparties as of that date.

As of December 31, 2017, we had $3.0 million of cash in margin accounts and outstanding letters of credit in support of our commodity derivative contracts. As of December 31, 2016, we did not have any outstanding letters of credit or cash in margin accounts in support of our hedging of commodity price risks associated with our commodity derivative contracts.

Fair Value

Derivative assets and liabilities are measured and reported at fair value. Derivative contracts can be exchange-traded or over-the-counter ("OTC"). OTC commodity 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. The call option granted by TD was valued using a Black-Scholes option pricing model. Key inputs to the valuation model included the term of the option, risk free rate, the exercise price and current market price, expected volatility and expected distribution yield of the underlying units. The call option valuation was classified within Level 2 of the fair value hierarchy as the value was based on significant observable inputs.

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

The following table summarizes the fair value measurements of our derivative contracts as of December 31, 2017 and 2016, based on the fair value hierarchy:

		Asset Fair Value Measurements Using		
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
		(in thousands)		
As of December 31, 2016:				
Call option derivative	$ 10,676	$ —	$ 10,676	$ —
Natural gas derivative contracts	$ 291	$ —	$ 291	$ —

		Liability Fair Value Measurements Using		
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
		(in thousands)		
As of December 31, 2017:				
Crude oil derivative contracts	$ 2,368	$ —	$ 2,368	$ —
As of December 31, 2016:				
Crude oil derivative contracts	$ 440	$ —	$ 440	$ —
Natural gas derivative contracts	$ 116	$ —	$ 116	$ —

10. Long-term Debt

Long-term debt consisted of the following at December 31, 2017 and 2016:

	December 31, 2017	December 31, 2016
	(in thousands)	
Revolving credit facility	$ 661,000	$ 1,015,000
5.50% senior notes due September 15, 2024	750,000	400,000
5.50% senior notes due January 15, 2028	750,000	—
Less: Deferred financing costs, net [1]	(17,737)	(7,019)
Plus: Unamortized premium on 2028 Notes	3,730	—
Total long-term debt, net	$ 2,146,993	$ 1,407,981

(1) Deferred financing costs, net as presented above relate solely to the 2024 and 2028 Notes. Deferred financing costs associated with our revolving credit facility are presented in noncurrent assets on our consolidated balance sheets.

Senior Unsecured Notes due 2028

On September 15, 2017, TEP and Tallgrass Energy Finance Corp. (the "Co-Issuer" and together with TEP, the "Issuers"), the Guarantors named therein and U.S. Bank, National Association, as trustee, entered into an Indenture dated September 15, 2017 (the "2028 Indenture") pursuant to which the Issuers issued $500 million in aggregate principal amount of 5.50% senior notes due 2028 (the "2028 Notes"). On December 11, 2017, the Issuers issued an additional $250 million in aggregate principal amount of the 2028 Notes, which are also governed by the 2028 Indenture. The notes issued on September 15, 2017 and December 11, 2017 are treated as a single class of debt securities and have identical terms, other than the issue date, offering price and first interest payment date.

The 2028 Indenture contains covenants that, among other things, limit TEP's ability and the ability of its restricted subsidiaries to: (i) create liens to secure indebtedness; (ii) enter into sale-leaseback transactions; and (iii) consolidate with or merge with or into, or sell substantially all TEP’s properties to, another person. As of December 31, 2017, we are in compliance with the covenants required under the 2028 Notes.

Senior Unsecured Notes due 2024

On September 1, 2016, the Issuers, the Guarantors named therein and U.S. Bank, National Association, as trustee, entered into an Indenture dated September 1, 2016 (the "2024 Indenture"), pursuant to which the Issuers issued $400 million in aggregate principal amount of 5.50% senior notes due 2024 (the "2024 Notes"). On May 16, 2017, the Issuers issued an additional $350 million in aggregate principal amount of the 2024 Notes, which are also governed by the 2024 Indenture. The notes issued on September 1, 2016 and May 16, 2017 are treated as a single class of debt securities and have identical terms, other than the issue date, offering price and first interest payment date.

The 2024 Indenture contains covenants that, among other things, limit TEP's ability and the ability of its restricted subsidiaries to: (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) pay distributions on equity interests in the event of default or noncompliance with the covenants required, repurchase equity securities or redeem subordinated securities; (iv) make investments; (v) restrict distributions, loans or other asset transfers from TEP's restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of TEP's properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; and (viii) enter into transactions with affiliates. As of December 31, 2017, we are in compliance with the covenants required under the 2024 Notes.

Revolving Credit Facility

On June 2, 2017, TEP entered into a $1.75 billion Second Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as administrative agent and collateral agent, and a syndicate of lenders (the "Amended Credit Agreement"). The Amended Credit Agreement amends and restates TEP's existing revolving credit facility. The Amended Credit Agreement, among other things, extends the maturity date of TEP's existing revolving credit facility from May 13, 2018 to June 2, 2022, and provides for an uncommitted accordion in an amount up to an additional $250 million, subject to the satisfaction of certain other conditions. In addition, the revolving credit facility includes a $60 million sublimit for swing line loans and a $75 million sublimit for letters of credit

The following table sets forth the available borrowing capacity under the revolving credit facility as of December 31, 2017 and 2016:

	December 31, 2017	December 31, 2016
	(in thousands)	
Total capacity under the revolving credit facility	$ 1,750,000	$ 1,750,000
Less: Outstanding borrowings under the revolving credit facility	(661,000)	(1,015,000)
Less: Letters of credit issued under the revolving credit facility	(94)	—
Available capacity under the revolving credit facility	$ 1,088,906	$ 735,000

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 therefrom, 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 5.00 to 1.00 (which will be increased to 5.50 to 1.00 for certain measurement periods following the consummation of certain acquisitions), a consolidated senior secured leverage ratio of not more than 3.75 to 1.00 and a consolidated interest coverage ratio of not less than 2.50 to 1.00. As of December 31, 2017, 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 0.250% to 0.500%, based on our total leverage ratio. As of December 31, 2017, the weighted average interest rate on outstanding borrowings under the revolving credit facility was 3.24%. During the year ended December 31, 2017, our weighted average effective interest rate, including the interest on outstanding borrowings under the revolving credit facility, commitment fees, and amortization of deferred financing costs, was 3.31%.

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, 2017 and 2016, 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)			
As of December 31, 2017:					
Revolving credit facility	$ —	$ 661,000	$ —	$ 661,000	$ 661,000
2024 Notes	$ —	$ 771,645	$ —	$ 771,645	$ 739,824
2028 Notes	$ —	$ 758,168	$ —	$ 758,168	$ 746,169
As of December 31, 2016:					
Revolving credit facility	$ —	$ 1,015,000	$ —	$ 1,015,000	$ 1,015,000
2024 Notes	$ —	$ 398,000	$ —	$ 398,000	$ 392,981

The long-term debt borrowed under the revolving credit facility is carried at amortized cost. As of December 31, 2017 and 2016, the fair value of borrowings under the revolving credit facility approximates the carrying amount of the borrowings using a discounted cash flow analysis. The 2024 and 2028 Notes are carried at amortized cost, net of deferred financing costs. The estimated fair value of the 2024 and 2028 Notes is based upon quoted market prices adjusted for illiquid markets. We are not aware of any factors that would significantly affect the estimated fair value subsequent to December 31, 2017.

11. Partnership Equity and Distributions

Equity Distribution Agreements

We have active equity distribution agreements 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 $100.2 million and $657.5 million. Net cash proceeds from any sale of the common units may be used for general partnership purposes, which includes, among other things, the Partnership's exercise of the call option with respect to the 6,518,000 common units issued to TD in connection with the Partnership's acquisition of an additional 31.3% of Pony Express in January 2016, repayment or refinancing of debt, funding for acquisitions, capital expenditures and additions to working capital.

During the year ended December 31, 2017, we issued and sold 2,341,061 common units with a weighted average sales price of $48.82 per unit under our equity distribution agreements for net cash proceeds of approximately $112.4 million (net of approximately $1.9 million in commissions and professional service expenses). We used the net cash proceeds for general partnership purposes as described above.

During the year ended December 31, 2016, we issued and sold 7,696,708 common units with a weighted average sales price of $44.46 per unit under our equity distribution agreement for net cash proceeds of approximately $337.7 million (net of approximately $4.5 million in commissions and professional service expenses). We used the net cash proceeds for general partnership purposes as described above.

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 agreements for net cash proceeds of approximately $3.0 million (net of approximately $30,000 in commissions and professional service expenses). We used the net cash proceeds for general partnership purposes as described above.

Repurchase of Common Units Owned by TD

Following an offer received from TD with respect to common units owned by TD not subject to the call option, we repurchased 736,262 common units from TD at an aggregate price of approximately $35.3 million, or $47.99 per common unit, on February 1, 2017, which was approved by the conflicts committee of the board of directors of our general partner. These common units were deemed canceled upon our purchase and as of such transaction date were no longer issued and outstanding.

Private Placement

On April 28, 2016, we issued an aggregate of 2,416,987 common units for net cash proceeds of $90 million in a private placement transaction to certain funds managed by Tortoise Capital Advisors, L.L.C. The units were subsequently registered pursuant to our Form S-3/A (File No. 333-210976) filed with the SEC on May 6, 2016, which became effective May 17, 2016.

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 at the time of the announcement had authorized an equity purchase program under which TD could purchase up to an aggregate of $100 million of the outstanding Class A shares of TEGP or the outstanding common units of TEP on the open market or in negotiated purchases. No purchases were made under this program during the years ended December 31, 2017 and 2016, nor during the period commencing January 1, 2018 and prior to the merger of TD into Tallgrass Development Holdings on February 7, 2018. As a result of such merger, no future purchases are expected to be made under the program.

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 3 - *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 3 - *Acquisitions*.

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

Our partnership agreement requires us to distribute our available cash, as defined in the partnership agreement, 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 Unit
			General Partner			
		Limited Partner Common Units	Incentive Distribution Rights	General Partner Units	Total	
			(in thousands, except per unit amounts)			
December 31, 2017	February 14, 2018 [1]	$ 70,638	$ 39,125	$ 1,251	$ 111,014	$ 0.9650
September 30, 2017	November 14, 2017	69,174	37,744	1,219	108,137	0.9450
June 30, 2017	August 14, 2017	67,671	36,342	1,186	105,199	0.9250
March 31, 2017	May 15, 2017	60,486	29,840	1,040	91,366	0.8350
December 31, 2016	February 14, 2017	58,793	28,358	1,008	88,159	0.8150
September 30, 2016	November 14, 2016	57,332	26,987	976	85,295	0.7950
June 30, 2016	August 12, 2016	54,442	24,262	911	79,615	0.7550
March 31, 2016	May 13, 2016	48,238	19,816	830	68,884	0.7050
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

(1) The distribution announced on January 8, 2018 for the fourth quarter of 2017 will be paid on February 14, 2018 to unitholders of record at the close of business on January 31, 2018.

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, 2017, the general partner owns an approximate 1.13% 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 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 the IDRs.

If for any quarter:

- We have distributed available cash from operating surplus to all 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.

<u>Definition of Available Cash</u>

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, 2017, TEP recognized the following other contributions and distributions:

- TEP was deemed to have made a noncash capital distribution of $57.7 million to the general partner, which represents the excess purchase price over the carrying value of the Terminals and NatGas net assets acquired January 1, 2017;
- TEP was deemed to have made a noncash capital distribution of $12.6 million to the general partner, which represents the derecognition of a portion of the derivative asset associated with the partial exercise of the call option;
- TEP was deemed to have received a noncash capital contribution of $63.7 million from the general partner, which represents the excess carrying value of the additional 24.99% membership interest in Rockies Express acquired March 31, 2017 over the fair value of the consideration paid;
- TEP received contributions from TD of $2.3 million primarily to indemnify TEP for costs associated with Trailblazer's Pipeline Integrity Management Program, as discussed in Note 17 – *Legal and Environmental Matters*; and
- TEP recognized contributions from and distributions to noncontrolling interests of $1.6 million, and $6.2 million, respectively, which primarily consisted of activity associated with TD's 2% noncontrolling interest in Pony Express.

During the year ended December 31, 2016, TEP recognized the following other contributions and distributions:

- TEP was deemed to have made noncash capital distributions of $280.0 million and $34.0 million to the general partner, which represent the excess purchase price over the carrying value of the additional 31.3% membership interest in Pony Express acquired effective January 1, 2016 and the derecognition of a portion of the derivative asset associated with the partial exercise of the call option, respectively;
- TEP received contributions of $17.9 million from TD to indemnify TEP for costs associated with Trailblazer's Pipeline Integrity Management Program, as discussed above; and
- TEP recognized contributions from and distributions to noncontrolling interests of $9.3 million and $6.5 million, respectively, which primarily consisted of activity associated with TD's 2% noncontrolling interest in Pony Express.

During the year ended December 31, 2015, TEP recognized the following other contributions and distributions:

- 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; and
- TEP 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.

12. Commitments & Contingent Liabilities

Leases

Rent expense under operating leases and right of way agreements totaled approximately $9.5 million, $16.5 million, and $16.1 million for the years ended December 31, 2017, 2016, and 2015, respectively.

At December 31, 2017, future minimum rental commitments under major, non-cancelable operating leases were as follows (in thousands):

Year	Total
2018	$ 1,226
2019	1,351
2020	1,414
2021	1,093
2022	828
Thereafter	4,394
Total	$ 10,306

Operating leases consist of leases for office space and equipment. Prior to the acquisition of a controlling interest in Deeprock Development in July 2017, as discussed in as discussed in Note 3 - *Acquisitions*, rent expense included payments made by Pony Express to Deeprock Development for the use by Pony Express of storage capacity at the Deeprock tank storage facility near Cushing, Oklahoma.

Capital Expenditures

We had committed approximately $17.3 million for the future purchase of property, plant and equipment at December 31, 2017.

Other Purchase Obligations

Other purchase obligations primarily represent costs associated with Western's freshwater delivery and produced water gathering and disposal systems acquired in December 2015. Actual costs associated with these contracts totaled approximately $2.5 million, $1.4 million, and $4,000 for the years ended December 31, 2017, 2016, and 2015, respectively.

At December 31, 2017, future minimum commitments under long-term, non-cancelable contracts for other purchase obligations were as follows (in thousands):

Year	Total
2018	$ 2,084
2019	2,091
2020	2,070
2021	20
2022	20
Thereafter	48
Total	$ 6,333

13. Net Income per Limited Partner Unit

The Partnership's net income is allocated to the general partner and the limited partners in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner.

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.

All net income or loss from Terminals and NatGas prior to our acquisition on January 1, 2017 is allocated to predecessor operations in the consolidated statements of income and in the table below. Historical earnings of transferred businesses for periods prior to the date of those common control 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 unitholders. We present the financial results of any transferred business prior to the transaction date in the line item "Predecessor operations interest in net income" in the consolidated statements of income and in the table below.

The following table illustrates the calculation of net income per common unit for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
	(in thousands, except per unit amounts)		
Net income	$ 440,489	$ 274,889	$ 197,171
Net income attributable to noncontrolling interests	(6,499)	(4,365)	(24,268)
Net income attributable to partners	433,990	270,524	172,903
Predecessor operations interest in net income	—	(6,995)	(12,357)
General partner interest in net income	(147,823)	(102,465)	(46,478)
Net income available to common unitholders	$ 286,167	$ 161,064	$ 114,068
Basic net income per common unit	$ 3.93	$ 2.26	$ 1.95
Diluted net income per common unit	$ 3.90	$ 2.23	$ 1.91
Basic average number of common units outstanding	72,876	71,150	58,597
Equity Participation Unit equivalent units	582	957	978
Diluted average number of common units outstanding	73,458	72,107	59,575

14. Major Customers and Concentration of Credit Risk

During the year ended December 31, 2017 one non-affiliated customer, Continental Resources, Inc. ("Continental Resources"), accounted for $100.2 million (15%) of our total operating revenue. During the year ended December 31, 2016 two non-affiliated customers, Continental Resources and Shell Trading (US) Company ("Shell"), accounted for $97.8 million (16%) and $76.2 million (12%) of our total operating revenues, respectively. 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 (14%) of our total operating revenues, respectively. Revenues from Continental Resources for the years ended December 31, 2017, 2016, and 2015 were earned in our Crude Oil Transportation segment. Revenues from Shell for the years ended December 31, 2016 and 2015 were earned in our Natural Gas Transportation, Crude Oil Transportation, and Gathering, Processing & Terminalling segments.

