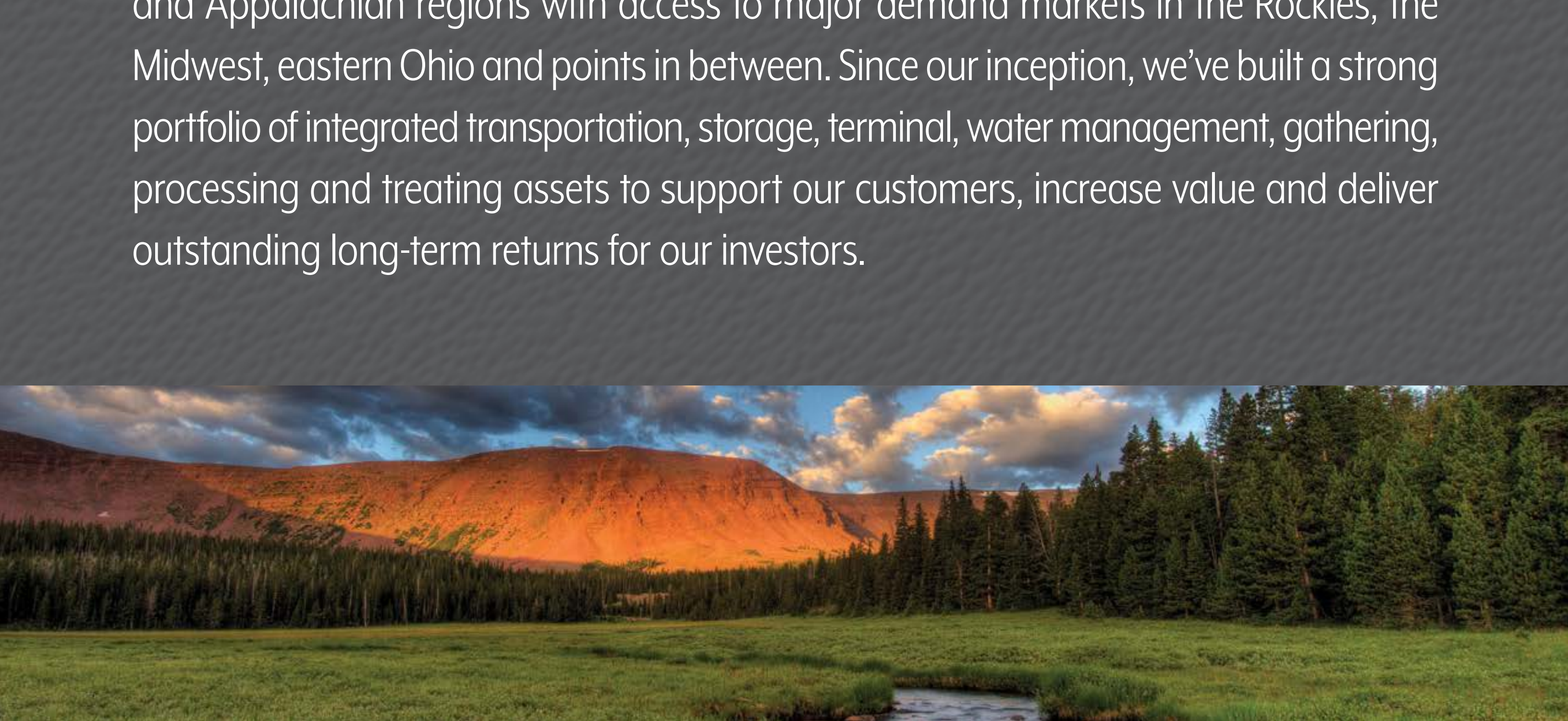
2018 ANNUAL REPORT

TALLGRASS ENERGY

Welcome to Tallgrass Energy.

We're a midstream infrastructure company, transporting crude oil and natural gas from some of the nation's most prolific basins in the Rocky Mountains, Upper Midwest and Appalachian regions with access to major demand markets in the Rockies, the Midwest, eastern Ohio and points in between. Since our inception, we've built a strong portfolio of integrated transportation, storage, terminal, water management, gathering, processing and treating assets to support our customers, increase value and deliver outstanding long-term returns for our investors.



In June 2018, Tallgrass closed on the merger of TEP and TEGP, consolidating from two public companies to one.

BENEFITS OF TALLGRASS COMBINATION

Reduced Complexity & Increased Alignment

- Tallgrass Energy has moved from 2 public companies to 1
- Full alignment among all equity owners
- 1099 Dividends (expect < 10% taxable)

Reduced Cost of Capital

- Elimination of IDRs provided immediate cost of capital improvement, enhancing the ability to grow through large projects and/or acquisitions
- Increased scale and reduced complexity could potentially improve Tallgrass' credit ratings, which would reduce cost of debt (positive watch from S&P and Investment Grade rating from Fitch)
- No cash federal taxes expected at TGE for at least 10 years

Increased Equity Market Depth

- TGE is a partnership taxed as a C-corp (1099 instead of K1)
- Larger pro forma market capitalization has increased liquidity and will likely appeal to a broader group of investors
- Will make future equity raises (if any) more efficient and cost-effective

CRUDE OIL	NATURAL GAS	NATURAL GAS	NATURAL GAS LIQUIDS	WATER
Pony Express Pipeline	Rockies Express Pipeline	Tallgrass Midstream Facilities	TMID NGL Pipeline	BNN Water Solutions
Powder River Express	Lease of Overthrust Pipeline Capacity	Tallgrass Midstream Gathering		
Oil Terminal	Tallgrass Interstate Gas Transmission			
Connected Third Party Refinery	TIGT Gas Storage Field			
	Trailblazer Pipeline Company			

2018 Key Accomplishments

MERGER

- TEP and TEGP merger

ACQUISITIONS

- Completed remaining dropdowns from Tallgrass Development
- Expanded oil footprint into the Powder River Basin
- Expanded terminal footprint
- Expanded water footprint into the Bakken

FINANCING

- Rockies Express Pipeline repaid debt and achieved investment grade credit ratings

THE YEAR IN REVIEW

With 2018 behind us, I want to take this opportunity to thank the truly outstanding employees at Tallgrass for delivering another remarkable year. Every day, the talented men and women at Tallgrass bring their passion and dedication to safely and reliably operating some of our nation's most critical energy infrastructure and executing the day-to-day activities that enable us to do the things we say we're going to do. It's humbling to lead this team.

In many ways, 2018 marked a brand-new chapter in Tallgrass' growth trajectory. We simplified our corporate structure to position Tallgrass for even greater long-term success. By closing on the merger of TEP and TEGP—a transaction that was overwhelmingly supported by TEP unitholders—we realized a number of important benefits and opened the door to an even more promising future.

We believe the combination reduced complexity, increased alignment among equity owners, reduced our cost of capital and increased equity market depth. Achieving these goals further strengthens our position as one of the nation's leading infrastructure companies.

Shortly after the merger, Tallgrass received an investment grade credit rating from Fitch. We believe Tallgrass has maintained investment grade credit metrics for several years, and it was gratifying to see that validated by Fitch. Rockies Express Pipeline, which continues its transformation into the nation's northernmost bi-directional natural gas header system, also received investment grade credit ratings from S&P and Fitch in 2018.

Our successful business development efforts and continued operational excellence translated into another year of strong financial results. In 2018, we covered our dividend by more than 1.25 times, generating almost $150 million of cash in excess of dividends paid. We exceeded the high end of the Adjusted EBITDA and met the high end of dividend growth guidance we provided in March 2018. At that time, we said we expected Adjusted EBITDA to be $755–$835 million[1] and dividend growth to be 38–42 percent for TGE. Pro Forma 2018 Adjusted EBITDA was $860 million and dividend growth for the year was 41.5 percent.