For the year ended December 31, 2017, the percentage of segment revenues from the top ten non-affiliated customers for each segment was as follows:

	Percentage of Segment Revenue
Natural Gas Transportation	56%
Crude Oil Transportation	91%
Gathering, Processing & Terminalling	75%

We attempt to mitigate credit risk by seeking credit support, such as letters of credit, prepayments or other financial guarantees from customers with specific credit concerns. In support of credit extended to certain customers, we had received prepayments of $4.9 million at December 31, 2017 and 2016, 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. Vesting and forfeiture requirements are at the discretion of the board of directors of the general partner (the "Board") and can be delegated to a committee of the Board.

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 or a committee thereof, which is referred to as the plan administrator.

The Board may generally terminate or amend the LTIP at any time with respect to any units for which a grant has not yet been made. The Board 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 Board or (iii) May 13, 2023.

Equity Participation Units

The Board has previously approved the grant of up to 1.9 million equity participation units ("EPUs") for issuance to employees and 302,500 EPUs to certain Section 16 officers under the LTIP. 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 $10.4 million, $7.9 million, and $9.3 million for the years ended December 31, 2017, 2016, and 2015, respectively. Of the total compensation cost, $8.7 million, $5.8 million, and $5.1 million for the years ended December 31, 2017, 2016, and 2015, respectively, was recognized as compensation expense at TEP and the remainder was allocated to TD. As of December 31, 2017, $24.6 million of total compensation cost related to non-vested EPUs is expected to be recognized over a weighted average period of 2.7 years, a portion of which was charged to TD. Following the merger of TD into a subsidiary of Tallgrass Equity, such costs will be allocated to Tallgrass Energy Holdings and its affiliates going forward.

The following table summarizes the changes in the EPUs outstanding for the years ended December 31, 2017, 2016 and 2015:

	Equity Participation Units	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2015	1,525,750	$ 18.75
Granted	338,591	40.01
Vested [(1)]	(480,555)	(19.39)
Forfeited	(58,825)	(16.98)
Outstanding at December 31, 2015	1,324,961	24.11
Granted	94,750	35.12
Vested [(1)]	(35,998)	(23.74)
Forfeited	(43,829)	(20.08)
Outstanding at December 31, 2016	1,339,884	24.92
Granted	621,400	38.58
Vested [(1)]	(941,858)	(19.70)
Forfeited	(30,033)	(39.08)
Outstanding at December 31, 2017	989,393	$ 38.58

(1) During the years ended December 31, 2017, 2016, and 2015, approximately 683,304, 24,933, and 344,383 common units (net of tax withholding of approximately 258,554, 11,065, and 136,172 common units) were issued in connection with the settlement of vested awards, respectively.

16. Regulatory Matters

There are no regulatory proceedings challenging the rates of Pony Express, Rockies Express, Tallgrass Interstate Gas Transmission, LLC ("TIGT") or Trailblazer Pipeline Company LLC ("Trailblazer"). We have made certain regulatory filings with the FERC, including the following:

Pony Express

On May 25, 2016, Pony Express made a tariff filing with the FERC in Docket No. IS16-326-000 to update its non-contract rates under its Local Pipeline Tariff for local non-contract rates from all origins, by an amount reflecting the most recent FERC annual index adjustment of approximately 0.9799 effective July 1, 2016, which resulted in a reduction of the Pony Express non-contract rates of 2.01%.

On May 22, 2017 and May 31, 2017, Pony Express made tariff filings with the FERC in Docket Nos. IS17-263-000, IS17-464-00, and IS17-465-000 to increase the contract and non-contract rates by an amount reflecting the most recent FERC annual index adjustment of approximately 0.2%, which became effective July 1, 2017.

On November 30, 2017, Pony Express filed with the FERC in Docket No. IS18-60-000 certain changes to its tariffs to reflect the addition of two new destination points proposed to be effective January 1, 2018.

On December 29, 2017, Pony Express filed with the FERC in Docket No. IS18-113-000 certain changes to its tariffs to reflect a new origin point in Rooks County, Kansas. The changes were proposed to become effective on February 1, 2018.

Rockies Express

Petition for Declaratory Order – FERC Docket No. RP13-969-000

In June 2013, in Docket No. RP13-969-000, Rockies Express filed with the FERC a Petition for Declaratory Order which sought a ruling that the "most favored nations" or "MFN" provisions contained in Rockies Express' negotiated rate agreements ("NRAs") with its Foundation and Anchor Shippers would not prevent Rockies Express from providing firm transportation service at rates lower than Foundation and Anchor Shippers' rates that (1) have an east-to-west primary path; (2) are for a term of one year or longer; and (3) are limited to service in one rate zone and therefore do not utilize all of the same facilities or rate zones as the service provided pursuant to the Foundation and Anchor Shipper NRAs. In November 2013, the FERC issued a declaratory order finding that the potential transactions would not trigger the MFN rights of Rockies Express' Foundation and Anchor Shippers. Various parties filed requests for rehearing of the FERC's declaratory order.

In September 2014 and December 2015, the FERC accepted amended contracts with the shippers holding MFN rights on Rockies Express, which reflect the terms of settlements between these shippers and Rockies Express. The settlements provide additional clarity with respect to the applicability of the settling shippers' MFN rights, sharing by Rockies Express of certain transportation revenues, and the withdrawal of the settling shippers from the Petition for Declaratory Order proceeding. On September 27, 2017, FERC issued an order denying the requests for rehearing of the declaratory order issued in November 2013, and no party sought judicial appeal of the FERC order denying rehearing within the statutory deadline.

2015 Annual FERC Fuel Tracking Filings - FERC Docket No. RP15-584-000

On February 27, 2015, Rockies Express made its annual fuel tracker filing with a proposed effective date of April 1, 2015 in Docket No. RP15-584-000. This filing incorporated the revised fuel and lost and unaccounted-for and power cost tracker mechanisms filed in Docket No. RP14-1003. The FERC issued an order accepting the filing on March 26, 2015 and on April 9, 2015, accepted an errata to the February 27, 2015 filing reflecting a corrected rate for the Cheyenne Booster rate (PCT Reimbursement Charge).

Seneca Lateral Facilities Conversion – FERC Docket No. CP15-102-000

On March 2, 2015 in Docket No. CP15-102-000, Rockies Express filed with the FERC an application for (1) authorization to convert certain existing and operating pipeline and compression facilities located in Noble and Monroe Counties, Ohio (Seneca Lateral Facilities described in Docket Nos. CP13-539-000 and CP14-194-000) from Natural Gas Policy Act of 1978 Section 311 authority to NGA Section 7 jurisdiction, and (2) issuance of a certificate of public convenience and necessity authorizing Rockies Express to operate and maintain the Seneca Lateral Facilities. On April 7, 2016, the FERC issued a Certificate to Rockies Express granting its requested authorizations and on June 1, 2016 Rockies Express commenced NGA service on the Seneca Lateral.

Rockies Express Zone 3 Capacity Enhancement Project – FERC Docket No. CP15-137-000

On March 31, 2015 in Docket No. CP15-137-000, Rockies Express filed with the FERC an application for authorization to construct and operate (1) three new mainline compressor stations located in Pickaway and Fayette Counties, Ohio and Decatur County, Indiana; (2) additional compressors at an existing compressor station in Muskingum County, Ohio; and (3) certain ancillary facilities. The facilities increased the Rockies Express Zone 3 east-to-west mainline capacity by 0.8 Bcf/d. Pursuant to the FERC's obligations under the National Environmental Policy Act, FERC staff issued an Environmental Assessment for the project on August 31, 2015. On February 25, 2016, the FERC issued a Certificate of Public Convenience and Necessity authorizing Rockies Express to proceed with the project. On March 14, 2016, Rockies Express commenced construction of the project facilities. The project was placed in-service for the full 0.8 Bcf/d on January 6, 2017.

2016 Annual and Interim FERC Fuel Tracking Filings - FERC Docket Nos. RP16-702 and RP17-240

On March 1, 2016, Rockies Express made its annual fuel tracker filing with a proposed effective date of April 1, 2016 in Docket No. RP16-702. The FERC issued an order accepting the filing on March 25, 2016. On December 1, 2016, Rockies Express made an interim fuel tracker filing with a proposed effective date of January 1, 2017 in Docket No. RP17-240. The FERC issued an order accepting the filing on December 29, 2016.

Electric Power Charge Clarification - FERC Docket No. RP17-285

On December 21, 2016, in Docket No. RP17-285, Rockies Express proposed certain revisions to the General Terms and Conditions of its tariff to clarify that the electric power costs associated with the operation of gas coolers installed in association with the Zone 3 Capacity Enhancement Project at both electric and gas powered stations, will be included in the Power Cost Tracker. Several shippers submitted comments on the proposal. The FERC issued an order on January 19, 2017 accepting the proposed revisions permitting the recovery of electric power costs from the operation of both gas and electric powered compressor stations, subject to certain clarifications.

2017 Annual and Interim FERC Fuel Tracking Filings - FERC Docket Nos. RP17-401 and RP17-1064

On February 13, 2017, in Docket No. RP17-401, Rockies Express made its annual fuel and power cost tracker filing with a proposed effective date of April 1, 2017. The FERC issued an order accepting the filing, including certain requested waivers, on March 21, 2017. On September 20, 2017, Rockies Express made its interim fuel tracker filing in Docket No. RP17-1064 with a proposed effective date of November 1, 2017. The FERC issued an order accepting the filing on October 18, 2017.

Increased Frequency of FL&U and PCT Adjustments - FERC Docket No. RP18-228

On December 1, 2017, in Docket No. RP18-228, Rockies Express made a filing with the FERC to increase the frequency in which it may adjust fixed fuel and lost and unaccounted for retainages and power cost tracker charges during the year so that its recovery of fixed fuel and lost and unaccounted for charges and power costs more closely track usage. Rockies Express proposed an effective date of April 1, 2018. The comment period ended on December 13, 2017, and no parties opposed Rockies Express' filing. The matter is pending before the FERC.

TIGT

General Rate Case Filing - FERC Docket No. RP16-137-000, et seq.

On October 30, 2015, in Docket No. RP16-137-000, *et seq.*, TIGT filed a general rate case with the FERC pursuant to Section 4 of the National Gas Act ("NGA"). The general rate case was ultimately resolved via settlement, which the FERC approved on November 2, 2016, and a compliance filing that modernized TIGT's FERC Gas Tariff, consistent with prior FERC orders, which the FERC accepted on March 16, 2017. Per the terms of the settlement, TIGT is required to file a new general rate case on May 1, 2019 (provided that such rate case is not pre-empted by a pre-filing settlement).

2017 Annual Fuel Tracker Filing - FERC Docket No. RP17-428-000

On February 27, 2017, in Docket No. RP17-428-000, TIGT made its annual fuel tracker filing with a proposed effective date of April 1, 2017. The filing incorporated the FL&U tracker and power cost tracker mechanisms agreed to in the TIGT Rate Case Settlement. The FERC accepted the filing on March 21, 2017.

Electric Power Charge Clarification - FERC Docket No. RP17-1051-000

On September 15, 2017, in Docket No. RP17-1051-000, TIGT proposed certain revisions to its tariff to clarify, amongst other things, that the electric power costs associated with the operation of gas coolers at both electric and gas powered stations are properly included in the Power Cost Tracker. The FERC issued an order on October 3, 2017 accepting the proposed revisions.

Trailblazer

General Rate Case Filing - FERC Docket No. RP13-1031-000, et. seq.

On July 1, 2013, in Docket No. RP13-1031-000, *et. seq.*, Trailblazer filed a general rate case with the FERC pursuant to Section 4 of the NGA. The general rate case was ultimately resolved via settlement, which the FERC approved on May 29, 2014. Per the terms of the settlement, Trailblazer is required to file a new general rate case with rates to be effective no later than January 1, 2019 (presuming a maximum suspension period for any rate increase).

2016 Annual Fuel Tracker Filing – FERC Docket Nos. RP16-814-000 and RP16-814-001

On April 1, 2016, Trailblazer made its annual fuel tracker filing with a proposed effective date of May 1, 2016 in Docket No. RP16-814-000. The FERC accepted this filing on April 18, 2016. On May 19, 2016, Trailblazer filed its refund report associated with the April 1, 2016 annual fuel tracker filing, which the FERC accepted on July 11, 2016. On September 7, 2016, Trailblazer filed an adjustment to its April 1, 2016 filing in Docket No. RP16-814-001, which the FERC accepted on October 3, 2016. Trailblazer filed a corresponding refund report on October 14, 2016, which the FERC accepted on November 16, 2016.

2017 Annual and Interim Fuel Tracker Filings - FERC Docket Nos. RP17-549-000 and RP17-1052-000

On March 22, 2017, in Docket No. RP17-549-000, Trailblazer made its annual fuel tracker filing with a proposed effective date of May 1, 2017. The FERC accepted the filing on April 19, 2017. On September 15, 2017, Trailblazer made its interim fuel tracker filing in Docket No. RP17-1052-000 with a proposed effective date of November 1, 2017. The FERC accepted the filing on October 13, 2017.

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, 2017 and 2016.

Rockies Express

Mineral Management Service Lawsuit

On June 30, 2009, Rockies Express filed claims against Mineral Management Service, a former unit of the U.S. Department of Interior (collectively "Interior") for breach of its contractual obligation to sign transportation service agreements for pipeline capacity that it had agreed to take on Rockies Express. The Civilian Board of Contract Appeals ("CBCA") conducted a trial and ruled that Interior was liable for breach of contract, but limited the damages Interior was required to pay. On September 13, 2013, the United States Court of Appeals for the Federal Circuit issued a decision affirming that Interior was liable for its breach of contract, but reversing the CBCA's decision to limit damages. The case was remanded to the CBCA for the purpose of calculating damages at a hearing. On May 20, 2016, Rockies Express and Interior agreed to resolve the claims in this matter in exchange for a $65 million cash payment to Rockies Express. Interior paid the amount due Rockies Express on June 23, 2016.

Ultra Resources

In early 2016, Ultra Resources, Inc. ("Ultra") defaulted on its firm transportation service agreement for approximately 0.2 Bcf/d through November 11, 2019. In late March 2016, Rockies Express terminated Ultra's service agreement. On April 14, 2016, Rockies Express filed a lawsuit against Ultra for breach of contract and damages in Harris County, Texas, seeking approximately $303 million in damages and other relief. On April 29, 2016, Ultra and certain of its debtor affiliates filed for protection under Chapter 11 of the United States Bankruptcy Code in United States Bankruptcy Court for the Southern District of Texas, which operated as a stay of the Harris County state court proceeding.

On January 12, 2017, Rockies Express and Ultra entered into an agreement to settle Rockies Express' approximately $303 million claim against Ultra. In accordance with the settlement agreement, Ultra made a cash payment to Rockies Express of $150 million on July 12, 2017, and entered into a new, seven-year firm transportation agreement with Rockies Express commencing December 1, 2019, for west-to-east service of 0.2 Bcf/d at a rate of approximately $0.37 per dth/d, or approximately $26.8 million annually. TEP received its proportionate distribution from the cash settlement payment in July 2017.

Michels Corporation

On June 17, 2014, Michels Corporation ("Michels") filed a complaint and request for relief against Rockies Express in the Court of Common Pleas, Monroe County, Ohio, as a result of work performed by Michels to construct the Seneca Lateral Pipeline in Ohio. Michels sought unspecified damages from Rockies Express and asserted claims of breach of contract, negligent misrepresentation, unjust enrichment and quantum meruit. Michels also filed notices of Mechanic's Liens in Monroe and Noble Counties, asserting $24.2 million as the amount due.

On February 2, 2017, Rockies Express and Michels agreed to resolve Michels' claims for a $10 million cash payment by Rockies Express. The cash payment was inclusive of approximately $5.9 million that Rockies Express had been withholding from Michels. Subsequently, Rockies Express and Michels entered into a definitive agreement with respect to the settlement and Rockies Express made the $10 million cash payment to Michels on February 16, 2017.

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 $7.7 million and $4.0 million at December 31, 2017 and 2016, respectively.

TMID

Casper Plant, EPA Notice of Violation

In August 2011, the 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 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 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. Settlement negotiations are continuing, including 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. On July 3, 2017, our partial delisting request was published by the EPA in the Federal Register. On August 3, 2017, there were no adverse public comments, therefore on August 29, 2017, the Casper Gas Plant portion of the Casper Mystery Bridge Superfund Site was 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.

TMG

Archibald Booster Station

Tallgrass Midstream Gathering, LLC ("TMG") is currently a party to a remedy agreement entered into with the WDEQ in July 2013 with respect to the Archibald Booster Station located in Campbell County, Wyoming. In connection with the remedy agreement, TMG has agreed to complete certain remedial actions at the site related to a former earthen pit including semi-annual groundwater sampling, and quarterly recovery activities at monitoring wells. The facility is currently in compliance with the WDEQ under the remedy agreement.

Irwin Booster Station

TMG is also party to a remedy agreement entered into with the WDEQ in July 2013 with respect to the Irwin Booster Station located in Converse County, Wyoming. In connection with the remedy agreement, TMG has agreed to complete certain remedial actions at the site related to a former earthen pit including semi-annual groundwater sampling. The facility is currently in compliance with the WDEQ under the remedy agreement.

Trailblazer

Pipeline Integrity Management Program

Starting in 2014 Trailblazer's operating capacity was decreased as a result of smart tool surveys that identified approximately 25 - 35 miles of pipe as potentially requiring repair or replacement. During 2016 and 2017, Trailblazer incurred approximately $21.8 million of remediation costs to address this issue, including replacing approximately 8 miles of pipe. To date the pressure and capacity reduction has not prevented Trailblazer from fulfilling its firm service obligations at existing subscription levels or had a material adverse financial impact on us. However, Trailblazer intends to continue performing remediation to increase and maximize its operating capacity over the long-term and expects to spend in excess of $20 million during 2018 for this pipe replacement and remediation work. Trailblazer is exploring all possible cost recovery options to recover expenditures, including recovery through a general rate increase, negotiated rate agreements with its customers, or other FERC-approved recovery mechanisms.

In connection with our acquisition of Trailblazer in April 2014, TD agreed to indemnify TEP for certain out of pocket costs related to repairing or remediating the Trailblazer Pipeline. The contractual indemnity was capped at $20 million and subject to a $1.5 million deductible. TEP has received the entirety of the $20 million from TD pursuant to the contractual indemnity as of December 31, 2017.

Pony Express

Pipeline Integrity

In connection with certain crack tool runs on the Pony Express System completed in 2015 and 2016, Pony Express completed approximately $10 million of remediation for anomalies identified on the Pony Express System associated with the initial conversion and commissioning of portions of the pipeline converted from natural gas to crude oil service, and has completed additional remediation on the Pony Express System of approximately $8.2 million during the year ended December 31, 2017.

Terminals

System Failures

In January 2017, approximately 10,000 bbls of crude oil were released at the Sterling Terminal as the result of a defective roof drain system on a storage tank. The release was restricted to the containment area designed for such purpose and approximately 9,000 bbls were recovered. Remediation was complete as of June 30, 2017. The total cost to remediate the release was approximately $600,000.

18. Reportable Segments

Our operations are located in the United States. During the third quarter of 2017, management revised the operational reporting used by the chief operating decision maker in light of recent acquisitions and commercial management reorganization. As a result of this internal change, our reportable segments were updated to ensure that segment classification remains aligned with operational reporting. We are organized into three reportable segments: (1) Natural Gas Transportation, (2) Crude Oil Transportation, and (3) Gathering, Processing & Terminalling.

Natural Gas Transportation

The Natural Gas Transportation segment is engaged in the ownership and operation of FERC-regulated interstate natural gas pipelines and an integrated natural gas storage facility that provides services to on-system customers (such as third-party LDCs), industrial users and other shippers. The Natural Gas Transportation segment includes our 100% membership interest in NatGas acquired effective January 1, 2017 and our 49.99% membership interest in Rockies Express, including the additional 24.99% membership interest acquired effective March 31, 2017.

Crude Oil Transportation

The Crude Oil Transportation 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, Denver-Julesburg and Powder River Basins, 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.

Gathering, Processing & Terminalling

The Gathering, Processing & Terminalling segment is engaged in the ownership and operation of natural gas gathering and processing facilities that produce NGLs and residue gas that is sold in local wholesale markets or delivered into pipelines for transportation to additional end markets, including the Douglas Gathering System acquired on June 5, 2017, as well as water business services provided primarily to the oil and gas exploration and production industry and the transportation of NGLs. The Gathering, Processing & Terminalling segment also includes Stanchion as well as our 100% membership interest in Terminals acquired effective January 1, 2017 and the PRB Crude System acquired on August 3, 2017.

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 and the 2024 and 2028 Notes, public company costs, 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:

Revenue:	2017 Total Revenue	2017 Inter-Segment	2017 External Revenue	2016 Total Revenue	2016 Inter-Segment	2016 External Revenue	2015 Total Revenue	2015 Inter-Segment	2015 External Revenue
	(in thousands)								
Natural Gas Transportation	$141,021	$ (6,694)	$134,327	$135,097	$ (5,641)	$129,456	$137,988	$ (5,384)	$132,604
Crude Oil Transportation	364,574	(10,676)	353,898	380,503	(370)	380,133	304,227	—	304,227
Gathering, Processing & Terminalling	186,211	(18,538)	167,673	113,533	(11,460)	102,073	113,387	(7,557)	105,830
Corporate and Other	—	—	—	—	—	—	—	—	—
Total revenue	$691,806	$(35,908)	$655,898	$629,133	$(17,471)	$611,662	$555,602	$(12,941)	$542,661

Adjusted EBITDA:	2017 Total Adjusted EBITDA	2017 Inter-Segment	2017 External Adjusted EBITDA	2016 Total Adjusted EBITDA	2016 Inter-Segment	2016 External Adjusted EBITDA	2015 Total Adjusted EBITDA	2015 Inter-Segment	2015 External Adjusted EBITDA
	(in thousands)								
Natural Gas Transportation	$392,394	$ (7,709)	$384,685	$154,850	$ (5,641)	$149,209	$ 73,699	$ (5,384)	$ 68,315
Crude Oil Transportation	243,106	17,263	260,369	264,391	16,843	281,234	165,204	12,941	178,145
Gathering, Processing & Terminalling	50,970	(9,554)	41,416	17,928	(11,202)	6,726	32,243	(7,557)	24,686
Corporate and Other	(8,463)	—	(8,463)	(4,622)	—	(4,622)	(2,979)	—	(2,979)
Reconciliation to Net Income:									
Add:									
Equity in earnings of unconsolidated investments			237,110			54,531			2,759
Gain on remeasurement of unconsolidated investment			9,728			—			—
Non-cash loss allocated to noncontrolling interest			—			—			9,377
Less:									
Interest expense, net of noncontrolling interest			(83,542)			(40,688)			(15,517)
Depreciation and amortization expense, net of noncontrolling interest			(92,455)			(88,122)			(77,111)
Distributions from unconsolidated investments			(306,626)			(78,568)			(4,648)

Non-cash loss related to derivative instruments, net of noncontrolling interests	(226)	(1,547)	—
Non-cash compensation expense	(8,660)	(5,780)	(5,103)
Gain (loss) on disposal of assets, net of noncontrolling interests	654	(1,849)	(4,795)
Loss on extinguishment of debt	—	—	(226)
Net income attributable to partners	$433,990	$270,524	$172,903

	Year Ended December 31,		
Capital Expenditures:	2017	2016	2015
		(in thousands)	
Natural Gas Transportation	$ 16,705	$ 28,475	$ 10,478
Crude Oil Transportation	57,022	29,893	38,802
Gathering, Processing & Terminalling	71,417	26,123	71,438
Corporate and Other	—	—	—
Total capital expenditures	$ 145,144	$ 84,491	$ 120,718

Unconsolidated Investments:	December 31, 2017	December 31, 2016
	(in thousands)	
Natural Gas Transportation	$ 895,873	$ 461,915
Crude Oil Transportation	—	—
Gathering, Processing & Terminalling	13,658	13,710
Corporate and Other	—	—
Total unconsolidated investments	$ 909,531	$ 475,625

Assets:	December 31, 2017	December 31, 2016
	(in thousands)	
Natural Gas Transportation	$ 1,606,666	$ 1,176,147
Crude Oil Transportation	1,407,758	1,410,695
Gathering, Processing & Terminalling	943,340	495,170
Corporate and Other	19,589	20,201
Total assets	$ 3,977,353	$ 3,102,213

19. Selected Quarterly Financial Data (Unaudited)

The following tables summarize our unaudited quarterly financial data for 2017 and 2016:

	Quarter Ended 2017			
	First	Second	Third	Fourth
	(in thousands, except per unit amounts)			
Total revenues	$ 144,400	$ 160,863	$ 175,869	$ 174,766
Operating income	$ 63,780	$ 67,504	$ 74,567	$ 68,236
Net income	$ 71,784	$ 90,829	$ 185,503	$ 92,373
Net income attributable to partners	$ 70,905	$ 89,880	$ 184,090	$ 89,115
Net income available to common unitholders	$ 40,322	$ 52,579	$ 144,281	$ 48,985
Basic net income per limited partner unit	$ 0.56	$ 0.72	$ 1.97	$ 0.67
Diluted net income per limited partner unit	$ 0.55	$ 0.72	$ 1.96	$ 0.67

During the third quarter of 2017, we recognized equity in earnings relating to our proportionate share of the Ultra settlement discussed in Note 17 – *Legal and Environmental Matters.*

	Quarter Ended 2016			
	First	Second	Third	Fourth
	(in thousands, except per unit amounts)			
Total revenues	$ 147,168	$ 149,015	$ 153,268	$ 162,211
Operating income	$ 63,966	$ 55,307	$ 67,511	$ 73,830
Net income	$ 48,796	$ 89,270	$ 65,429	$ 71,394
Net income attributable to partners	$ 47,755	$ 88,160	$ 64,345	$ 70,264
Net income available to common unitholders	$ 23,717	$ 66,728	$ 33,060	$ 37,559
Basic net income per limited partner unit	$ 0.35	$ 0.93	$ 0.45	$ 0.52
Diluted net income per limited partner unit	$ 0.35	$ 0.92	$ 0.45	$ 0.51

20. Subsequent Events

Deeprock North Acquisition and Merger with Deeprock Development

On January 2, 2018, Terminals acquired an approximate 38% membership interest in Deeprock North, LLC ("Deeprock North") from Kinder Morgan Deeprock North Holdco LLC for cash consideration of $19.5 million. Immediately following the acquisition, Deeprock North was merged into Deeprock Development. After the acquisition and merger, Terminals owns an approximately 60% membership interest in the combined entity.

BNN North Dakota Acquisition

In January 2018, Water Solutions closed the acquisition of a 100% membership interest in Buckhorn Energy Services, LLC and Buckhorn SWD Solutions, LLC (collectively, "BNN North Dakota") for cash consideration of approximately $95.0 million, subject to working capital adjustments. BNN North Dakota owns a produced water gathering and disposal system in the Bakken basin with approximately 133,000 acres under dedication.

Potential Acquisition of Pawnee Terminal

On January 2, 2018, Terminals entered into an agreement to acquire a 51% membership interest in the Pawnee, Colorado crude oil terminal ("Pawnee Terminal") from Zenith Energy Terminals Holdings, LLC for cash consideration of approximately $31 million, subject to working capital adjustments. Terminals expects the transaction to close in the first quarter of 2018, subject to certain closing conditions.

Acquisition of Additional Interest in Pony Express

Effective February 1, 2018, we acquired the remaining 2% membership interest in Pony Express, along with administrative assets consisting primarily of information technology assets, from Tallgrass Development for cash consideration of approximately $60 million, bringing our aggregate membership interest in Pony Express to 100%.

Potential Joint Venture and Sale of TCG

On February 6, 2018, we entered into an agreement with an affiliate of Silver Creek Midstream, LLC ("Silver Creek") to form Iron Horse Pipeline, a new joint venture pipeline to transport crude oil from the Powder River Basin. In addition to forming the joint venture, we also agreed to sell to Silver Creek our 100% membership interest in TCG, which owns a 50-mile crude oil gathering system in the Powder River Basin. We expect to close the sale of TCG and the formation of the joint venture in February 2018.

Seneca Lateral

On January 31, 2018, Rockies Express experienced an operational disruption on its Seneca Lateral due to a pipe rupture and natural gas release in a rural area in Noble County, Ohio. There were no injuries reported and no evacuations, however, the release required Rockies Express to shut off the flow through the segment. Repairs are underway to return the segment to service as soon as possible and a root cause investigation is ongoing.

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, 2017, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective.

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 consolidated financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2017, the Partnership's management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control - Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Our assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of acquisitions made in 2017 of Terminals, the Douglas Gathering System and the 49% membership interest in Deeprock Development whose total assets and total revenue excluded from management's assessment collectively represent approximately 11% and 5%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2017. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal control over financial reporting during the first year of an acquisition while integrating the acquired company. Management is in the process of integrating these acquisitions and the Partnership's internal controls over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. Based on this assessment and those criteria, management determined that we maintained effective internal control over financial reporting as of December 31, 2017.

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, 2017, 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, 2017 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 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 the officers and directors of our general partner. TEGP owns a 31.43% 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. All the executive officers and certain of the directors of our general partner are also officers and/or directors of TEGP Management and Tallgrass Energy Holdings.

As of December 31, 2017, 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. The four independent directors are Jeffrey A. Ball, 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 its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act. As of December 31, 2017, the audit committee of the board of directors of our general partner had three members, each of whom meet the independence and experience 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 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 business time to our business and affairs as they deem reasonably required to manage and conduct our operations. Our general partner and its affiliates do not 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 13, 2018.

Name	Age	Position with our General Partner
David G. Dehaemers, Jr.	57	President, Chief Executive Officer and Director
William R. Moler	52	Executive Vice President, Chief Operating Officer and Director
Gary J. Brauchle	44	Executive Vice President and Chief Financial Officer
Christopher R. Jones	41	Vice President, General Counsel and Secretary
Gary D. Watkins	45	Vice President and Chief Accounting Officer
Frank J. Loverro	48	Director
Stanley de J. Osborne	47	Director
Jeffrey A. Ball	43	Director
John T. Raymond	47	Director
Terrance D. Towner	59	Director
Roy N. Cook	60	Director
Jeffrey R. Armstrong	48	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 has also served on the Board of the National Parkinson's Foundation Heartland Region and served as its President from 2015 to 2017. 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.

Christopher R. Jones has been Vice President, General Counsel and Secretary of our general partner, TEGP Management and Tallgrass Energy Holdings since May 2016. Previously, Mr. Jones served as Tallgrass's Assistant General Counsel, beginning in October 2012. Prior to joining Tallgrass, Mr. Jones was an attorney with the law firm that is now known as Stinson Leonard Street LLP from 2003 to 2012, becoming a partner in 2008. Mr. Jones holds an undergraduate degree and a Juris Doctorate in Law from the University of Kansas.

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, Physicians Endoscopy, LLC, Poseidon Containers Holdings LLC and Zenith Energy U.S., L.P. 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 $55 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, Ascent Resources, LLC, Sable PRES 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 $15.8 billion of regulatory assets under management (RAUM) as of September 30, 2017. EMG has allocated approximately $10.5 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 and as a member of the audit committee of our general partner since December 2017. 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 businesses 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 since April 2014 and was a member of the audit committee of our general partner from April 2014 to December 2017. In August 2014, Mr. Armstrong became the Chief Executive Officer of Zenith Energy, LP, a privately held midstream energy company. 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 Roy N. Cook. Each audit committee member has past experience in accounting or related financial management experience. The board has determined that all 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

Our general partner may, from time to time, have a conflicts committee to which the board of directors will appoint at least two independent directors and which may be asked to review specific matters that the board believes may involve conflicts of interest between our general partner and its affiliates, on one hand, and us and our unitholders, on the other. The conflicts committee will determine if the resolution of any conflict of interest referred to it by our general partner is in the best interests of our partnership. There is no requirement that our general partner seek the approval of the conflicts committee for the resolution of any conflict. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, may not hold an ownership interest in our general partner or its affiliates other than shares or awards under any long-term incentive plan, equity compensation plan or similar plan implemented by the general partner or us, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. The conflicts committee currently consists of two independent directors, Roy N. Cook and Terrance D. Towner, with Mr. Cook currently acting as the Chairman.