For Q4 2018, Tallgrass paid a quarterly cash dividend of $0.52 per Class A share, or $2.08 on an annualized basis. That marked Tallgrass' 14th consecutive increase since its May 2015 IPO. Moving forward, we expect to grow dividends by 6–8 percent on an annualized basis and grow free cash flow at a rate of 13–15 percent.

Now, let's take a look at some noteworthy accomplishments from 2018.

2018 HIGHLIGHTS

Corporate

- Acquired remaining drop-down assets from Tallgrass Development: 25 percent of REX bringing Tallgrass' ownership to 75 percent, and the remaining 2 percent of Pony Express.
- Tallgrass received an investment grade credit rating from Fitch.
- REX received investment grade credit ratings from S&P and Fitch.

Crude Oil Transportation Segment

- Reinforced our presence in the heart of the Powder River Basin through our Powder River Gateway joint venture, which owns the Iron Horse Pipeline, the Powder River Express Pipeline and crude oil terminal in Guernsey, Wyo., enabling Wyoming production to get onto Pony Express.
- Further strengthened our footprint in the D-J Basin by placing in service the Platteville Extension, which connects D-J producers to Pony Express via our Buckingham terminal and Northeast Colorado Lateral. We also began working on a separate extension to allow producers to connect to Pony Express via the Pawnee terminal.
- Increased Pony Express capacity to about 400,000 barrels per day through pump enhancements and in January 2019 announced plans for an additional 550,000 barrels per day through a joint venture with Kinder Morgan that includes converting portions of the Wyoming Intrastate and Cheyenne Plains natural gas pipeline systems and constructing approximately 200 miles of new pipeline.

Natural Gas Transportation Segment

- Tallgrass Interstate Gas Transmission and Trailblazer Pipeline continue to act as a solid foundation for the natural gas transportation segment from both a revenue and market presence perspective by serving key on-system markets and operating as the most economic route out of the Rockies, respectively. Both pipeline systems continue to optimize their capacity and revenue while pursuing opportunities associated with increased Rockies production.

(1) Excluding deficiency payments.

- » REX continues its evolution into the nation's northernmost header system with the Cheyenne Hub Enhancement (in-service anticipated Q4 2019), which will allow significant volumes to enter the pipeline at Cheyenne and flow to demand markets across the nation. In 2018, REX realized its longest duration of full utilization of west-to-east transport—emphasizing its value as an essential Rockies production takeaway.
- » REX connected its first two natural gas-fired power plants to the system, increasing the direct connected load to more than 1.4 Bcf/d, nearly two times the pipeline's original direct connects.
- » The natural gas transportation segment entered the D-J Basin with its submission of a FERC 7c Application for Tallgrass' first greenfield natural gas pipeline, Cheyenne Connector, which has an anticipated in-service of Q4 2019.

Gathering, Processing & Terminalling Segment

- » TALLGRASS TERMINALS
  - Began construction to connect several D-J Basin gathering companies into the Buckingham and Grasslands terminals, providing additional volumes for Pony Express.
  - Began construction on the Guernsey and Grasslands terminals, both of which are expected to be in service in the first half of 2019.
  - Placed the Natoma terminal in service in July, giving Central Kansas Uplift producers direct access to Pony.
  - Acquired a 51 percent interest in the Pawnee, Colo., terminal.
- » TMID
  - Connected an additional 29 wells to our processing facilities and secured commitments for another 33 future wells.
  - Executed an agreement to increase propane sales by 2 million gallons in 2019.
  - Renegotiated and/or renewed several contracts resulting in more favorable terms and executed incremental gathering and processing contracts for 2019.
- » WATER BUSINESS
  - Closed two Bakken acquisitions and expanded gathering and disposal infrastructure, establishing Tallgrass' footprint in the basin and making Tallgrass one of the largest water infrastructure companies in the Bakken.
  - Completed the installation of more than 75 miles of gathering pipeline and 72 pump stations to service a long-term contract in the Bakken.
  - Executed two long-term take-or-pay water supply contracts with major producers in the D-J Basin and expanded disposal capacity for existing clients in the Powder River and Permian basins.

THE NEXT CHAPTER

As we begin the next chapter of our evolution, you can expect us to move from a high-growth company to one of more measured growth, deploying capital at appropriate returns ("ROIC"). We will do this by building on our platform of core midstream assets through organic growth and acquisitions to expand into new basins and markets and continue to enhance value to all stakeholders—shareholders, customers, employees and the communities in which we operate.

As a traditional midstream operator transporting oil and gas from producing regions to demand markets across the country, we're well positioned to take advantage of two emerging trends. First, we're seeing a growing number of power generators converting from coal to natural gas. Not only is natural gas clean, reliable, abundant and affordable, but it also complements the increasing share of renewable generation by ensuring electric reliability to support these intermittent resources. Simply put, natural gas will continue to play a large role in power generation for years to come. In the first half of 2018, REX accomplished a milestone by connecting its first two natural gas-fired power plants, and we expect those connections to grow as power generators capitalize on REX's reliability and commitment to operational excellence.

In 2018, the U.S. achieved two milestones of its own: our nation became the world's largest oil producer, surpassing both Saudi Arabia and Russia, and became a net exporter of crude oil and petroleum products for the first time in almost 70 years. We expect both production and exports to continue their growth trajectory for at least the next decade.

As part of Tallgrass' strategic growth initiatives, in August we announced two separate projects to support the country's crude oil growth. The proposed 700-mile Seahorse Pipeline would transport crude oil from Cushing, Okla., to the Gulf in Louisiana, where it can be refined into critical products that fuel our economy, such as gasoline, jet fuel and heating oil, or exported to other countries. We also announced we have signed a binding agreement with an unaffiliated third party that has the potential to be an anchor shipper and equity partner in that project.

In addition, we announced plans to develop the Plaquemines Liquids Terminal in Louisiana. PLT is a joint development project with Drexel Hamilton Infrastructure Partners, LP, in concert with the Plaquemines Port & Harbor Terminal District (PPHTD), a Louisiana state agency. The proposed PLT project is a liquids export terminal facility on the Mississippi River in Plaquemines Parish, La., with the capacity of up to 20 million barrels of storage and the ability to fully load and unload Post-Panamax vessels on its deep-water dock. Tallgrass anticipates building a separate offshore pipeline extension that would give PLT the added capability of loading Very Large Crude Carriers by 3Q 2021.

At the end of January 2019, we announced an agreement under which Blackstone Infrastructure Partners would acquire a controlling interest in Tallgrass. We expect that transaction to close in Q1 2019. We believe Blackstone's scale, long-term capital and investment expertise across the energy industry make it an ideal partner as we continue our growth trajectory. Along with the projects we announced in 2018, our agreement with Blackstone advances the strategic plan we've charted for the future to solidify our position as a competitive midstream operator and further strengthen our ability to add value to our customers, our shareholders and other stakeholders.

Thanks again, to the outstanding Tallgrass team and to our customers, suppliers and shareholders for making all this possible. We look forward to what lies ahead.