Any matters approved by the conflicts committee will be conclusively deemed to have been approved by all of our partners, and shall not constitute a breach by our general partner of any duties it may owe us or our unitholders. Any unitholder challenging any matter approved by the conflicts committee will have the burden of proving that the members of the conflicts committee did not subjectively believe that the matter was in the best interests of our partnership. Moreover, any acts taken or omitted to be taken in reliance upon the advice or opinions of experts such as legal counsel, accountants, appraisers, management consultants and investment bankers, where our general partner (or any members of the board of directors of our general partner including any member of the conflicts committee) reasonably believes the advice or opinion to be within such person's professional or expert competence, shall be conclusively presumed to have been done or omitted in good faith.

Corporate Governance Guidelines and Code of Business Conduct and Ethics

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

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 members of our general partner's board of directors, executive officers of our general partner, 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 2017 pursuant to Section 16(a) of the Exchange Act.

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 13, 2018, TEGP owns a 31.43% membership interest in and is managing member of Tallgrass Equity, which owns a 34.60% 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. We reimburse Tallgrass Energy Holdings and its affiliates, including Tallgrass Management, 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 our general partner and Tallgrass Energy Holdings 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 our 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 actual and anticipated contribution to 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 benchmark our salary amounts to comparable companies in our industry. 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. Our Named Executive Officers receive grants under both the TEP and TEGP LTIP (as defined below). TEP and TEGP share the same primary long-term performance measure of increasing quarterly distributions while maintaining safe operations and long-term stable cash flow and financial health. As a result of TEGP's controlling membership interest in Tallgrass Equity and indirect ownership of a 35% limited partnership interest in TEP, all of TEP's general partner interest and all of TEP's incentive distribution rights, failing to achieve that performance standard at TEP would be detrimental to TEGP, and vice versa. We therefore believe granting our Named Executive Officers equity participation units under the TEP LTIP and equity participation shares under the TEGP LTIP appropriately incentivizes our Named Executive Officers to seek stable distribution growth at both entities. We expect equity participation unit awards under the TEP LTIP will be the primary long-term equity incentive provided to our Named Executive Officers, and that grants of equity participation shares will be made pursuant to the TEGP LTIP on a more limited basis.

Long-Term Incentive Awards of TEP. 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 equity participation unit awards can generally be divided into four 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. Generally, one-third of the awards in this category vested on May 13, 2015 and the remaining two-thirds vested 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 our 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 TEP Distribution Achievement Date or May 13, 2019. The TEP Distribution Achievement Date occurred on May 13, 2016, 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. Mr. Jones and Mr. Watkins are the only Named Executive Officers that were granted equity participation units in this second category.

The third category of our equity participation unit awards were granted in November 2016 and will vest on November 1, 2019 as long as the employee satisfies the continuing service requirement set forth in the applicable award agreement. Mr. Jones and Mr. Watkins are the only Named Executive Officers that were granted equity participation units in this third category.

The fourth category of our equity participation unit awards were granted in August 2017 (the "2017 Grants") and will vest on the earliest date on or after April 1, 2021, on which the average compounded annual distribution growth rate for our regular quarterly distributions, based upon the regular quarterly distribution paid by us on, or immediately prior to, such date is at least 5% over an annualized distribution rate of $3.34 per common unit, as determined by the board of directors of our general partner. If such date has not occurred by August 2, 2024, such equity participation units will expire and terminate and no vesting will occur. Mr. Jones and Mr. Watkins are the only Named Executive Officers that were granted equity participation units in this fourth category.

Long-Term Incentive Awards of TEGP. Our Named Executive Officers also participate in the Long-Term Incentive Plan established by the general partner of TEGP effective May 1, 2015 ("TEGP LTIP"). Pursuant to the TEGP LTIP, 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"). 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. Jones and to Mr. Watkins, who are thus far the only Named Executive Officers to receive a grant under the TEGP LTIP. The terms of the awards to Mr. Jones and Mr. Watkins each stipulate that the 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 Achievement Date") or May 12, 2019. The TEGP Distribution Achievement Date was met upon payment of the $0.3550 distribution declared for the third quarter of 2017, thus these awards will vest on May 12, 2019 as long as the employee satisfies the continuing service requirement set forth in the applicable award agreement.

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. 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, 2017, our annual distribution per common unit has grown at a compound annual rate of 31%. 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 periodically during the year and then again in conjunction with the review and authorization of the annual budget and this annual report.

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. Executive management'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.

After the annual company-level performance analysis is completed by our CEO and other members of executive management, that same group, along with personnel from our human resources department, considers cash bonuses and salary adjustments for our employees, including our Named Executive Officers. There are no set formulas for determining salary adjustments or annual discretionary bonuses for our Named Executive Officers. Factors considered by executive management in determining the level of salary 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 and other members of executive management take 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 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 Named Executive Officer. Under existing LTIP Awards, achievement of performance targets does not shorten the minimum service period requirement.

Application in 2017

At the beginning of 2017, we established the following financial performance objectives for 2017:

- Adjusted EBITDA of $620 - $680 million for the year ended December 31, 2017;
- Distributable Cash Flow of $570 - $630 million for the year ended December 31, 2017;
- Distribution coverage of 1.30x - 1.50x for the year ended December 31, 2017; and
- Growth of approximately 20% in our annualized distribution rate for the calendar year 2017.

We achieved all these goals:

- Our Adjusted EBITDA for the year ended December 31, 2017 was approximately $678.0 million;
- Our Distributable Cash Flow for the year ended December 31, 2017 was approximately $611.3 million;
- Our distribution coverage for the year ended December 31, 2017 was 1.47x; and
- We grew our annualized distribution rate during calendar year 2017 by 18.4%.

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. We achieved several accomplishments with respect to these qualitative goals, including:

- The acquisitions from Tallgrass Development of a 24.99% membership interest in Rockies Express in March 2017 and 100% of the membership interests in Terminals and NatGas in January 2017;
- Third-party acquisitions of the Douglas Gathering System in June 2017, the additional 40% membership interests Deeprock Development in July 2017, and the PRB Crude System in August 2017;
- The contract extension with Continental Resources, Inc. through October 31, 2024 for transportation on the Pony Express System;

- The commencement of new expansion projects, including the Platteville Extension Project on the Pony Express System and the Cheyenne Connector Pipeline; and
- The amendment and restatement of our 1.75 billion revolving credit facility and senior note offerings of 2024 Notes and 2028 Notes in an aggregate of $1.1 billion.

For 2017, the elements of compensation were applied as described below.

Salary. In 2017, 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 performance relative to our 2017 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, Mr. Jones and Mr. Watkins received grants of 90,000 and 35,000 equity participation units, respectively, in 2017. No equity participation shares were granted to a Named Executive Officer under the TEGP LTIP in 2017. As noted below, we believe the substantial direct and indirect equity interests held by our management team, including our Named Executive Officers, in TEP, 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. Although we encourage our Named Executive Officers to acquire and retain ownership in TEP common units and TEGP Class A shares, we do not require our Named Executive Officers to maintain 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 in TEP or TEGP. Based on the closing price of TEP's common units and TEGP's Class A shares on February 9, 2018, the value of the combined equity ownership of our Named Executive Officers discussed below was significantly greater than their combined aggregate salaries and bonuses for 2017. We believe that the substantial direct and indirect equity interests held by our management team in TEGP, Tallgrass Energy Holdings and TEP 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.

Equity Ownership in TEP. Our Named Executive Officers collectively own substantial equity in TEP. As of February 9, 2018, our Named Executive Officers directly owned, in the aggregate, 721,588 of our common units (excluding any unvested LTIP Awards).

Equity Ownership in TEGP and Tallgrass Energy Holdings. 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 9, 2018, our Named Executive Officers beneficially owned, in the aggregate, 578,080 of TEGP's Class A shares (excluding any unvested LTIP Awards). As of February 9, 2018, Tallgrass KC owned 30,820,458 Class B Shares in TEGP and 30,820,458 Units in Tallgrass Equity, representing an approximate 16.68% ownership interest in TEGP and Tallgrass Equity, respectively. On such date, Tallgrass KC also owned approximately 27.61% of the outstanding voting equity interests in Tallgrass Energy Holdings.

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 other than the 2017 Grants include accelerated vesting triggered upon a change of control, as defined in the respective award agreements. The 2017 Grants include accelerated vesting if either (i) both (A) a qualifying transaction occurs, as defined in the award agreement, and (B) Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner and certain of our affiliates, or (ii) (A) Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner and certain of our affiliates, and (B) the Named Executive Officer is thereafter terminated without cause. The provision of equity acceleration for defined events 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."* Except for the accelerated vesting of the 2017 Grants if Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner and certain of our affiliates and the Named Executive Officer is thereafter terminated without cause, 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 and financing 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*. 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 2017 (the "Named Executive Officers") for services rendered to all Tallgrass-related entities, including TEP, TEGP, Tallgrass Management and Tallgrass Development, for the fiscal years ending December 31, 2017, 2016, and 2015.

	Year	Salary (1)	Bonus (2)	Equity Awards (3)	All Other Compensation (4)	Total
David G. Dehaemers, Jr.	2017	$ 300,000	$1,000,739	$ —	$ 28,152	$ 1,328,891
President, Chief Executive	2016	$ 300,000	$ 651,467	$ —	$ 27,544	$ 979,011
Officer and Director	2015	$ 300,000	$ 601,000	$ —	$ 27,796	$ 928,796
William R. Moler	2017	$ 300,000	$ 400,943	$ —	$ 28,152	$ 729,095
Executive Vice President, Chief	2016	$ 300,000	$ 576,468	$ —	$ 24,544	$ 901,012
Operating Officer and Director	2015	$ 300,000	$ 551,000	$ —	$ 27,796	$ 878,796
Gary J. Brauchle	2017	$ 299,712	$ 750,942	$ —	$ 27,955	$ 1,078,609
Executive Vice President and	2016	$ 294,904	$ 576,144	$ —	$ 27,537	$ 898,585
Chief Financial Officer	2015	$ 275,000	$ 551,000	$ —	$ 27,665	$ 853,665
Christopher R. Jones (5)	2017	$ 271,569	$ 750,942	$ 3,545,100	$ 27,686	$ 4,595,297
Vice President, General Counsel	2016	$ 240,068	$ 426,467	$ 69,836	$ 24,486	$ 760,857
and Secretary						
Gary D. Watkins	2017	$ 224,922	$ 248,435	$ 1,378,650	$ 23,356	$ 1,875,363
Vice President and	2016	$ 222,975	$ 201,470	$ 69,836	$ 23,081	$ 517,362
Chief Accounting Officer	2015	$ 212,322	$ 201,000	$ 1,226,264	$ 22,152	$ 1,661,738

(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.

(2) Represents discretionary bonuses paid in 2018, 2017 and 2016 based on performance in 2017, 2016 and 2015, respectively, as well as a bonus of $500 after tax that was paid to all employees in 2017, a bonus of $1,000 after tax that was paid to all employees in 2016, and a $1,000 pre-tax bonus that was paid to all employees in 2015.

(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. Mr. Jones and Mr. Watkins were the only Named Executive Officers to receive grants under the TEP LTIP during 2016 and 2017 and Mr. Watkins was the only Named Executive Officer to receive grants under the TEGP LTIP 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, or EPSs, 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 EPUs and EPSs 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*. 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 $27,000 for Mr. Dehaemers, $27,000 for Mr. Moler, $26,804 for Mr. Brauchle, $26,640 for Mr. Jones, and $22,492 for Mr. Watkins for the year ended December 31, 2017, $26,500 for Mr. Dehaemers, $26,500 for Mr. Moler, $26,500 for Mr. Brauchle, $23,629 for Mr. Jones, and $22,297 for Mr. Watkins for the year ended December 31, 2016, and $26,500 for Mr. Dehaemers, $26,500 for Mr. Moler, $26,477 for Mr. Brauchle, and $21,232 for Mr. Watkins for the year ended December 31, 2015) and the dollar value of premiums paid for group life, accidental death and dismemberment insurance.

(5) Mr. Jones was appointed Vice President, General Counsel and Secretary of TEP and TEGP effective July 1, 2016.

As required by Section 953(b) of the Dodd-Frank Act and Item 402(u) of Regulation S-K, we are providing information regarding the internal pay ratio between the annual total compensation of our Chief Executive Officer and the median of the annual total compensation of all employees. Because we do not have any of our own employees, we are providing this ratio based on the total compensation of all employees of Tallgrass Management as of December 31, 2017. Employees of Tallgrass Management provide certain services to us and our consolidated subsidiaries under the TEP Omnibus Agreement. To determine the median of the annual total compensation of all such employees, excluding our Chief Executive Officer, we identified the “median employee” by comparing the amount of salary, wages and tips of such employees, whether full-time, part-time, seasonal or temporary, as reflected in the payroll records of Tallgrass Management for the period from January 1, 2017 through December 31, 2017. We determined that our Chief Executive Officer had annual total compensation of $1,328,891, which is reflected in the Summary Compensation Table above, and the median of the annual total compensation of all employees, excluding our Chief Executive Officer, was $107,028. Therefore, our Chief Executive Officer’s annual total compensation is 12.4 times that of the median of the annual total compensation of all employees of Tallgrass Management.

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 2017, including, but not limited to awards made under the TEP LTIP and TEGP LTIP.

	Grant Type	Grant Date	Number of Shares or Units	Grant Date Fair Value of Awards[(1)]
Christopher R. Jones				
Vice President, General Counsel	TEP Equity Participation Units	8/2/17	90,000 [(2)]	$ 3,545,100
and Secretary	TEGP Equity Participation Shares	—	— [(3)]	$ —
Gary D. Watkins				
Vice President and	TEP Equity Participation Units	8/2/17	35,000 [(2)]	$ 1,378,650
Chief Accounting Officer	TEGP Equity Participation Shares	—	— [(3)]	$ —

(1) The amounts in this column include EPUs granted pursuant to the TEP 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, if applicable, 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*. These amounts do not correspond to the actual value that will be recognized by the executive.

(2) Vesting of the equity participation units will occur on the earliest date on or after April 1, 2021, on which the average compounded annual distribution growth rate for our regular quarterly distributions, based upon the regular quarterly distribution paid by us on, or immediately prior to, such date is at least 5% over an annualized distribution rate of $3.34 per common unit, as determined by the board of directors of our general partner. If such date has not occurred by August 2, 2024, such equity participation units will expire and terminate and no vesting will occur.

(3) There were no equity participation shares granted under the TEGP LTIP during the year ended December 31, 2017.

Outstanding Equity Awards at Fiscal Year-End

The following table reflects the outstanding equity awards of our Named Executive Officers as of December 31, 2017 under the TEP LTIP.

	Equity Participation Unit Awards [(1)]			
	Number of EPU Awards That Have Not Vested	Market Value of EPU Awards That Have Not Vested [(2)]	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	—	$ —	—	$ —
Gary J. Brauchle.............................	—	$ —	—	$ —
Christopher R. Jones	97,800 [(3)]	$ 4,484,130	—	$ —
Gary D. Watkins.............................	43,400 [(4)]	$ 1,989,890	—	$ —

(1) The award agreements pursuant to which the EPUs set forth above were granted provide for the settlement of the EPUs in common units.

(2) Reflects the closing price of $45.85 per TEP common unit at December 29, 2017.

(3) Mr. Jones holds 2,900 EPUs that will vest on May 13, 2018, 2,900 EPUs that will vest on May 13, 2019, and 2,000 EPUs that will vest on November 1, 2019 as long as he meets the required continuing service obligations. The remaining 90,000 EPUs will vest on the earliest date on or after April 1, 2021, on which the average compounded annual distribution growth rate for our regular quarterly distributions, based upon the regular quarterly distribution

paid by us on, or immediately prior to, such date is at least 5% over an annualized distribution rate of $3.34 per common unit, as determined by the board of directors of our general partner. If such date has not occurred by August 2, 2024, these 90,000 EPUs will expire and terminate and no vesting will occur.