Sincerely,

David G. Dehaemers Jr.
President and Chief Executive Officer

SUMMARY FINANCIAL INFORMATION

(in thousands, except coverage)	Year Ended December 31, 2018[1]
Net income	$ 455,934
Net income attributable to noncontrolling interestst	(235,167)
Net income attributable to TGE	220,767
Add:	
Interest expense, net	133,319
Depreciation and amortization expense[2]	109,708
Distributions from unconsolidated investments	387,148
Deficiency payments, net[2]	21,830
Non-cash compensation expense	10,666
Loss on debt retirement	2,245
Distributions received by Tallgrass Development[3]	11,475
Deferred income tax expense	67,446
Net income attributable to Exchange Right Holders	229,039
Less:	
Equity in earnings of unconsolidated investments	(306,819)
Gain on disposal of assets[2]	(10,659)
Non-cash gain related to derivative instruments[2]	(4,252)
Tallgrass Energy Adjusted EBITDA	$ 871,913
Less:	
Cash interest cost	(127,973)
Maintenance capital expenditures, net[2]	(20,956)
Cash Available for Dividends	722,984
Less:	
Dividends to Class A (TGE)	(266,389)
Dividends to Class B (Exchange Right Holders)	(251,715)
Distribution to TEP public unitholders	(46,391)
Amounts in excess of dividends	$ 158,489
Dividend coverage	1.28 x

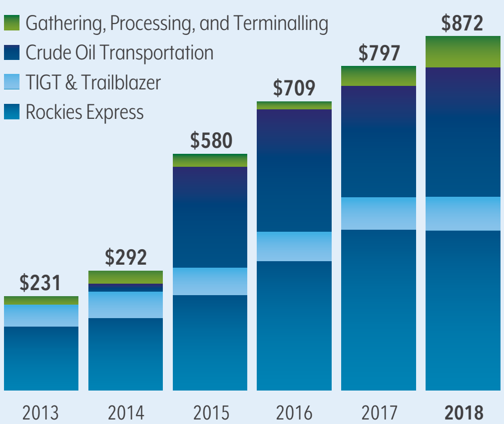
(1) Indicated amounts presented for the year ended Dec. 31, 2018, are on a pro forma basis assuming that the merger transaction with TEP had closed on Jan. 1, 2018.

(2) Net of noncontrolling interest in joint ventures.

(3) Represents distributions received by Tallgrass Development from its (i) 25.01 percent membership interest in REX from January 1, 2018 to February 6, 2018 and its (ii) 2 percent membership interest in Pony Express from January 1, 2018 to January 31, 2018.

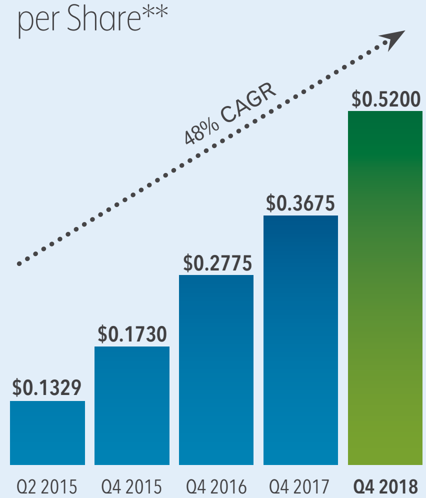
Tallgrass Energy Adjusted EBITDA*

(in millions)



**Represents Adjusted EBITDA across the Tallgrass Energy Family of Companies. A reconciliation of this non-GAAP metric for 2013–2017 is available in the presentation dated 10/9/2018 under the Webcasts & Presentations section at www.tallgrassenergy.com.*

TGE Dividends per Share**



***TGE Class A shareholders received a pro-rated dividend from TGE for the second quarter of 2015 in an amount of $0.073 for the period from May 12, 2015–June 30, 2015. For illustrative purposes, the chart above shows what the dividend would have been if TGE had been public for the entire quarter.*

TALLGRASS ENERGY

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, 2018
or

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

Commission file number 001-37365

Tallgrass Energy, LP
(Exact name of registrant as specified in its charter)

Delaware	**47-3159268**
(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
Class A Shares 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 every Interactive Data File required to be submitted 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 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.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	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 29, 2018, the last business day of the Registrant's most recently completed second fiscal quarter (based on the closing sale price of $22.16 of the Registrant's Class A shares, as reported by the New York Stock Exchange on such date) was approximately $1,264.2 million. On February 8, 2019, the Registrant had 156,353,761 Class A shares and 123,887,893 Class B shares outstanding.

TALLGRASS ENERGY, 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," "TGE" and similar terms refer to Tallgrass Energy, LP, in its individual capacity or to Tallgrass Energy, LP and its consolidated subsidiaries collectively (including Tallgrass Equity, TEP and their respective subsidiaries), as the context requires. References to "Tallgrass Equity" refer to Tallgrass Equity, LLC. References to "TEP" refer to Tallgrass Energy Partners, LP. The term our "general partner" refers to Tallgrass Energy 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 pay dividends to our Class A shareholders;
- our expected receipt of, and amounts of, distributions from Tallgrass Equity;
- our ability to complete and integrate acquisitions, including integrating the acquisitions discussed in Item 1.—Business, *"Acquisitions and Dispositions;"*
- the demand for our services, including natural gas transportation and storage; crude oil transportation; and natural gas gathering and processing, crude oil storage and terminalling services, and water business services;
- 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 governmental regulators of our assets, including the FERC;
- 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, 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 existing and 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

TGE is a limited partnership that owns, operates, acquires and develops midstream energy assets in North America and has elected to be treated as a corporation for U.S. federal income tax purposes.

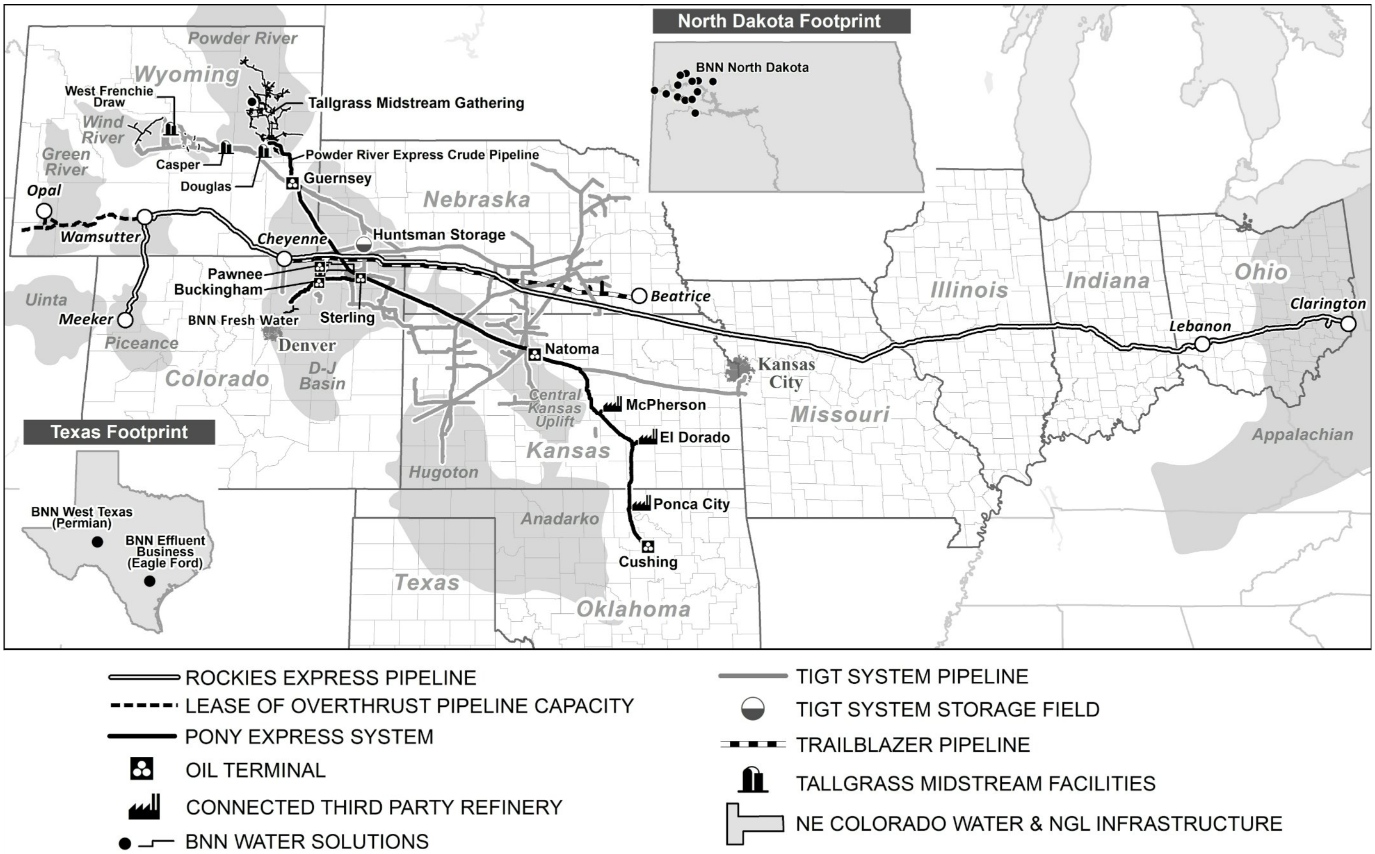
Our operations are conducted through, and our operating assets are owned by, our direct and indirect subsidiaries, including Tallgrass Equity, in which we directly own an approximate 55.79% membership interest as of February 8, 2019. We are located in and provide services to certain key United States 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 an integrated natural gas storage facility;
- Crude Oil Transportation—the ownership and operation of FERC-regulated crude oil pipeline systems; and
- Gathering, Processing & Terminalling—the ownership and operation of natural gas gathering and processing facilities; crude oil 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.