(4) Mr. Watkins holds 3,200 EPUs that will vest on May 13, 2018, 3,200 EPUs that will vest on May 13, 2019, and 2,000 EPUs that will vest on November 1, 2019 as long as he meets the required continuing service obligations. The remaining 35,000 EPUs that will vest on the earliest date on or after April 1, 2021, on which the average compounded annual distribution growth rate for our regular quarterly distributions, based upon the regular quarterly distribution paid by us on, or immediately prior to, such date is at least 5% over an annualized distribution rate of $3.34 per common unit, as determined by the board of directors of our general partner. If such date has not occurred by August 2, 2024, these 35,000 EPUs will expire and terminate and no vesting will occur.

The following table reflects all outstanding equity awards of our named executive officers as of December 31, 2017 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**	**Market or Payout Value of Unearned Equity Participation Shares That Have Not Vested [2]**
David G. Dehaemers, Jr.	—	$ —	—	$ —
William R. Moler	—	$ —	—	$ —
Gary J. Brauchle	—	$ —	—	$ —
Christopher R. Jones	35,000 [3]	$ 900,900	—	$ —
Gary D. Watkins	35,000 [3]	$ 900,900	—	$ —

(1) 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) Reflects the closing price of $25.74 per TEGP Class A share at December 29, 2017.

(3) Mr. Jones and Mr. Watkins each hold 35,000 equity participation shares that will vest on May 12, 2019 as long as they meet the required continuing service obligations.

Units Vested

The following table sets forth certain information regarding the vesting of TEP LTIP Awards during the fiscal year ended December 31, 2017. No TEGP Equity Participation Share Awards vested during 2017.

	Number of EPUs 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*	33,333	$ 1,675,983
Gary J. Brauchle *Executive Vice President and Chief Financial Officer*	33,333	$ 1,675,983
Christopher R. Jones *Vice President, General Counsel and Secretary*	16,000	$ 804,480
Gary D. Watkins *Vice President and Chief Accounting Officer*	16,666	$ 837,966

(1) Represents the gross number of EPUs that vested during the year ended December 31, 2017. 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 ($50.28) of our common units on the date they vested (May 13, 2017) 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 November 2, 2016, Mr. Dehaemers entered into a second amended and restated employment agreement with Tallgrass Management, our general partner, Tallgrass Energy Holdings, Tallgrass Equity and TEGP Management, pursuant to which he agreed to serve as the President and Chief Executive Officer of our general partner. 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 TEP 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 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 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) a material diminution of Mr. Dehaemers' duties and responsibilities to Tallgrass Management or certain of its affiliates to a level inconsistent with those of a chief executive officer; (ii) 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); (iii) a willful or intentional breach of his employment agreement by Tallgrass Management; or (iv) 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, except for the acceleration of the 2017 Grants under the circumstances further described below, 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 other than the 2017 Grants typically provide for acceleration of vesting in connection with a change in control. The TEP LTIP Awards held by our Named Executive Officers other than the 2017 Grants 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 2017 Grants include accelerated vesting if either (i) both (A) a qualifying transaction occurs, and (B) Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner and certain of our affiliates, or (ii) (A) Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner and certain of our affiliates, and (B) the Named Executive Officer is thereafter terminated without cause. Under the award agreements for the 2017 Grants, a qualifying transaction means any transaction in which:

- a person other than certain designated persons directly or indirectly acquires direct or indirect ownership or control of 50% or more of the voting interests in our general partner, the ownership of fifty percent 50% or more of the general partner interests in TEP, or the ownership of such other rights or interests that grant to the owner or holder thereof the ability to direct the management or policies of TEP, whether through the ownership of voting rights, by contract, or otherwise;
- our limited partners 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 and its affiliates.

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 triggering change in control event occurred on December 31, 2017.

		Upon a Change in Control [1]
David G. Dehaemers, Jr.		
TEP LTIP	$	—
TEGP LTIP	$	—
William R. Moler		
TEP LTIP	$	—
TEGP LTIP	$	—
Gary J. Brauchle		
TEP LTIP	$	—
TEGP LTIP	$	—
Christopher R. Jones		
TEP LTIP	$	4,484,130
TEGP LTIP	$	900,900
Gary D. Watkins		
TEP LTIP	$	1,989,890
TEGP LTIP	$	900,900

(1) The stated value upon a change in control is computed by assuming that a triggering change of control event occurred on December 29, 2017 and multiplying the closing market price (TEP: $45.85 and TEGP: $25.74) 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. In addition, under the terms of the award agreements for the 2017 Grants, Mr. Jones and Mr. Watkins have agreed not to compete with our general partner and its affiliates for the period commencing on the grant date and ending upon the earlier of (i) if a vesting date occurs, 18-months following termination of such person's employment, (ii) the date such EPUs are forfeited without vesting, and (iii) the date such EPUs expire. Each of the Named Executive Officers has signed a confidentiality agreement in connection with their employment by Tallgrass Management.

Compensation of Directors

Officers or employees of Tallgrass Energy Holdings or its affiliates, including certain directors affiliated with EMG or Kelso, who also serve as directors of our general partner do not receive additional compensation for such service. In 2017, those directors of our general partner who were not excluded from receiving compensation were paid cash compensation as follows:

- Quarterly cash payments of $10,000, resulting in an effective annual cash payment of $40,000.
- For serving as the conflicts committee chair, a quarterly committee chair cash payment 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 TEP LTIP.

The following table sets forth certain information with respect to our non-employee directors receiving cash compensation and EPU awards during the year ended December 31, 2017.

Name and Principal Position	Fees Earned	EPU Awards	Non-Equity Incentive Plan Compensation	Total
Terrance D. Towner	$ 40,000	$ 63,930	$ —	$ 103,930
Roy N. Cook	$ 60,000	$ 63,930	$ —	$ 123,930
Jeffrey R. Armstrong	$ 40,000	$ 63,930	$ —	$ 103,930

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 is not present for any discussions regarding his performance or 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, 2017 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 9, 2018 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 73,199,753 common units outstanding as of February 9, 2018.

Name of Beneficial Owner (1)	Common Units Beneficially Owned (2)	Percentage of Common Units Beneficially Owned
Tallgrass Energy Holdings (3)	25,619,218	35.00%
Tortoise Capital Advisors, L.L.C. (4)	7,206,390	9.84%
Funds advised by ALPS Advisors, Inc. (5)	3,910,660	5.34%
Salient Capital Advisors, LLC (6)	3,700,374	5.06%
David G. Dehaemers, Jr. (7)	573,206	*
William R. Moler (8)	47,761	*
Gary J. Brauchle (9)	62,113	*
Christopher R. Jones	20,615	*
Gary D. Watkins	17,893	*
Frank J. Loverro	—	—
Stanley de J. Osborne	—	—
Jeffrey A. Ball	20,000	*
John T. Raymond	100,000	*
Roy N. Cook	52,000	*
Terrance D. Towner	25,000	*
Jeffrey R. Armstrong	3,000	*
All directors and executive officers as a group (12 persons)	921,588	1.26%

* 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 Tallgrass Equity. 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 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; however, each disclaims beneficial ownership.

(4) As reported on Schedule 13G filed with the SEC on July 7, 2017. Tortoise Capital Advisors, L.L.C. ("TCA") acts as an investment advisor to certain investment companies registered under the Investment Company Act of 1940. TCA, by virtue of investment advisory agreements with these investment companies, has all investment and voting power over securities owned of record by these investment companies. However, despite their delegation of investment and voting power to TCA, these investment companies may be deemed to be the beneficial owner under Rule 13d-3 of the Act, of the

securities they own of record because they have the right to acquire investment and voting power through termination of their investment advisory agreement with TCA. Thus, TCA has reported on the Schedule 13G that it shares voting power and dispositive power over the securities owned of record by these investment companies. TCA also acts as an investment adviser to certain managed accounts. Under contractual agreements with these managed account clients, TCA, with respect to the securities held in these client accounts, has investment and voting power with respect to certain of these client accounts, and has investment power but no voting power with respect to certain other of these client accounts. TCA has reported on the Schedule 13G that it shares voting and/or investment power over the securities held by these client managed accounts despite a delegation of voting and/or investment power to TCA because the clients have the right to acquire investment and voting power through termination of their agreements with TCA. TCA may be deemed the beneficial owner of the securities covered by the Schedule 13G under Rule 13d-3 of the Act that are held by its clients. The business address for this person is 11550 Ash Street, Suite 300, Leawood, Kansas 66211.

(5) As reported on Schedule 13G filed with the SEC on February 6, 2018. ALPS Advisors, Inc. ("AAI"), an investment adviser registered under Section 203 of the Investment Advisors Act of 1940, furnishes investment advice to investment companies registered under the Investment Company Act of 1940 (collectively referred to as the "AAI Funds"). In its role as investment advisor, AAI has voting and/or investment power over the securities of TEP that are owned by the AAI Funds, and may be deemed to be the beneficial owner of the shares of TEP held by the AAI Funds. However, all securities reported in this schedule are owned by the AAI Funds. AAI disclaims beneficial ownership of such securities. In addition, the filing of the Schedule 13G shall not be construed as an admission that the reporting person or any of its affiliates is the beneficial owner of any securities covered by the Schedule 13G for any other purposes than Section 13(d) of the Securities Exchange Act of 1934. Alerian MLP ETF, which beneficially owns 3,887,310 common units, is an investment company registered under the Investment Company Act of 1940 and is one of the AAI Funds to which AAI provides investment advice. The business address for AAI and Alerian MLP ETF is 1290 Broadway, Suite 110, Denver, Colorado 80203.

(6) As reported on Schedule 13G filed with the SEC on January 18, 2018. Consists of common units of record by Salient Capital Advisors, LLC. The business address for this person is 4265 San Felipe, 8th Floor, Houston, TX 77027.

(7) 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.

(8) 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.

(9) 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, 2017:

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)	989,393	$ 38.58	7,957,987
Equity compensation plans not approved by security holders (2)	—	$ —	—
Total	989,393	$ 38.58	7,957,987

(1) Amounts shown represent equity participation unit awards outstanding under the TEP LTIP as of December 31, 2017. 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*.

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

As of February 13, 2018, Tallgrass Equity owned 25,619,218 common units representing approximately 35% of our outstanding limited partner common units. In addition, our general partner owns 834,391 general partner units representing an approximate 1.13% 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 Equity as the holder of an aggregate of 25,619,218 common units) and to our general partner as follows: (1) an approximate 1.13% general partner interest with respect to TEP GP's 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 approximately $30.4 million on their common units based on their ownership as of February 9, 2018. We have distributed available cash in excess of the MQD since the quarterly period ending September 30, 2013.

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.

TEP Omnibus Agreement

Upon the closing of the IPO, we entered into the TEP Omnibus Agreement with Tallgrass Development Holdings (as successor to Tallgrass Development), 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 owned by Tallgrass Development Holdings, which currently only includes the 25.01% membership interest in Rockies Express, if Tallgrass Development Holdings decides to sell such assets to a non-affiliate.

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, 2017, 2016, and 2015, we reimbursed Tallgrass Energy Holdings $41.9 million, $40.9 million, and $37.9 million, respectively, pursuant to the TEP Omnibus Agreement.

Indemnification

Under the terms of the TEP Omnibus Agreement, Tallgrass Development Holdings 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 Holdings 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 Holdings 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 Holdings 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 Holdings has granted us a right of first offer, for so long as Tallgrass Development Holdings or its affiliates, individually or as part of a group, control our general partner, on (i) the 25.01% membership interest in Rockies Express owned by Tallgrass Development Holdings and (ii) any assets that are hereafter developed, constructed or acquired by Tallgrass Development Holdings 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 Holdings or any of its affiliates decide to attempt to sell (other than to an affiliate of Tallgrass Development Holdings, excluding TEP and its subsidiaries) a ROFO Asset, Tallgrass Development Holdings 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 Holdings or its affiliate and us. If we and Tallgrass Development Holdings 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 Holdings 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 Holdings 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 Holdings, and we will have a 90-day transition period to cease our use of the name "Tallgrass" and related marks.

Acquisitions from Tallgrass Development

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, LLC ("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 provided 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 were 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 accrued interest at Tallgrass Development's incremental borrowing rate. As of September 1, 2014, balances lent to Tallgrass Development under the cash management agreement were classified as related party receivables on our consolidated balance sheet and were cash settled.

Effective March 1, 2015, we 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 us. 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 provided us 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, we 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 us, pursuant to that certain Contribution and Transfer Agreement by and between Tallgrass Development, Tallgrass Operations and us. In July 2016, October 2016 and on February 1, 2017, we exercised the call option granted by Tallgrass Development covering 3,563,146, 1,251,760 and 1,703,094 common units, respectively. These common units were deemed canceled upon the exercise of the call option and as of such exercise date were no longer issued and outstanding. As of February 13, 2018, no common units remained subject to the call option.

On May 6, 2016, Tallgrass Development assigned us its right to purchase a 25% membership interest in Rockies Express from a unit of Sempra U.S. Gas and Power ("Sempra") pursuant to the purchase agreement originally entered into between Tallgrass Development's wholly-owned subsidiary and Sempra in March 2016. Subsequently on May 6, 2016, we closed the purchase of a 25% membership interest in Rockies Express from Sempra pursuant to the purchase agreement for cash consideration of approximately $436.0 million, after making the adjustments to the purchase price required by the purchase agreement.

Effective January 1, 2017, we acquired 100% of the issued and outstanding membership interests in Terminals and 100% of the issued and outstanding membership interests in NatGas from TD for total cash consideration of $140 million, pursuant to that certain Purchase and Sale Agreement by and between Tallgrass Development, Tallgrass Operations and us.

Following an offer received from Tallgrass Development with respect to common units owned by Tallgrass Development not subject to the call option, we repurchased 736,262 common units from Tallgrass Development at an aggregate price of approximately $35.3 million, or $47.99 per common unit, on February 1, 2017, which was approved by the conflicts committee of the board of directors of our general partner.

Effective March 31, 2017, we acquired an additional 24.99% membership interests in Rockies Express from Tallgrass Development for cash consideration of $400 million, pursuant to that certain Purchase and Sale Agreement by and between us and Rockies Express Holdings, LLC, a wholly-owned subsidiary of Tallgrass Development, and for certain limited purposes, Tallgrass Development.

Effective February 1, 2018, we acquired the remaining 2% membership interest in Pony Express, along with administrative assets consisting primarily of information technology assets, from Tallgrass Development for cash consideration of approximately $60 million, bringing our aggregate membership interest in Pony Express to 100%.

Competition

Under our partnership agreement, Tallgrass Energy Holdings and its affiliates are expressly permitted to compete with us. Tallgrass Energy Holdings and any of its affiliates, including EMG and Kelso may acquire, construct or dispose of additional transportation, storage, terminalling 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 was an indirect wholly-owned subsidiary of Tallgrass Development prior to our acquisition in January 2017. Pursuant to such agreement, Pony Express leases approximately 1.3 million barrels of crude oil storage and Sterling Terminal provides associated crude oil terminalling 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. Pony Express made lease payments to Sterling Terminal of $11.7 million, $11.5 million and $7.6 million during the years ended December 31, 2017, 2016 and 2015, respectively, pursuant to the agreement.

In May 2016, Pony Express entered into an electric service master meter agreement with Terminals, which was an indirect wholly-owned subsidiary of Tallgrass Development prior to our acquisition in January 2017. Pursuant to such agreement, Terminals receives electric power from Pony Express at the Sterling Terminal. Terminals pays Pony Express for its usage based on the charges incurred by Pony Express from its third-party electric service provider. Terminals made payments to Pony Express under the agreement of $0.4 million during the years ended December 31, 2017 and 2016.

Other Transactions

On January 2, 2018, Terminals entered into an agreement to acquire a 51% membership interest in the Pawnee Terminal from Zenith Energy Terminals Holdings, LLC for cash consideration of approximately $31 million, subject to working capital adjustments. Terminals expects the transaction to close in the first quarter of 2018, subject to certain closing conditions. Jeff Armstrong, who is on the board of directors of our general partner, is the Chief Executive Officer of Zenith Energy Terminals Holdings, LLC. Kelso owns an indirect equity interest in Zenith Energy Terminals Holdings, LLC.