Our Assets

The following map shows our primary assets, which consist of natural gas transportation and storage assets; crude oil transportation assets; natural gas gathering and processing assets; crude oil storage 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 75% membership interest in Rockies Express Pipeline LLC ("Rockies Express"). Rockies Express 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, 2018, approximately 98% 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, 2018, 2017, and 2016 and as of December 31, 2018:

	Year Ended December 31,		
	2018	2017	2016
Approximate average daily deliveries (Bcf/d) [(1)]	4.4	4.3	3.2

	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%	14 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, 2018. 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 19 – *Legal and Environmental Matters.*

(3) Weighted by contracted capacity as of December 31, 2018. 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, 2018, approximately 94% 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, 2018, substantially all of the 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, 2018, 2017, and 2016 and as of December 31, 2018:

	Year Ended December 31,		
	2018	2017	2016
Approximate average daily deliveries (Bcf/d)	1.3	1.2	1.1

	Approximate Capacity	Total Firm Contracted Capacity (1)	Approximate % of Capacity Subscribed under Firm Contracts	Weighted Average Remaining Firm Contract Life (2)
Transportation	2.0 Bcf/d	1.6 Bcf/d	80%	5 years
Storage	15.974 Bcf (3)	11 Bcf	71%	4 years

(1) Reflects total capacity reserved under long-term firm fee contracts, including backhaul service, as of December 31, 2018.

(2) Weighted by contracted capacity as of December 31, 2018.

(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 System. We own a 100% membership interest in Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which provides crude oil transportation to customers in Wyoming, Colorado, Kansas, and the surrounding regions. Pony Express owns an approximately 834-mile crude oil pipeline commencing in both Guernsey, Wyoming and Weld County, Colorado and terminating in Cushing, Oklahoma, with delivery points at the McPherson, El Dorado and Ponca City refineries and in Cushing, Oklahoma (the "Pony Express System"). In the second quarter of 2018, Pony Express placed into service an extension of the system from an additional origin point in Weld County, Colorado located near Platteville, Colorado ("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's long-haul capacity as of December 31, 2018 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,		
			2018	2017	2016
342,000	93%	2 years	336,314	267,734	285,507

(1) Excludes additional capacity related to the ability to inject drag reducing agent, which is an additive that increases pipeline flow efficiency, and additional capacity related to expansion projects.

(2) We are required to make no less than 10% of design capacity available for non-contract, or "walk-up", shippers. Approximately 93% 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.

Powder River Gateway. In January 2019, we completed the expansion of our existing joint venture with Silver Creek Midstream, LLC ("Silver Creek") and acquired a 51% membership interest in Powder River Gateway, LLC ("Powder River Gateway"). Powder River Gateway owns the (i) Powder River Express Pipeline ("PRE Pipeline"), a 70-mile crude oil pipeline with a capacity of 90,000 barrels per day that transports crude oil from the Powder River Basin to Guernsey, Wyoming; (ii) Iron Horse Pipeline ("Iron Horse Pipeline"), a 80-mile crude oil pipeline expected to be placed into service in the second quarter of 2019 that will have an initial capacity of approximately 100,000 barrels per day and will transport crude oil from the Powder River Basin to Guernsey, Wyoming; and (iii) crude oil terminal facilities in Guernsey, Wyoming with approximately 370,000 barrels of crude storage currently in-service and over 1 million barrels of storage expected in the second quarter of 2019 once current construction of additional facilities is completed.

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"). 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 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, 2018, approximately 12%, 51%, and 37% of TMID's Adjusted EBITDA came from firm fee, volumetric fee, and commodity sensitive contracts, respectively.

The table below sets forth certain information regarding natural gas gathering and processing at the Midstream Facilities as of December 31, 2018 and for the years ended December 31, 2018, 2017, and 2016:

	Approximate Capacity (MMcf/d)	Approximate Average Volumes (MMcf/d) Year Ended December 31, 2018	2017	2016
Gathering	75	42	37 [1]	N/A
Processing	190 [2]	122	109	103

(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, a produced water disposal facility in Campbell County, Wyoming, and a produced water gathering and disposal system in North Dakota. 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 November 2018, Water Solutions acquired a 100% membership interest in NGL Water Solutions Bakken, LLC ("NGL Water Solutions Bakken"), which owns a produced water disposal system in the Bakken basin.

The table below sets forth certain information regarding the Water Solutions assets as of December 31, 2018 and for the years ended December 31, 2018, 2017, and 2016:

	Approximate Current Design Capacity (bbls/d)		Approximate Average Volumes (bbls/d) Year Ended December 31,		
			2018	2017	2016
Freshwater	170,863	(1)	17,849	69,139	13,201
Gathering and Disposal	271,500	(2)	98,489	31,511	11,307

(1) Represents design capacity at our BNN Western, LLC ("Western") owned facilities and our BNN Colorado freshwater storage reservoir and supply pipeline. 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, the West Texas produced water gathering and disposal system which commenced operations by Water Solutions in March 2016, the BNN North Dakota, LLC ("BNN North Dakota") produced water gathering and disposal system acquired in January 2018 and produced water disposal system acquired in November 2018.

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"), the crude oil terminal in Weld County, Colorado with four truck unloading skids capable of receiving up to 42,000 bbls per day (the "Buckingham Terminal"), and the crude oil terminal in the Central Kansas Uplift that can deliver upward of 20,000 bbls per day into the Pony Express System and commenced operations in the first quarter of 2018 (the "Natoma Terminal"). Terminals also owns an approximately 60% membership interest in Deeprock Development, LLC ("Deeprock Development"), which owns crude oil terminals in Cushing, Oklahoma with approximately 4.0 million bbls of storage capacity (the "Cushing Terminal"). In April 2018, Terminals acquired a 51% membership interest in the Pawnee, Colorado crude oil terminal ("Pawnee Terminal") with approximately 300,000 bbls of storage capacity.

Stanchion. We own a 100% membership interest in Stanchion Energy, LLC ("Stanchion"), which engages in the marketing of crude oil. Stanchion currently consists of three of our employees who primarily engage in the purchase and sale of crude oil.

Major Customers

For the year ended December 31, 2018, Continental Resources accounted for approximately 10% 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 is held by Tallgrass Energy GP, LLC, whose sole member is Tallgrass Energy Holdings, LLC ("Tallgrass Energy Holdings"). A group of persons, which we refer to as the Exchange Right Holders, collectively own all our outstanding Class B shares and an equivalent number of Tallgrass Equity units. The Exchange Right Holders are entitled to exercise the right to exchange their Tallgrass Equity units (together with an equivalent number of Class B shares) for Class A shares at an exchange ratio of one Class A share for each Tallgrass Equity unit exchanged. As of February 8, 2019, the Exchange Right Holders primarily consist of Kelso, EMG, and Tallgrass KC. Tallgrass KC refers to Tallgrass KC, LLC, which is an entity primarily owned by certain members of our management. Certain of the Exchange Right Holders collectively own 100% of the voting power of Tallgrass Energy Holdings.

On January 31, 2019, we announced that affiliates of Blackstone Infrastructure Partners (collectively, "BIP") had entered into a definitive purchase agreement with Kelso, EMG, and Tallgrass KC (collectively, the "Sellers"), pursuant to which BIP will acquire from the Sellers 100% of the membership interests in our general partner and an approximately 44% economic interest in us (the "Blackstone Acquisition"). One or more affiliates of GIC Special Investment Pte. Ltd. ("GIC SI"), the infrastructure and private equity arm of GIC Pte. Ltd., Singapore's sovereign wealth fund, will be a minority investor in the Blackstone Acquisition. The interests acquired in the Blackstone Acquisition will include all of the economic interests in us held by EMG and Kelso, and a substantial portion of the interests held by Tallgrass KC.

Subject to customary closing conditions, the Blackstone Acquisition is expected to close within the first quarter of 2019. Following consummation of the Blackstone Acquisition, (i) the Exchange Right Holders are expected to consist of BIP and certain members of our management and (ii) BIP will own 100% of the membership interests in our general partner.

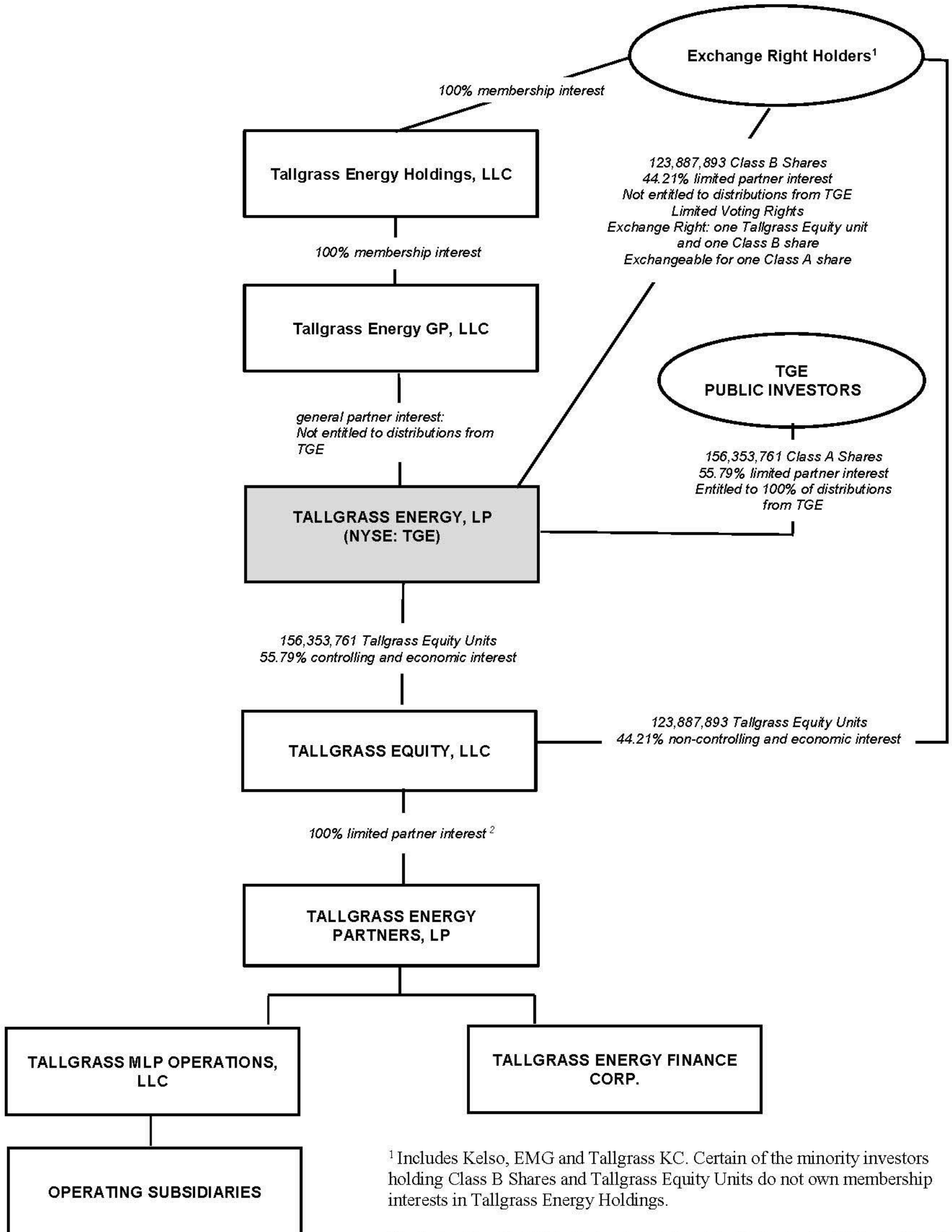
While we are structured as a limited partnership, (i) we have elected to be treated as a corporation for U.S. federal income tax purposes, (ii) neither our general partner nor the holders of our Class B shares are entitled to receive any dividends from us, and (iii) our capital structure does not include incentive distribution rights. Therefore, our dividends will be made exclusively to our Class A shares. However, holders of our Class A shares and Class B shares vote together as a single class on all matters presented to our shareholders for their vote or approval, except as otherwise required by applicable law or our partnership agreement. The term "shares" used in this annual report refers to both the Class A shares and Class B shares representing limited partner interests in us. References to our "shareholders" refer to the holders of our Class A and Class B shares.

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, as of February 8, 2019, Tallgrass Energy Holdings effectively controls our business and affairs through the exercise of its rights as the sole member of our general partner, including its right to appoint members to the board of directors of our general partner. Following consummation of the Blackstone Acquisition, BIP will, subject to certain contractual rights, exercise such control through the ownership of 100% of the membership interests in our general partner.

In connection with the closing of the initial public offering of our Class A shares (the "TGE IPO"), we, our general partner, Tallgrass Equity and Tallgrass Energy Holdings entered into an omnibus agreement (the "TGE Omnibus Agreement"), that addresses the following matters:

- Tallgrass Equity's obligation to reimburse Tallgrass Energy Holdings and its affiliates for expenses incurred (i) on our behalf, (ii) on behalf of our general partner and (iii) for any other purposes related to our business and activities or those of our general partner, including our public company expenses and general and administrative expenses; and
- Our use of the name "Tallgrass" and any associated or related marks.

The chart below shows the structure of Tallgrass Energy Holdings and its subsidiaries as of February 8, 2019 in a summary format.



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

[2] Includes (i) a 99.9% limited partner interest held directly by Tallgrass Equity, (ii) a 0.1% limited partner interest held indirectly through Tallgrass Equity Investments, LLC, a wholly owned subisidary of Tallgrass Equity, and (iii) a general partner interest held indirectly through TEP GP.

Previous Organizational Structure

We were initially formed in 2015 as part of a reorganization involving entities that were previously controlled by Tallgrass Equity to effect the TGE IPO. As of the closing of the TGE IPO in May 2015, our sole cash-generating asset was a controlling membership interest in Tallgrass Equity and Tallgrass Equity's sole cash-generating assets consisted of direct and indirect partnership interests in TEP, which was a publicly traded limited partnership at the time.