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,			
	2017		2016	
	(in thousands)			
Audit fees [1]	$	1,592	$	1,634
Audit related fees [2]		—		—
Tax fees [3]		520		445
Total	$	2,112	$	2,079

(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, 2017.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(1) Financial Statements

Consolidated Financial Statements included in this Item 15:

Financial Statements of Rockies Express Pipeline LLC

FINANCIAL STATEMENTS

ROCKIES EXPRESS PIPELINE LLC

For the years ended December 31, 2017, 2016 and 2015

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Rockies Express Pipeline LLC

We have audited the accompanying financial statements of Rockies Express Pipeline LLC, which comprise the balance sheets as of December 31, 2017 and 2016, and the related statements of income, members' equity, and cash flows for each of the three years in the period ended December 31, 2017.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Rockies Express Pipeline LLC as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As described in Note 6 to the financial statements, the Company has significant transactions with related parties. Our opinion is not modified with respect to this matter.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 13, 2018

ROCKIES EXPRESS PIPELINE LLC
BALANCE SHEETS

	December 31,	
	2017	2016
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 25.7	$ 118.4
Accounts receivable, net	75.8	59.4
Regulatory assets	10.9	12.3
Gas imbalances	6.3	2.6
Other current assets	3.7	3.0
Total Current Assets	122.4	195.7
Property, plant and equipment, net	5,939.2	6,063.7
Deferred charges and other assets	11.8	15.6
Total Noncurrent Assets	5,951.0	6,079.3
Total Assets	$ 6,073.4	$ 6,275.0
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts payable	$ 20.3	$ 38.1
Accrued interest	56.3	56.3
Accrued taxes	60.0	67.7
MFN revenue sharing liability	9.3	9.4
Current portion of long-term debt	550.0	—
Construction advances	6.8	11.7
Accrued other current liabilities	11.3	4.9
Total Current Liabilities	714.0	188.1
Long-term Liabilities and Deferred Credits:		
Long-term debt	2,014.8	2,561.7
Other long-term liabilities and deferred credits	34.5	95.2
Total Long-term Liabilities and Deferred Credits	2,049.3	2,656.9
Commitments and Contingencies		
Members' Equity:		
Members' equity	3,310.1	3,430.0
Total Liabilities and Members' Equity	$ 6,073.4	$ 6,275.0

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

ROCKIES EXPRESS PIPELINE LLC
STATEMENTS OF INCOME

	Years Ended December 31,		
	2017	2016	2015
		(in millions)	
Revenues:			
Transportation services	$ 839.6	$ 715.1	$ 779.0
Natural gas sales	9.6	—	2.1
Total Revenues	849.2	715.1	781.1
Operating Costs and Expenses:			
Cost of transportation services	29.8	26.5	30.2
Cost of natural gas sales	7.3	—	2.3
Operations and maintenance	25.3	24.8	21.2
Depreciation and amortization	218.4	204.3	199.4
General and administrative	30.5	39.9	26.7
Taxes, other than income taxes	65.3	71.9	73.9
Total Operating Costs and Expenses	376.6	367.4	353.7
Operating Income	472.6	347.7	427.4
Other (Expense) Income:			
Interest expense, net	(168.0)	(158.6)	(170.1)
Gain on litigation settlement	150.0	61.7	—
Other income, net	3.4	27.7	6.6
Total Other Expense, net	(14.6)	(69.2)	(163.5)
Net Income to Members	$ 458.0	$ 278.5	$ 263.9

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

ROCKIES EXPRESS PIPELINE LLC
STATEMENTS OF MEMBERS' EQUITY

		Total		Rockies Express Holdings, LLC		TEP REX Holdings, LLC		Sempra REX Holdings, LLC		P66 REX LLC
						(in millions)				
Members' Equity:										
Balance at January 1, 2015	$	2,820.2	$	1,410.0	$	—	$	705.1	$	705.1
Net Income to Members		263.9		131.9		—		66.0		66.0
Contributions from Members		733.1		366.5		—		183.3		183.3
Distributions to Members		(499.0)		(249.4)		—		(124.8)		(124.8)
Balance at December 31, 2015	$	3,318.2	$	1,659.0	$	—	$	829.6	$	829.6
Net Income to Members		278.5		139.3		42.6		27.0		69.6
Contributions from Members		304.9		152.5		50.0		26.2		76.2
Distributions to Members		(471.6)		(235.8)		(75.9)		(42.0)		(117.9)
Transfer of equity interest		—		—		840.8		(840.8)		—
Balance at December 31, 2016	$	3,430.0	$	1,715.0	$	857.5	$	—	$	857.5
Net Income to Members		458.0		131.1		212.4		—		114.5
Contributions from Members		92.0		29.7		39.3		—		23.0
Distributions to Members		(669.9)		(197.6)		(304.8)		—		(167.5)
Transfer of equity interest (see Note 1)		—		(850.3)		850.3		—		—
Balance at December 31, 2017	$	3,310.1	$	827.9	$	1,654.7	$	—	$	827.5

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

ROCKIES EXPRESS PIPELINE LLC
STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2017	2016	2015
		(in millions)	
Cash Flows from Operating Activities:			
Net income to Members	$ 458.0	$ 278.5	$ 263.9
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	223.7	209.6	204.8
Changes in components of working capital:			
Accounts receivable	(25.4)	28.2	(23.8)
Current regulatory assets and liabilities, net	3.4	(12.5)	(10.2)
Accounts payable	(7.0)	12.2	3.7
Accrued taxes	(7.6)	(0.6)	3.7
Other current assets and liabilities	—	(0.7)	(0.9)
Return of customer deposits	(55.7)	—	—
Receipt of customer deposits	5.8	52.9	32.2
Other operating, net	1.1	(22.5)	(3.0)
Net Cash Provided by Operating Activities	596.3	545.1	470.4
Cash Flows from Investing Activities:			
Capital expenditures	(108.9)	(305.7)	(281.9)
Other investing, net	(2.2)	(2.3)	(1.9)
Net Cash Used in Investing Activities	(111.1)	(308.0)	(283.8)
Cash Flows from Financing Activities:			
Distributions to Members	(669.9)	(471.6)	(499.0)
Contributions from Members	92.0	304.9	733.1
Repayment of debt	—	—	(450.0)
Payments for deferred financing costs	—	—	(0.7)
Net Cash Used in Financing Activities	(577.9)	(166.7)	(216.6)
Net Change in Cash and Cash Equivalents	(92.7)	70.4	(30.0)
Cash and Cash Equivalents, beginning of period	118.4	48.0	78.0
Cash and Cash Equivalents, end of period	$ 25.7	$ 118.4	$ 48.0
Supplemental Disclosures:			
Cash payments for interest, net	$ (164.9)	$ (155.6)	$ (170.7)
Schedule of Noncash Investing and Financing Activities:			
Increase in accrual for payment of property, plant and equipment	$ —	$ —	$ 8.4

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

ROCKIES EXPRESS PIPELINE LLC
NOTES TO FINANCIAL STATEMENTS

1. Description of Business

Rockies Express Pipeline LLC ("Rockies Express") is a Federal Energy Regulatory Commission ("FERC") regulated natural gas transportation system with approximately 1,712 miles of natural gas pipeline, including laterals, extending from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio and consisting of three zones:

- Zone 1 - a 328-mile pipeline from the Meeker Hub in Northwest Colorado, across Southern Wyoming to the Cheyenne Hub in Weld County, Colorado capable of transporting 2.0 Bcf/d of natural gas from west to east;
- Zone 2 - a 714-mile pipeline from the Cheyenne Hub to an interconnect in Audrain County, Missouri capable of transporting 1.8 Bcf/d of natural gas from west to east; and
- Zone 3 - a 643-mile pipeline from Audrain County, Missouri to Clarington, Ohio, which is bi-directional and capable of transporting 1.8 Bcf/d of natural gas from west to east and 2.6 Bcf/d of natural gas from east to west.

The member interests and voting rights in Rockies Express as of December 31, 2017 are as follows:

- 49.99% - TEP REX Holdings, LLC ("TEP REX"), an indirect wholly owned subsidiary of Tallgrass Energy Partners, LP ("TEP");
- 25.01% - Rockies Express Holdings, LLC ("REX Holdings"), an indirect wholly owned subsidiary of Tallgrass Development, LP ("TD"); and
- 25% - P66REX LLC, a wholly owned subsidiary of Phillips 66.

On March 31, 2017, TEP, TD, and REX Holdings, entered into a definitive Purchase and Sale Agreement, pursuant to which TEP acquired an additional 24.99% membership interest in Rockies Express from TD in exchange for cash consideration of $400 million. This transaction increased TEP’s aggregate membership interest in Rockies Express to 49.99%.

On February 7, 2018, Tallgrass Development Holdings, LLC ("Tallgrass Development Holdings") acquired REX Holdings and its 25.01% membership interest in Rockies Express as a result of the merger of TD into Tallgrass Development Holdings. Tallgrass Development Holdings is a wholly-owned subsidiary of Tallgrass Equity, LLC, which is the sole member of TEP's general partner.

2. Summary of Significant Accounting Policies

Basis of Presentation

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual results could differ from these estimates. Certain prior year amounts have been reclassified to conform to the current presentation.

Use of Estimates

Certain amounts included in or affecting these 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

Rockies Express considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are carried at their estimated collectible amounts. Rockies Express makes periodic reviews and evaluations of the appropriateness of the allowance for doubtful accounts based on a statistical analysis of historical defaults, and adjustments are recorded as necessary for changes in 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 $2.0 million at December 31, 2017 and 2016.

Fuel Recovery Mechanism

Rockies Express obtains natural gas quantities from its shippers as reimbursement for fuel consumed at compressor stations and other locations on its system as well as for natural gas quantities lost and otherwise unaccounted for, in accordance with its tariff and applicable contract terms. Rockies Express tracks the volume and value of associated over- or under-collections of fuel and lost and unaccounted for quantities through a tracking mechanism referred to as "fuel tracker." Those amounts are recorded as an addition or reduction to a regulatory asset or liability balance representing the amounts to be recovered from or refunded to customers through the fuel tracker mechanisms. Fuel tracker volumes are valued using a weighted-average monthly index price.

Accounting for Regulatory Activities

Rockies Express' regulated activities are accounted for in accordance with the "Regulated Operations" Topic of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("Codification"). This Topic prescribes the circumstances in which the application of GAAP is affected by the economic effects of regulation. Regulatory assets and liabilities represent probable future revenues or expenses to Rockies Express associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. Rockies Express recorded regulatory assets of approximately $10.9 million and $12.3 million at December 31, 2017 and 2016, respectively, and regulatory liabilities of approximately $2.0 million and $10,000 at December 31, 2017 and 2016, respectively. Regulatory assets and liabilities at December 31, 2017 and 2016 were primarily attributable to the fuel tracker discussed in *"Fuel Recovery Mechanism"* above. For additional details see Note 9 – *Regulatory Matters*.

Gas Imbalances

Gas imbalances receivable and payable reflect gas volumes owed between Rockies Express and its customers. Gas imbalances represent the difference between customer nominated versus actual gas receipts from and gas deliveries to interconnecting pipelines under various operational balancing agreements. Gas imbalances are settled in cash or made up in-kind subject to the terms of the various agreements and are valued at the average monthly index price.

Property, Plant and Equipment

Property, plant and equipment is stated at historical cost, which for constructed assets includes indirect costs such as payroll taxes, other employee benefits, allowance for funds used during construction 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. Rockies Express also capitalizes certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs.

Routine maintenance, repairs and renewal costs are expensed as incurred. The cost of normal retirements of 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 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.

Rockies Express maintains natural gas in its pipeline, known as "line pack," which serves to maintain the necessary pressure to allow efficient transmission of natural gas. Line pack is capitalized within "Property, plant and equipment, net" on the balance sheets and depreciated over the estimated useful life of the pipeline.

Impairment of Long-Lived Assets

Rockies Express reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss results when the estimated undiscounted future net cash flows expected to result from the asset's use and its eventual disposition are less than its carrying amount. Rockies Express assesses its long-lived assets for impairment in accordance with the relevant Codification guidance. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate its carrying amount may exceed its fair value.

Examples of long-lived asset impairment indicators include:

- a significant decrease in the market value of a long-lived asset or group;

- a significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition;
- a significant adverse change in legal factors or in the business climate could affect the value of a 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, Rockies Express first assesses 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 asset is assessed using a discounted cash flow analysis to determine the amount of impairment, if any, to be recognized.

Depreciation and Amortization

Depreciation is computed based on the straight-line method over the estimated useful lives of property, plant and equipment. The annual composite rate of depreciation for the years ended December 31, 2017, 2016, and 2015 was 2.86%.

Allowance for Funds Used During Construction

Included in the cost of "Property, plant and equipment, net" on the accompanying balance sheets is an allowance for funds used during construction ("AFUDC"). AFUDC represents the estimated cost of debt, from borrowed funds, or the estimated cost of capital, from equity funds, during the construction period. During the years ended December 31, 2017, 2016, and 2015, Rockies Express recognized AFUDC associated with the estimated cost of capital from equity funds of approximately $0.5 million, $24.8 million, and $6.5 million, respectively, recorded as "Other income, net" on the accompanying statements of income.

Revenue Recognition

Rockies Express provides various types of natural gas transportation services to its customers in which the natural gas remains the property of these customers at all times. In many cases (generally described as "firm service"), the customer pays a two-part rate that includes (i) a fixed-fee reserving the right to transport natural gas in Rockies Express' facilities and (ii) a per-unit rate for volumes actually transported. The fixed-fee 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. 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 the discretion of Rockies Express 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 transported under firm service agreements.

In addition to its "firm" and "interruptible" transportation services, Rockies Express also provides a natural gas park and loan service to assist customers in managing a short-term gas surplus or deficit and a pooling and wheeling service to assist customers in the aggregation of gas supply from physical point(s) within a specified hub to a central pooling point and the re-delivery of gas supply to physical points within the same hub. Revenues are recognized as services are provided, in accordance with the terms negotiated under these contracts.

Rockies Express recognizes revenue from natural gas sales when the natural gas is sold at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured.

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt are deferred and amortized over the related financing period using the effective interest method. Deferred financing costs associated with long-term debt are presented as a reduction to the corresponding debt on the accompanying balance sheets. Deferred financing costs associated with revolving credit facilities or lines of credit are classified as noncurrent assets on the accompanying balance sheets.

Deferred Charges and Deferred Credits

Rockies Express has $2.5 million remaining of an initial $20.0 million deferred charge and deferred credit relating to a customer contract. The deferred charge is being amortized using a straight-line-method over the life of the related contract. Amortization of the deferred charge for each of the years ended December 31, 2017, 2016, and 2015 was $2.0 million and is included within transportation services revenues in the accompanying statements of income. The deferred credit is payable over a period of 10 years.

Environmental Matters

Rockies Express expenses or capitalizes, as appropriate, environmental expenditures that relate to current operations. Rockies Express expenses amounts that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation. Rockies Express does not discount environmental liabilities to a net present value, and records environmental liabilities when environmental assessments and/or remedial efforts are probable and costs can be reasonably estimated. Generally, recording of these accruals coincides with the completion of a feasibility study or a commitment to a formal plan of action.

Fair Value

Fair value, as defined in the fair value measurement accounting guidance, 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. The fair value measurement accounting guidance requires that Rockies Express 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 an 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. The fair value of current financial assets and liabilities approximate their reported carrying amounts as of December 31, 2017 and 2016.

Income Taxes

Rockies Express is a limited liability company that has elected to be treated as a partnership for income tax purposes. Accordingly, no provision for federal or state income taxes has been recorded in the financial statements of Rockies Express and the tax effects of Rockies Express' activities accrue to its Members.

New Accounting Pronouncements

Revenue Recognition

In May 2014, the FASB issued Accounting Standards Update ("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.

Throughout 2015 and 2016, the FASB has issued a series of subsequent updates to the revenue recognition guidance in Topic 606, including ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients, and ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers.

The amendments in ASU 2014-09, ASU 2016-08, ASU 2016-10, ASU 2016-12, and ASU 2016-20 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.

Management has completed its evaluation and implemented the revised guidance using the modified retrospective method as of January 1, 2018. This approach allows Rockies Express to apply the new standard to (i) all new contracts entered into after January 1, 2018 and (ii) all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of January 1, 2018 through a cumulative adjustment to members' equity. Consolidated revenues presented in the comparative financial statements for periods prior to January 1, 2018 will not be revised.