Prior to the February 2018 merger discussed below, Tallgrass Energy Holdings was the general partner of Tallgrass Development. Historically, TEP acquired a number of its assets from Tallgrass Development. In connection with TEP's initial public offering in May 2013 (the "TEP IPO"), Tallgrass Development contributed to TEP 100% of the membership interests in TIGT and TMID. Following the TEP IPO, TEP 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 owned certain administrative assets consisting primarily of information technology assets. In addition, in May 2016 Tallgrass Development assigned to TEP 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.

On February 7, 2018, Tallgrass Development merged into Tallgrass Development Holdings, a wholly-owned subsidiary of Tallgrass Equity, and as a result of the merger, Tallgrass Equity acquired a 25.01% membership interest in Rockies Express and an additional 5,619,218 TEP common units. As consideration for the acquisition, TGE and Tallgrass Equity issued 27,554,785 TGE Class B shares and Tallgrass Equity units, valued at approximately $644.8 million based on the closing price on February 6, 2018, to the limited partners of Tallgrass Development.

On March 26, 2018, we entered into an Agreement and Plan of Merger (the "Merger Agreement") with Tallgrass Equity, Tallgrass MLP GP, LLC, a Delaware limited liability company and the general partner of TEP ("TEP GP"), and Razor Merger Sub, LLC, a Delaware limited liability company. The merger transaction contemplated by the Merger Agreement (the "TEP Merger") was completed effective June 30, 2018, and as a result, 47,693,097 TEP common units held by the public were converted into the right to receive Class A shares of TGE at an exchange ratio of 2.0 Class A shares for each outstanding TEP common unit, TEP's incentive distribution rights were cancelled, TEP's common units ceased being publicly traded, and 100% of TEP's equity interests are now owned by Tallgrass Equity and its subsidiaries.

Acquisitions and Dispositions

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 and storage; crude oil transportation; and natural gas gathering and processing, crude oil storage and terminalling services, and water business service 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 completed in 2018 and in early 2019, as discussed in Note 3 – *Acquisitions and Dispositions* and Note 22 – *Subsequent Events*.

- *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. The transaction closed in April 2018.
- *BNN North Dakota.* In January 2018, we acquired a 100% membership interest in Buckhorn Energy Services, LLC and Buckhorn SWD Solutions, LLC, which were subsequently merged and renamed BNN North Dakota, LLC, for cash consideration of approximately $95 million.
- *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%.

- *Additional Membership Interest in Rockies Express and Additional TEP Common Units.* In February 2018, Tallgrass Development merged into Tallgrass Development Holdings, LLC, a wholly-owned subsidiary of Tallgrass Equity, and as a result of the merger, Tallgrass Equity acquired a 25.01% membership interest in Rockies Express and an additional 5,619,218 TEP common units. As consideration for the acquisition, TGE and Tallgrass Equity issued 27,554,785 TGE Class B shares and Tallgrass Equity units, valued at approximately $644.8 million. Subsequent to the closing of the transaction, our aggregate membership interest in Rockies Express is 75%.
- *Tallgrass Crude Gathering.* In February 2018, we entered into an agreement with an affiliate of Silver Creek to sell our 100% membership interest in Tallgrass Crude Gathering, LLC ("TCG") for approximately $50 million. The sale of TCG closed in February 2018.
- *Joint Venture with Silver Creek.* In February 2018, we entered into an agreement with Silver Creek to form Iron Horse Pipeline, LLC ("Iron Horse"), which owns the Iron Horse Pipeline currently under construction. In August 2018, we entered into an agreement with Silver Creek to expand the Iron Horse joint venture through the contribution by us and Silver Creek of cash and additional Powder River Basin assets. These additional contributions were completed in January 2019. The expanded joint venture operates under the name Powder River Gateway, LLC and owns the Iron Horse Pipeline, the PRE Pipeline, and crude oil terminal facilities in Guernsey, Wyoming. Effective January 1, 2019, we own a 51% membership interest in Powder River Gateway and operate the joint venture.
- *Acquisition of NGL Water Solutions Bakken.* In November 2018, we acquired 100% of the membership interests in NGL Water Solutions Bakken, which was subsequently merged into BNN North Dakota, for cash consideration of approximately $91 million, subject to working capital adjustments.

Growth Projects

Our extensive asset base and our relationships with customers provide us with opportunities for internal growth through the construction of additional assets that are complementary to, and expand or extend, our existing asset base. The following growth projects are currently ongoing and will extend throughout 2019 and beyond:

- *Iron Horse Pipeline.* Iron Horse Pipeline, an approximately 80-mile crude oil pipeline currently under construction, will have an initial capacity of approximately 100,000 barrels per day, expandable up to 200,000 barrels per day, to transport crude oil from the Powder River Basin to the Guernsey, Wyoming oil hub and is expected to be in-service in the second quarter of 2019. As discussed above, the Iron Horse Pipeline is part of the Powder River Gateway joint venture.
- *Grasslands Terminal.* We are currently constructing the Grasslands Terminal in Platteville, Colorado, which will connect to the Platteville Extension and enable Pony Express to batch multiple common streams out of Platteville. The Grasslands Terminal is expected to be in-service by the second quarter of 2019.
- *Cheyenne Connector.* We are currently constructing the Cheyenne Connector, a new pipeline lateral in Northeast Colorado that will transport natural gas from the DJ Basin in Weld County to the Rockies Express Pipeline's Cheyenne Hub, discussed below. Cheyenne Connector will be a large-diameter pipeline approximately 70 miles long, with an initial capacity of at least 600 mmcf/d and significant capability for expansion. Cheyenne Connector is expected to be in-service in the fourth quarter of 2019.
- *Cheyenne Hub.* The Rockies Express Pipeline's Cheyenne Hub is an existing natural gas facility owned and operated by Rockies Express Pipeline in northern Weld County. At the Cheyenne Hub, the existing Rockies Express Pipeline intersects and/or connects with numerous other natural gas pipelines. The Cheyenne Hub Enhancement Project consists of modifications to the Rockies Express Pipeline's Cheyenne Hub to accommodate firm receipt and delivery interconnectivity among multiple natural gas pipelines with various operating pressures and will provide customers significant diversity in terms of market access. Cheyenne Hub is expected to be in-service by the fourth quarter of 2019.
- *Plaquemines Liquids Terminal.* In November 2018, we entered into a joint venture agreement with Drexel Hamilton Infrastructure Fund I, L.P. ("DHIF") to jointly-own Plaquemines Liquids Terminal, LLC ("PLT"). We made an initial cash contribution of $30.7 million in exchange for a 100% preferred membership interest and a 80% common membership interest. DHIF contributed any and all assets and rights related to the project in exchange for a 20% common membership interest and the right to receive certain special distributions. PLT will construct a liquid export terminal facility on the Mississippi River on an approximately 600-acre site in Plaquemines Parish, Louisiana. The site was acquired in November 2018 pursuant to an agreement between PLT and the Plaquemines Port & Harbor Terminal District. The facility is expected to offer up to 20 million barrels of storage for both crude oil and refined products and export facilities capable of loading Suezmax and Very Large Crude Carriers ("VLCC") vessels for international delivery. The project is currently expected to be in-service in 2020.

Competition

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

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, recycling 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 Enbridge Inc., Kinder Morgan Inc., Northern Natural Gas Company, Southern Star Central Gas Pipeline, Inc., Energy Transfer LP, and The Williams Companies Inc., 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 Oil Corporation, Plains All American Pipeline, L.P., Suncor Energy Inc., SemGroup Corporation, Magellan Midstream Partners, L.P., Anadarko Petroleum Corporation, NGL Energy Partners LP, Energy Transfer LP, and Enbridge Inc. 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.

We also experience competition in the natural gas processing business. Our principal competitors for processing business include other facilities that service its 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., ONEOK, Inc., Western Gas Partners, LP, The Williams Companies Inc., 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. In addition, Terminals encounters competition in the crude oil storage and terminalling business from facilities owned by Magellan Midstream Partners, L.P., NGL Energy Partners LP, Plains All American, L.P., Blueknight Energy Partners, L.P., SemGroup Corporation, and Enbridge Inc. Further, we experience competition in the water business services. Our principal competitors in such business are other midstream companies, such as NGL Energy Partners LP, 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, PRE Pipeline, and Iron Horse Pipeline 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 and PRE Pipeline 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, the 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.

Notice of Inquiry on FERC's Pipeline Certificate Policy Statement, PL18-1-000

On April 19, 2018, the FERC issued a Notice of Inquiry regarding whether it should revise its current policy statement on its review and authorization of natural gas pipelines under Section 7 of the Natural Gas Act. The current policy statement, "Certification of New Interstate Natural Gas Pipeline Facilities - Statement of Policy," was issued in 1999. The Notice of Inquiry requested comments in four general areas: (1) the reliance on precedent agreements to demonstrate need for a proposed project; (2) the potential exercise of eminent domain and landowner interests; (3) the FERC's evaluation of alternatives and environmental effects under the National Environmental Policy Act and the Natural Gas Act; and (4) the efficiency and effectiveness of the FERC's certificate processes. Comments have been filed by interested parties and the proceeding is pending before the FERC.

Examples of Our Dockets at the FERC

Trailblazer 2018 General Rate Case Filing

On June 29, 2018, Trailblazer filed a general rate case with the FERC proposing, among other things, an increase in rates on Trailblazer's Existing System Firm Transportation Service and a decrease in rates for Expansion System Firm Transportation Service and interruptible services. On July 31, 2018, the FERC issued an Order: (1) approving the as-filed rate decreases for Expansion System Firm Transportation Service and interruptible services, effective August 1, 2018; (2) accepting and suspending the rest of the rate case filing (including the proposed rate increases) to become effective January 1, 2019 subject to refund, and establishing hearing and settlement procedures; and (3) establishing a paper hearing to examine the extent to which Trailblazer is entitled to an Income Tax Allowance. Parties have submitted briefs on the Income Tax Allowance issue and the paper hearing remains pending before the FERC. The remaining issues are currently subject to settlement judge procedures.

Cheyenne Hub Enhancement Project

On March 2, 2018, Rockies Express submitted an application pursuant to section 7(c) of the NGA for a certificate of public convenience and necessity authorizing the construction and operation of certain booster compressor units and ancillary facilities located at the Cheyenne Hub in Weld County, Colorado that will enable Rockies Express to provide a new hub service allowing for firm receipts and deliveries between Rockies Express and certain other interconnected pipelines at the Cheyenne Hub. Rockies Express filed this certificate application in conjunction with a concurrently filed certificate application by Cheyenne Connector, LLC ("Cheyenne Connector") for the Cheyenne Connector Pipeline Project further described below. The comment period for the Cheyenne Hub Enhancement Project closed on April 9, 2018. To date, various comments have been filed by market participants and others regarding the proposed project. Rockies Express has also responded to data requests from the FERC's relevant program offices. On October 11, 2018, the FERC issued a Notice of Schedule of Environmental Review setting December 18, 2018 as the date of issuance of the Environmental Assessment and March 18, 2019 as the deadline for decisions by other federal agencies on requests for authorizations for the proposed project. On December 18, 2018, the FERC issued the Environmental Assessment.

Cheyenne Connector Pipeline Project

On March 2, 2018, Cheyenne Connector, an indirect subsidiary of TGE, submitted an application pursuant to section 7(c) of the NGA for a certificate of public convenience and necessity to construct and operate a 70-mile, 36-inch pipeline to transport natural gas from multiple gas processing plants in Weld County, Colorado to Rockies Express' Cheyenne Hub. The comment period for the Cheyenne Connector Pipeline Project closed on April 9, 2018. To date, various comments have been filed by market participants and others regarding the proposed project. Cheyenne Connector has also responded to data requests from the FERC's relevant program offices. On October 11, 2018, the FERC issued a Notice of Schedule of Environmental Review setting December 18, 2018 as the date of issuance of the Environmental Assessment and March 18, 2019 as the deadline for decisions by other federal agencies on requests for authorizations for the proposed project. On December 18, 2018, the FERC issued the Environmental Assessment.

For additional information regarding these dockets and certain other regulatory filings with the FERC, see Note 18 – *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. 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. On January 13, 2017, PHMSA finalized new hazardous liquid pipeline safety regulations. Among other things, the final rule would have required additional event-driven and periodic inspections, required the use of leak detection systems on all hazardous liquid pipelines, modified repair criteria, and required certain pipelines to eventually accommodate in-line inspection tools. However, on January 24, 2017, this rule was withdrawn for further review by the Trump Administration and 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. In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline. We will continue pipeline integrity testing programs to assess and maintain the integrity of its 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 its 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 continued performing remediation to increase and maximize its operating capacity over the long-term and spent approximately $21 million during 2018 for this pipe replacement and remediation work. As of October 2018, the pipeline was returned to its maximum allowable operating capacity. 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 TEP's 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, 2016 and 2017, Pony Express completed approximately $18 million of remediation for anomalies identified on the Pony Express System associated with portions of the pipeline that were converted from natural gas to crude oil service. Remediation work was substantially complete as of March 1, 2018.

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 it 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. In October 2018, the EPA proposed a rule to reconsider and amend various requirements of the NSPS standard. However, the NSPS rule currently remains in effect. The EPA also finalized a rule effective August 2, 2016 regarding the alternative criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes. EPA draft guidance issued in September 2018 clarified that this rule pertains to the oil and gas industry. 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. This rule was suspended, stayed, and reinstated before the BLM issued a final rule in September 2018 that rescinds and revises many of the requirements of the 2017 rule. The revision rule is being challenged in the U.S. District Court for the Northern District of California but currently remains in effect.

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 presents 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 it 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. Many interested parties believe that the rule expands federal jurisdiction under the CWA. This rule was initially challenged in federal courts at both the appellate and district court levels. It was stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit but, based on a January 2018 U.S. Supreme Court decision determining that only the district courts have jurisdiction to hear the challenges, the Sixth Circuit stay was withdrawn. Some federal district courts have enjoined the rule, but the rule is currently effective in over 20 states. In February 2018, the agencies also published a final rule adding a February 6, 2020 applicability date to the 2015 rule, but this rule was enjoined nationwide in August 2018. In December 2018, the EPA and the U.S. Army Corp of Engineers released a proposed rule to redefine the extent of CWA jurisdiction. If finalized, this rule would replace the 2015 rule defining "waters of the United States" and the scope of federal jurisdiction.

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 that 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, surface use agreements, and licenses.

Insurance

We generally share insurance coverage with Tallgrass Energy Holdings pursuant to the terms of the TGE Omnibus Agreement and an Omnibus Agreement dated May 17, 2013 entered into among TEP, TEP GP, Tallgrass Development and the general partner of Tallgrass Development (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 are managed and operated by the board of directors and executive officers of our general partner. As of December 31, 2018, we employed approximately 750 full-time employees through Tallgrass Management, LLC ("Tallgrass Management"). Prior to July 1, 2018, Tallgrass Management was a wholly-owned subsidiary of Tallgrass Energy Holdings. Effective July 1, 2018, Tallgrass Management was contributed to Tallgrass Equity in connection with the TEP Merger. As a result, the costs of employer and director compensation and benefits are now incurred directly by Tallgrass Equity.

Under the terms of the TGE Omnibus Agreement, 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. 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 cash dividends on our Class A shares at the current dividend level, or pay any dividend at all, and the trading price of our Class A shares 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 cash dividend at the current dividend level, or at all, to holders of our Class A shares.