On January 1, 2018, Rockies Express recorded a cumulative effect adjustment to equity of $125.2 million. The cumulative effect adjustment arose as a result of the allocation of the transaction price to a series of individual performance obligations in certain long-term transportation contracts with tiered-pricing arrangements. Rockies Express established a contract asset on January 1, 2018 that reflects the amount by which the revenue that would have been recognized pursuant to ASC 606 exceeds the actual cash collected from the customer for periods prior to implementation and will be reversed over the remaining term of the contract.

Rockies Express anticipates significant changes to its disclosures based on the additional requirements prescribed by the standard. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is (or will be) recognized and data related to contract assets and liabilities. Additionally, Rockies Express continues to provide internal training and awareness related to the revised guidance to key stakeholders throughout the organization and evaluate business processes, systems and controls to ensure the accuracy and timeliness of the recognition and disclosure requirements under the new revenue guidance.

ASU No. 2016-02, "Leases (Topic 842)"

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). ASU 2016-02 provides a comprehensive update to the lease accounting topic in the Codification intended to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The amendments in ASU 2016-02 include a revised definition of a lease as well as certain scope exceptions. The changes primarily impact lessee accounting, while lessor accounting is largely unchanged from previous GAAP.

Management is currently evaluating the impact of Rockies Express' pending adoption of the revised guidance. The status of its implementation is as follows:

- Rockies Express management has formed an implementation team that meets to discuss implementation challenges, technical interpretations, industry-specific treatment of certain contract types, and project status.
- Rockies Express management is in the process of gathering data and reviewing contracts in order to identify all impacted contracts.
- Rockies Express management is evaluating the potential information technology and internal control changes that will be required for adoption based on the findings from its contract review process.
- Rockies Express management plans to provide internal training and awareness related to the revised guidance to the key stakeholders throughout its organization.

The amendments in ASU 2016-02 are effective for public entities for annual reporting periods beginning after December 15, 2018, and for interim periods within that reporting period. Early application is permitted. Rockies Express is currently evaluating the impact of ASU 2016-02. While the SEC has indicated that it will not object to certain public business entities adopting the standard using the timeline otherwise afforded to private companies, Rockies Express expects to adopt the new standard on January 1, 2019.

3. Property, Plant and Equipment

Rockies Express' property, plant and equipment, net consisted of the following:

	December 31,	
	2017	2016
	(in millions)	
Natural gas pipelines	$ 7,661.2	$ 7,085.8
General and other	15.4	9.9
Construction work in progress	11.9	503.2
Accumulated depreciation and amortization	(1,749.3)	(1,535.2)
Total property, plant and equipment, net	$ 5,939.2	$ 6,063.7

Depreciation expense was approximately $218.4 million, $204.3 million and $199.4 million for the years ended December 31, 2017, 2016 and 2015, respectively. Capitalized interest was $0.2 million, $9.3 million, and $2.8 million for the years ended December 31, 2017, 2016 and 2015, respectively.

4. Financing

Debt

Total outstanding debt as of December 31, 2017 and 2016 consisted of the following:

	December 31,	
	2017	2016
	(in millions)	
6.85% senior notes due July 15, 2018	$ 550.0	$ 550.0
6.00% senior notes due January 15, 2019	525.0	525.0
5.625% senior notes due April 15, 2020	750.0	750.0
7.50% senior notes due July 15, 2038	250.0	250.0
6.875% senior notes due April 15, 2040	500.0	500.0
Less: Unamortized debt discount and deferred financing costs	(10.2)	(13.3)
Total debt	2,564.8	2,561.7
Less: Current portion	(550.0)	—
Total long-term debt	$ 2,014.8	$ 2,561.7

Rockies Express Senior Notes

The senior notes issued by Rockies Express are redeemable in whole or in part, at Rockies Express' option at any time, at redemption prices defined in the associated indenture agreements.

All payments of principal and interest with respect to the fixed rate senior notes are the sole obligation of Rockies Express. Note holders have no recourse against Rockies Express' Members or their respective officers, directors, employees, shareholders, members, managers, unit holders or affiliates for any failure by Rockies Express to perform or comply with its obligations pursuant to the notes or the indenture. As of December 31, 2017, Rockies Express was in compliance with the covenants required under the senior notes.

Maturities of Debt

The scheduled maturities of Rockies Express' outstanding debt balances as of December 31, 2017 are summarized as follows (in millions):

Year	Scheduled Maturities
2018	$ 550.0
2019	525.0
2020	750.0
2021	—
2022	—
Thereafter	750.0
Total scheduled maturities	2,575.0
Unamortized debt discount and deferred financing costs	(10.2)
Total debt	$ 2,564.8

Rockies Express has senior notes scheduled to mature within one year of the issuance of these financial statements totaling $1.075 billion. Management has obtained a letter of support from the Members of Rockies Express confirming the Members' intent and ability to provide Rockies Express with financial support through at least one year and a day beyond February 13, 2018 (the financial statement issuance date) to the extent that other sources of funding are not otherwise available to Rockies Express. This support from the Members effectively alleviates the risk surrounding the ability of Rockies Express to continue as a going concern.

Rockies Express Revolving Credit Facility

On October 1, 2015, Rockies Express entered into a $150 million senior unsecured revolving credit facility ("the revolving credit facility") with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of lenders, which will mature on January 31, 2020. The revolving credit facility includes a $75 million sublimit for letters of credit and a $20 million sublimit for swing line loans and may be used for working capital and general company purposes. The revolving credit facility also contains an accordion feature whereby Rockies Express can increase the size of the credit facility to an aggregate of $200 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions precedent. As of December 31, 2017, there were no outstanding borrowings or letters of credit issued under the revolving credit facility.

Borrowings under the credit facility bear interest, at Rockies Express' 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 borrowings bearing interest based on the base rate, the applicable margin was initially 1.00%, and for loans bearing interest based on the reserve adjusted Eurodollar rate, the applicable margin was initially 2.00%. After the first full fiscal quarter, the applicable margin ranges from 0.50% to 1.25% for base rate borrowings and 1.50% to 2.25% for reserve adjusted Eurodollar rate borrowings, based upon Rockies Express' total leverage ratio. The unused portion of the credit facility is subject to a commitment fee, which ranges from 0.20% to 0.45% based upon Rockies Express' total leverage ratio.

Rockies Express has the option to have the applicable margin determined based on Rockies Express' credit ratings should Rockies Express receive an investment grade credit rating from one or more of the ratings agencies in the future. If Rockies Express were to make an election to exercise this option, the applicable margin would range from 0.125% to 1.00% for base rate borrowings and 1.125% to 2.00% for reserve adjusted Eurodollar borrowings, based on Rockies Express' credit ratings. Under such an election, the commitment fee would range from 0.125% to 0.40%, also based on Rockies Express' credit ratings.

The revolving credit facility generally requires Rockies Express to comply with various affirmative and negative covenants, including a limit on the leverage ratio (as defined in the credit agreement) of Rockies Express and restrictions on:

- incurring secured indebtedness;
- entering into mergers, consolidations and sales of assets;
- granting liens;
- entering into transactions with affiliates; and
- making restricted payments.

As of December 31, 2017, Rockies Express was in compliance with the covenants required under the revolving credit facility.

Repayment of 3.90% Senior Notes

The board of directors of Rockies Express approved repayment of the $450 million 3.90% senior notes due April 15, 2015 ("2015 Notes") which was financed through capital contributions by the Members of Rockies Express in proportion to their respective ownership interests. The capital contribution was made by each Member of Rockies Express in accordance with Section 4.3.1 of Rockies Express' Second Amended and Restated Limited Liability Company Agreement, as amended, and was used to repay the 2015 Notes on April 15, 2015.

Fair Value

The following table sets forth the carrying amount and fair value of Rockies Express' debt, which is not measured at fair value in the accompanying balance sheets as of December 31, 2017 and 2016, 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 millions)				
December 31, 2017	$ —	$ 2,752.1	$ —	$ 2,752.1	$ 2,564.8
December 31, 2016	$ —	$ 2,684.9	$ —	$ 2,684.9	$ 2,561.7

The debt is carried at amortized cost, net of deferred financing costs. The estimated fair value of Rockies Express' outstanding private placement debt is based upon quoted market prices adjusted for illiquid markets. Rockies Express is not aware of any factors that would significantly affect the estimated fair value subsequent to December 31, 2017.

5. Members' Equity

During the years ended December 31, 2017, 2016, and 2015, Rockies Express made distributions to Members of $669.9 million, $471.6 million, and $499.0 million, respectively. The distributions paid by Rockies Express during the year ended December 31, 2017 included a distribution of the proceeds from the Ultra settlement discussed in Note 10 – *Legal and Environmental Matters.*

During the years ended December 31, 2017, 2016, and 2015, Rockies Express received contributions from Members of $92.0 million, $304.9 million, and $733.1 million, respectively. Contributions from Members during the years ended December 31, 2017 and 2016 were primarily used to fund the construction and other costs of the Zone 3 Capacity Enhancement project, as discussed in Note 9 – *Regulatory Matters*. Contributions from Members during the year ended December 31, 2015 were used to repay the 2015 Notes, as discussed in Note 4 – *Financing*, fund the construction and other costs of the Zone 3 East-to-West Project facilities and the Zone 3 Capacity Enhancement project and remaining costs associated with the Seneca Lateral Project facilities, and to increase cash on hand for working capital needs.

Additional contributions and distributions were made subsequent to December 31, 2017. For details see Note 11 – *Subsequent Events*.

6. Related Party Transactions

Rockies Express has an operating agreement with Tallgrass NatGas Operator, LLC ("NatGas"), a subsidiary of TEP, under which NatGas provides and bills Rockies Express for various services at cost including employee labor costs, information technology services, employee health and retirement benefits, and insurance for property and casualty risks. In addition, NatGas receives a management oversight fee in the amount of 1% of Rockies Express' earnings before interest, taxes, depreciation, and amortization. Rockies Express' practice is to settle receivable and payable balances that exist with affiliates in the following month.

Totals of significant transactions with affiliated companies are as follows:

	Years Ended December 31,		
	2017	2016	2015
		(in millions)	
Revenues: Transportation services [1]	$ —	$ 14.4	$ 10.8
Charges from TD:			
Compensation, benefits and other charges	$ 18.6	$ 20.6	$ 18.5
General and administrative charges from affiliate	$ 8.9	$ 9.4	$ 8.6
Management Fees:			
Tallgrass NatGas Operator, LLC	$ 8.5	$ 6.2	$ 6.3

(1) Transportation services revenue for the years ended December 31, 2016 and 2015 is primarily from Sempra Energy prior to the May 6, 2016 sale of Sempra Energy's ownership to TEP REX.

Balances with affiliated companies included in the accompanying balance sheets are as follows:

	December 31,	
	2017	2016
	(in millions)	
Payables to affiliated companies:		
TD	$ 2.3	4.5
TEP	1.3	0.6
Total payables to affiliated companies	$ 3.6	$ 5.1

Gas imbalances with affiliated shippers are as follows:

	December 31,	
	2017	2016
	(in millions)	
Affiliate gas imbalance receivables	$ 0.4	$ —
Affiliate gas imbalance payables	$ —	$ 0.2

7. Commitments and Contingent Liabilities

Leases

Total rental expense under operating leases was $29.2 million for the years ended December 31, 2017, 2016, and 2015. Future minimum commitments related to these leases as of December 31, 2017 are as follows (in millions):

Year	Future Minimum Lease Payments
2018	$ 29.2
2019	29.2
2020	29.2
2021	29.2
2022	29.2
Thereafter	146.0
Total	$ 292.0

The future minimum rental commitments are primarily attributable to a 20-year capacity lease agreement with Overthrust Pipeline Company ("Overthrust") which commenced on January 1, 2008. The capacity lease provides the right to transport on a firm basis 625 MMcf/d of natural gas through Overthrust's system from either the Williams Field Services Opal Processing Plant or the TEPPCO Pioneer Processing Plant to the Wamsutter interconnect.

Capital Expenditures

Approximately $7.7 million of Rockies Express' capital expenditure budget for 2018 had been committed for purchases of property, plant and equipment at December 31, 2017.

8. Major Customers

During 2017, three non-affiliated shippers accounted for $169.4 million (20%), $111.9 million (13%), and $101.3 million (12%), respectively of Rockies Express' total revenues. During 2016, four non-affiliated shippers accounted for $164.8 million (23%), $82.9 million (12%), $71.4 million (10%), and $70.4 million (10%), respectively of Rockies Express' total revenues. During 2015, three non-affiliated shippers accounted for $187.6 million (24%), $163.0 million (21%), and $104.6 million (13%), respectively of Rockies Express' total revenues. Rockies Express attempts to mitigate credit risk by seeking collateral or financial guarantees and letters of credit from customers.

9. Regulatory Matters

There are no regulatory proceedings challenging the transportation rates of Rockies Express. Rockies Express has made certain regulatory filings with the FERC, including the following:

Petition for Declaratory Order – FERC Docket No. RP13-969-000

In June 2013, in Docket No. RP13-969-000, Rockies Express filed with the FERC a Petition for Declaratory Order which sought a ruling that the "most favored nations" or "MFN" provisions contained in Rockies Express' negotiated rate agreements ("NRAs") with its Foundation and Anchor Shippers would not prevent Rockies Express from providing firm transportation service at rates lower than Foundation and Anchor Shippers' rates that (1) have an east-to-west primary path; (2) are for a term of one year or longer; and (3) are limited to service in one rate zone and therefore do not utilize all of the same facilities or rate zones as the service provided pursuant to the Foundation and Anchor Shipper NRAs. In November 2013, the FERC issued a declaratory order finding that the potential transactions would not trigger the MFN rights of Rockies Express' Foundation and Anchor Shippers. Various parties filed requests for rehearing of the FERC's declaratory order.

In September 2014 and December 2015, the FERC accepted amended contracts with the shippers holding MFN rights on Rockies Express, which reflect the terms of settlements between these shippers and Rockies Express. The settlements provide additional clarity with respect to the applicability of the settling shippers' MFN rights, sharing by Rockies Express of certain transportation revenues, and the withdrawal of the settling shippers from the Petition for Declaratory Order proceeding. On September 27, 2017, FERC issued an order denying the requests for rehearing of the declaratory order issued in November 2013, and no party sought judicial appeal of the FERC order denying rehearing within the statutory deadline.

2015 Annual FERC Fuel Tracking Filings - FERC Docket No. RP15-584-000

On February 27, 2015, Rockies Express made its annual fuel tracker filing with a proposed effective date of April 1, 2015 in Docket No. RP15-584-000. This filing incorporated the revised fuel and lost and unaccounted-for and power cost tracker mechanisms filed in Docket No. RP14-1003. The FERC issued an order accepting the filing on March 26, 2015 and on April 9, 2015, accepted an errata to the February 27, 2015 filing reflecting a corrected rate for the Cheyenne Booster rate (PCT Reimbursement Charge).

Seneca Lateral Facilities Conversion – FERC Docket No. CP15-102-000

On March 2, 2015 in Docket No. CP15-102-000, Rockies Express filed with the FERC an application for (1) authorization to convert certain existing and operating pipeline and compression facilities located in Noble and Monroe Counties, Ohio (Seneca Lateral Facilities described in Docket Nos. CP13-539-000 and CP14-194-000) from Natural Gas Policy Act of 1978 Section 311 authority to NGA Section 7 jurisdiction, and (2) issuance of a certificate of public convenience and necessity authorizing Rockies Express to operate and maintain the Seneca Lateral Facilities. On April 7, 2016, the FERC issued a Certificate to Rockies Express granting its requested authorizations and on June 1, 2016 Rockies Express commenced NGA service on the Seneca Lateral.

Rockies Express Zone 3 Capacity Enhancement Project – FERC Docket No. CP15-137-000

On March 31, 2015 in Docket No. CP15-137-000, Rockies Express filed with the FERC an application for authorization to construct and operate (1) three new mainline compressor stations located in Pickaway and Fayette Counties, Ohio and Decatur County, Indiana; (2) additional compressors at an existing compressor station in Muskingum County, Ohio; and (3) certain ancillary facilities. The facilities increased the Rockies Express Zone 3 east-to-west mainline capacity by 0.8 Bcf/d. Pursuant to the FERC's obligations under the National Environmental Policy Act, FERC staff issued an Environmental Assessment for the project on August 31, 2015. On February 25, 2016, the FERC issued a Certificate of Public Convenience and Necessity authorizing Rockies Express to proceed with the project. On March 14, 2016, Rockies Express commenced construction of the project facilities. The project was placed in-service for the full 0.8 Bcf/d on January 6, 2017.

2016 Annual and Interim FERC Fuel Tracking Filings - FERC Docket Nos. RP16-702 and RP17-240

On March 1, 2016, Rockies Express made its annual fuel tracker filing with a proposed effective date of April 1, 2016 in Docket No. RP16-702. The FERC issued an order accepting the filing on March 25, 2016. On December 1, 2016, Rockies Express made an interim fuel tracker filing with a proposed effective date of January 1, 2017 in Docket No. RP17-240. The FERC issued an order accepting the filing on December 29, 2016.

Electric Power Charge Clarification - FERC Docket No. RP17-285

On December 21, 2016, in Docket No. RP17-285, Rockies Express proposed certain revisions to the General Terms and Conditions of its tariff to clarify that the electric power costs associated with the operation of gas coolers installed in association with the Zone 3 Capacity Enhancement Project, at both electric and gas powered stations, will be included in the Power Cost Tracker. Several shippers submitted comments on the proposal. The FERC issued an order on January 19, 2017 accepting the proposed revisions permitting the recovery of electric power costs from the operation of both gas and electric powered compressor stations, subject to certain clarifications.

2017 Annual and Interim FERC Fuel Tracking Filings - FERC Docket Nos. RP17-401 and RP17-1064

On February 13, 2017,in Docket No. RP17-401, Rockies Express made its annual fuel and power cost tracker filing with a proposed effective date of April 1, 2017. The FERC issued an order accepting the filing, including certain requested waivers, on March 21, 2017. On September 20, 2017, Rockies Express made its interim fuel tracker filing in Docket No. RP17-1064 with a proposed effective date of November 1, 2017. The FERC issued an order accepting the filing on October 18, 2017.

Increased Frequency of FL&U and PCT Adjustments - FERC Docket No. RP18-228

On December 1, 2017, in Docket No. RP18-228, Rockies Express made a filing with the FERC to increase the frequency in which it may adjust fixed fuel and lost and unaccounted for retainages and power cost tracker charges during the year so that its recovery of fixed fuel and lost and unaccounted for charges and power costs more closely track usage. Rockies Express proposed an effective date of April 1, 2018. The comment period ended on December 13, 2017, and no parties opposed Rockies Express' filing. The matter is pending before the FERC.

10. Legal and Environmental Matters

Legal

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

Rockies Express has evaluated claims in accordance with the accounting guidance for contingencies that it deems both probable and reasonably estimable and, accordingly, has recorded no reserve for legal claims as of December 31, 2017 or 2016.

Mineral Management Service Lawsuit

On June 30, 2009, Rockies Express filed claims against Mineral Management Service, a former unit of the U.S. Department of Interior (collectively "Interior") for breach of its contractual obligation to sign transportation service agreements for pipeline capacity that it had agreed to take on Rockies Express. The Civilian Board of Contract Appeals ("CBCA") conducted a trial and ruled that Interior was liable for breach of contract, but limited the damages Interior was required to pay. On September 13, 2013, the United States Court of Appeals for the Federal Circuit issued a decision affirming that Interior was liable for its breach of contract, but reversing the CBCA's decision to limit damages. The case was remanded to the CBCA for the purpose of calculating damages at a hearing. On May 20, 2016, Rockies Express and Interior agreed to resolve the claims in this matter in exchange for a $65 million cash payment to Rockies Express. Interior paid the amount due Rockies Express on June 23, 2016.

Ultra Resources

In early 2016, Ultra Resources, Inc. ("Ultra") defaulted on its firm transportation service agreement for approximately 0.2 Bcf/d through November 11, 2019. In late March 2016, Rockies Express terminated Ultra's service agreement. On April 14, 2016, Rockies Express filed a lawsuit against Ultra for breach of contract and damages in Harris County, Texas, seeking approximately $303 million in damages and other relief. On April 29, 2016, Ultra and certain of its debtor affiliates filed for protection under Chapter 11 of the United States Bankruptcy Code in United States Bankruptcy Court for the Southern District of Texas, which operated as a stay of the Harris County state court proceeding.

On January 12, 2017, Rockies Express and Ultra entered into an agreement to settle Rockies Express' approximately $303 million claim against Ultra. In accordance with the settlement agreement, Ultra made a cash payment to Rockies Express of $150 million on July 12, 2017, and entered into a new, seven-year firm transportation agreement with Rockies Express commencing December 1, 2019, for west-to-east service of 0.2 Bcf/d at a rate of approximately $0.37 per dth/d, or approximately $26.8 million annually.

Michels Corporation

On June 17, 2014, Michels Corporation ("Michels") filed a complaint and request for relief against Rockies Express in the Court of Common Pleas, Monroe County, Ohio, as a result of work performed by Michels to construct the Seneca Lateral Pipeline in Ohio. Michels sought unspecified damages from Rockies Express and asserted claims of breach of contract, negligent misrepresentation, unjust enrichment and quantum meruit. Michels also filed notices of Mechanic's Liens in Monroe and Noble Counties, asserting $24.2 million as the amount due.

On February 2, 2017, Rockies Express and Michels agreed to resolve Michels' claims for a $10 million cash payment by Rockies Express. The cash payment was inclusive of approximately $5.9 million that Rockies Express had been withholding from Michels. Subsequently, Rockies Express and Michels entered into a definitive agreement with respect to the settlement and Rockies Express made the $10 million cash payment to Michels on February 16, 2017.

Environmental, Health and Safety

Rockies Express is subject to a variety of federal, state and local laws that regulate permitted activities relating to air and water quality, waste disposal, and other environmental matters. Rockies Express believes that compliance with these laws will not have a material adverse impact on its 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 Rockies Express to incur significant costs.

11. Subsequent Events

Subsequent events, which are events or transactions that occurred after December 31, 2017 through the issuance of the accompanying financial statements, have been evaluated through February 13, 2018.

Members' Equity

Rockies Express paid distributions of $43.9 million to its Members and received contributions from its Members of $1.3 million in January 2018.

Seneca Lateral

On January 31, 2018, Rockies Express experienced an operational disruption on its Seneca Lateral due to a pipe rupture and natural gas release in a rural area in Noble County, Ohio. There were no injuries reported and no evacuations, however, the release required Rockies Express to shut off the flow through the segment. Repairs are underway to return the segment to service as soon as possible and a root cause investigation is ongoing.

(2) Financial Statement Schedules

All schedules are omitted because they are either not applicable or the required information is shown in the Consolidated Financial Statements or notes thereto included in Item 8 of this Form 10-K.

(3) Exhibits

Exhibit No.	**Description**
3.1	Certificate of Limited Partnership of Tallgrass Energy Partners, LP, dated as of February 6, 2013 (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, dated as of February 7, 2013 (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, dated as of February 6, 2013 (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 4, 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).
3.8	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Tallgrass Energy Partners, LP, dated as of December 28, 2017 (incorporated by reference to Exhibit 3.1 to the Partnership's Current Report on Form 8-K filed on December 28, 2017).
4.1	Indenture, dated September 1, 2016, among Tallgrass Energy Partners, LP, Tallgrass Energy Finance Corp., the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K filed on September 1, 2016).
4.2	Form of 5.50% Senior Note (included as Exhibit A in Exhibit 4.1 which is incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K filed on September 1, 2016).
4.3	Indenture, dated September 15, 2017, among Tallgrass Energy Partners, LP, Tallgrass Energy Finance Corp., the Guarantors named therein and U.S. Bank National Association, as trustee. (incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K filed on September 15, 2017).
4.4	Form of 5.50% Senior Note (included as Exhibit A in Exhibit 4.1 which is incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K filed on September 15, 2017).
10.1	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).
10.2†	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).
10.3†	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 18, 2013).
10.4†	Second Amended and Restated Employment Agreement, dated November 2, 2016, by and among Tallgrass Management, LLC, Tallgrass Energy Holdings, LLC, Tallgrass Equity, LLC, Tallgrass MLP GP, LLC, TEGP Management, LLC and David G. Dehaemers, Jr. (incorporated by reference to Exhibit 10.4 to the Partnership's Annual Report on Form 10-K filed on February 15, 2017).

10.5	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).
10.6	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).
10.7	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).
10.8	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 (incorporated by reference to Exhibit 10.10 to the Partnership's Annual Report on Form 10-K filed on February 17, 2016).
10.9	Amendment No. 4 to Credit Agreement, dated as of April 27, 2016, 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 April 28, 2016).
10.10	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 (incorporated by reference to Exhibit 10.14 to the Partnership's Annual Report on Form 10-K filed on February 17, 2016).
10.11	Membership Interest Purchase Agreement, dated as of March 29, 2016, by and between Sempra REX Holdings, LLC and TEP REX Holdings, LLC (as successor by assignment to Rockies Express Holdings, LLC) (incorporated by reference to Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q filed on August 3, 2016).
10.12	Assignment and Assumption Agreement, dated as of May 6, 2016, by and among Rockies Express Holdings, LLC, TEP REX Holdings, LLC and, for the limited purposes set forth therein, Tallgrass Development, LP (incorporated by reference to Exhibit 10.3 to the Partnership's Quarterly Report on Form 10-Q filed on August 3, 2016).
10.13	Second Amended and Restated Limited Liability Company Agreement of Rockies Express Pipeline LLC, dated effective as of January 1, 2010, among Rockies Express Holdings, LLC (as successor by assignment to Kinder Morgan W2E Pipeline LLC), TEP REX Holdings, LLC (as successor by assignment to Sempra REX Holdings, LLC and P&S Project I, LLC), and P66REX LLC (f/k/a COPREX LLC) (incorporated by reference to Exhibit 10.4 to the Partnership's Quarterly Report on Form 10-Q filed on August 3, 2016).
10.14	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Rockies Express Pipeline LLC, dated effective as of November 13, 2012, among Kinder Morgan W2E Pipeline LLC, TEP REX Holdings, LLC (as successor by assignment to Sempra REX Holdings, LLC and P&S Project I, LLC), Rockies Express Holdings, LLC and P66REX LLC (f/k/a COPREX LLC) (incorporated by reference to Exhibit 10.5 to the Partnership's Quarterly Report on Form 10-Q filed on August 3, 2016).
10.15	Amendment No. 2 to Second Amended and Restated Limited Liability Company Agreement, dated effective as of May 5, 2016, among Sempra REX Holdings, LLC and P&S Project I, LLC, Rockies Express Holdings, LLC and P66REX LLC (incorporated by reference to Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q filed on August 3, 2016).
10.16	Purchase and Sale Agreement, dated as of January 1, 2017, 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 January 3, 2017).
10.17	Form of Employee Equity Participation Unit Agreement (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 10-Q filed on November 2, 2017).
12.1*	Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries of Tallgrass Energy Partners, LP.
23.1*	Consent of PricewaterhouseCoopers LLP on Consolidated Financial Statements of Tallgrass Energy Partners, LP and the effectiveness of Tallgrass Energy Partners, LP's internal control over financial reporting.
23.2*	Consent of PricewaterhouseCoopers LLP on Financial Statements of Rockies Express Pipeline LLC.
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).

Item 16. Form 10-K Summary

Not applicable.

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 13, 2018

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 13, 2018
/s/ Gary J. Brauchle Gary J. Brauchle	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 13, 2018
/s/ Gary D. Watkins Gary D. Watkins	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 13, 2018
/s/ Frank J. Loverro Frank J. Loverro	Director	February 13, 2018
/s/ Stanley de J. Osborne Stanley de J. Osborne	Director	February 13, 2018
/s/ Jeffrey A. Ball Jeffrey A. Ball	Director	February 13, 2018
/s/ John T. Raymond John T. Raymond	Director	February 13, 2018
/s/ William R. Moler William R. Moler	Director	February 13, 2018
/s/ Terrance D. Towner Terrance D. Towner	Director	February 13, 2018
/s/ Roy N. Cook Roy N. Cook	Director	February 13, 2018
/s/ Jeffrey R. Armstrong Jeffrey R. Armstrong	Director	February 13, 2018

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]				
	Year Ended December 31,				
	2017	2016	2015	2014	2013
Earnings from continuing operations before fixed charges:					
Pre-tax income from continuing operations before earnings from unconsolidated affiliates	$ 203,379	$ 220,358	$ 194,413	$ 64,169	$ 12,971
Fixed charges	87,791	51,306	25,437	11,626	13,360
Amortization of capitalized interest	80	65	66	35	—
Distributed earnings from unconsolidated affiliates	237,192	54,449	3,096	1,280	—
less: Capitalized interest	(964)	(471)	(811)	(1,025)	(242)
Earnings from continuing operations before fixed charges	$ 527,478	$ 325,707	$ 222,201	$ 76,085	$ 26,089
Fixed charges:					
Interest expense, net of capitalized interest	79,167	37,189	14,226	7,648	11,264
Capitalized interest	964	471	811	1,025	242
Estimate of interest within rental expense (33.3%)	3,148	10,032	8,615	1,574	109
Amortization of debt costs	4,512	3,614	1,785	1,379	1,745
Total fixed charges	$ 87,791	$ 51,306	$ 25,437	$ 11,626	$ 13,360
Ratio of earnings to fixed charges [2]	6.01	6.35	8.74	6.54	1.95

(1) TEP closed the acquisition of Trailblazer on April 1, 2014, the acquisition of a controlling 33.3% membership interest in Pony Express effective September 1, 2014, and the acquisitions of Terminals and NatGas effective January 1, 2017. As these acquisitions 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, the initial 33.3% of Pony Express, and Terminals and NatGas. TEP closed the acquisitions of an additional 33.3% and 31.3% membership interests in Pony Express effective March 1, 2015 and January 1, 2016, respectively, which represent transactions between entities under common control and acquisitions of noncontrolling interests. As a result, financial information for periods prior to March 1, 2015 and January 1, 2016 has not been recast to reflect the additional 33.3% and 31.3% membership interests.

(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.

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
TEP REX Holdings, LLC	Delaware
Tallgrass NatGas Operator, LLC	Delaware
Tallgrass Terminals, LLC	Delaware
Tallgrass Sterling Terminal, LLC	Delaware
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
BNN Great Plains, LLC	Delaware
Stanchion Energy, LLC	Delaware
Tallgrass Midstream Gathering, LLC	Colorado
Deeprock Development, LLC	Delaware
Tallgrass Crude Gathering, LLC	Delaware
Tallgrass Cheyenne Connector Holdings, LLC	Delaware
Cheyenne Connector, LLC	Delaware
Cheyenne Connector Pipeline, Inc.	Colorado
Buckhorn Energy Services, LLC	Delaware
Buckhorn SWD Solutions, LLC	Delaware
Tallgrass Operations, LLC	Delaware
Tallgrass Iron Horse Holdings, LLC	Delaware
Tallgrass Iron Horse Operator, LLC	Delaware
Iron Horse Pipeline, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Forms S-3/A (No. 333-210976), S-3 (No. 333-205781) and S-8 (No. 333-189417) of Tallgrass Energy Partners, LP, of our report dated February 13, 2018, 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 13, 2018

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Forms S-3/A (No. 333-210976), S-3 (No. 333-205781) and S-8 (No. 333-189417) of Tallgrass Energy Partners, LP, of our report dated February 13, 2018, relating to the financial statements of Rockies Express Pipeline LLC, which appears in this Form 10‑K of Tallgrass Energy Partners, LP.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 13, 2018

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 13, 2018

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 13, 2018

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, 2017, 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 13, 2018

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, 2017, 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 13, 2018

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.

TALLGRASS ENERGY PARTNERS

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

William R. Moler
Executive Vice President &
Chief Operating Officer

Gary J. Brauchle
Executive Vice President &
Chief Financial Officer

Christopher R. Jones
Vice President, General Counsel
& Secretary

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TRANSFER AGENT

American Stock Transfer and Trust

TICKER SYMBOL

NYSE:TEP

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