We may not have sufficient available cash each quarter to enable us to pay the quarterly cash dividend at the current dividend level or at all. The amount of cash we have available for dividends on our Class A shares 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 source, 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 dividend 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 quarterly cash dividends to our Class A shareholders 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, 2018, approximately 92% of our natural gas transportation and storage revenues were generated under firm fee transportation and storage contracts and approximately 87% of our crude oil transportation revenues were generated under firm fee transportation contracts. As of December 31, 2018, the weighted average remaining life of our long-term natural gas transportation contracts and natural gas storage contracts at TIGT and Trailblazer was approximately five years and four years, respectively, and the weighted average remaining life of our crude oil transportation contracts at Pony Express was approximately two years. 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 2018 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 quarterly cash dividends to our Class A shareholders 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 quarterly cash dividends to our Class A shareholders. 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 quarterly cash dividends to our Class A shareholders.

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 and in the second half of 2018, 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, 2018, Continental Resources accounted for approximately 10% of our revenues on a consolidated basis. In addition, for the year ended December 31, 2018, approximately 47% of our consolidated revenues were represented by the top ten customers on our Pony Express System. We own a 75% membership interest in Rockies Express, which is not consolidated for financial reporting purposes. Approximately 18%, 13%, and 12%, respectively, of Rockies Express' total revenues for the year ended December 31, 2018 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 quarterly cash dividends to our Class A shareholders 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 quarterly cash dividends to our Class A shareholders, the price of our Class A shares, 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 share basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per share 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 dividends to our Class A shareholders. 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 maintain or increase dividends 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 share basis. For example, we completed a number of acquisitions in 2018, including the acquisition of an additional 25.01% membership interest in Rockies Express from Tallgrass Development, a 100% membership interest in NGL Water Solutions Bakken, LLC from NGL Energy Partners, a 51% membership interest in Pawnee Terminal from Zenith Energy, and a 38% membership interest in Deeprock North from Kinder Morgan. 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 its 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 cash available for dividend per share, it could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash dividends to our Class A shareholders.

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, which for many of our projects includes a requirement to obtain a certificate from the FERC authorizing the project before construction can commence;
- 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, we incurred construction expenditures in 2018 for the construction of the Iron Horse Pipeline 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.

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 dividends 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 dividends. We could be required to use cash from our operations or incur borrowings or sell additional Class A shares or other limited partner interests in order to fund our expansion capital expenditures. Using cash from operations will reduce cash available for dividends to our Class A shareholders. 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 quarterly cash dividends to our Class A shareholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant dilution of Class A shareholders and increase the aggregate amount of cash required to maintain the then-current dividend rate, which could materially decrease our ability to pay quarterly cash dividends at the then-current dividend 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, 2018, Pony Express had a cumulative net deficiency balance of $97.1 million and a cumulative shipper incremental balance of $4.9 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 and could have a material adverse effect on our ability to make quarterly cash dividends to our Class A shareholders.

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 maintain or increase dividends to our Class A shareholders. 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 quarterly cash dividends to our Class A shareholders.

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.

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, 2018, approximately 53% 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 dividends to our Class A shareholders.

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 dividends to our Class A shareholders.

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 93% of the Pony Express System's current available contractible 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 quarterly cash dividends to our Class A shareholders.

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 Rockies Express' ability to make distributions to its equity holders and our ability to make quarterly cash dividends to our Class A shareholders.

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 quarterly cash dividends to our Class A shareholders 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 dividends to our Class A shareholders could be adversely affected.

The lack of diversification of our assets and geographic locations could adversely affect our ability to make quarterly cash dividends to our Class A shareholders.

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 dividends to our Class A shareholders 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. In addition, a number of our other assets are also located in Colorado. Certain interest groups in Colorado generally opposed to the development of oil, natural gas and NGLs, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives aimed at significantly limiting or preventing the development of oil, natural gas and NGLs. For example, a Colorado ballot initiative, Proposition 112, would have substantially increased setback distances for various upstream activities, thereby substantially restricting new oil and gas development in the state. Although Proposition 112 was defeated in the November 2018 elections, similar efforts in Colorado, if passed, could restrict oil and gas development in the future which could result in a reduction in demand for our services.

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 the TEP 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 dividend to Class A shareholders depends primarily on our cash flow rather than on our profitability, which may prevent us from making dividends, even during periods in which we record net income.

The amount of cash we have available for dividends 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 dividends during periods when we record losses for financial accounting purposes and may not make cash dividends 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, 2018, approximately 12%, 51%, and 37% 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 quarterly cash dividends to our Class A shareholders 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 rather than alternative energy sources. 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. For example, from the second half of 2014 through the first half of 2016, the oil and gas industry 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. Persistent low commodity prices could result in 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. Although producers in areas we serve increased their production in 2018 and are expected to continue this increase in 2019, it may take a prolonged period before the increased production 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 dividends to our Class A shareholders.

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 and PRE Pipeline are subject to regulation by the FERC under the ICA, and the Energy Policy Act of 1992. We provide interstate crude oil transportation service on the Pony Express System and PRE Pipeline 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.

On June 29, 2018, Trailblazer filed a general rate case with the FERC proposing, among other things, an increase in rates on Trailblazer's Existing System Firm Transportation Service and a decrease in rates for Expansion System Firm Transportation Service and interruptible services. On July 31, 2018, the FERC issued an Order: (1) approving the as-filed rate decreases for Expansion System Firm Transportation Service and interruptible services, effective August 1, 2018; (2) accepting and suspending the rest of the rate case filing (including the proposed rate increases) to become effective January 1, 2019 subject to refund, and establishing hearing and settlement procedures; and (3) establishing a paper hearing to examine the extent to which Trailblazer is entitled to an Income Tax Allowance. Resolution of these issues remains pending before the FERC. In the event that Trailblazer is not able to recover its full cost of service as a result of the outcome of this proceeding, Trailblazer's cash flows and its results of operations could be adversely affected.

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 and the PRE Pipeline, parties having standing and not restricted by contract may protest newly filed rates and terms and conditions of service within a prescribed notice period. Currently, shippers party to a TDA for the Pony Express System are generally limited from protesting certain rates on the Pony Express System, but this limitation will not apply to such shipper upon expiration of their TDA. 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 or the PRE Pipeline 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 the 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 dividends to our Class A shareholders.

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. The FERC generally does not regulate crude oil transportation contracts, but contract rates must be filed with the FERC and tariff rules and regulations generally apply to contract shippers.

On our interstate crude oil pipeline systems, the Pony Express System and the PRE Pipeline, shippers may generally challenge new or existing rates at any time unless they have contractually agreed not to. Currently, shippers party to a TDA for the Pony Express System are generally limited from protesting certain rates on the Pony Express System, but this limitation will not apply to such shipper upon expiration of their TDA. As a result of settlement or by order of the FERC following hearing, its 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.

The FERC has historically permitted regulated interstate crude oil and natural gas pipelines to include an income tax allowance in their cost of service used to calculate cost-based transportation rates. The allowance is intended to reflect the actual or potential tax liability attributable to the regulated entity's operating income, regardless of the form of ownership. On July 1, 2016, in *United Airlines, Inc. v FERC*, the United States Court of Appeals for the D.C. Circuit vacated a pair of FERC orders to the extent they permitted an interstate refined petroleum products pipeline owned by a Master Limited Partnership ("MLP") to include an income tax allowance in its cost-of-service rates. The D.C. Circuit held that the FERC had failed to demonstrate that the inclusion of both an income tax allowance in the pipeline's rates and a return on equity determined using a discounted cash flow methodology would not lead to a double-recovery of income tax costs for pipelines organized as an MLP.

Following the D.C. Circuit's decision, the FERC issued its Revised Policy Statement on Treatment of Income Taxes in Docket No. PL17-1-000 on March 15, 2018 which eliminates the recovery of an income tax allowance by MLP crude oil and natural gas pipelines in cost-of-service-based rates. The FERC directed MLP crude oil pipelines to reflect the elimination of the income tax allowance in their Form No. 6, page 700 reporting and stated that it will incorporate the effects of this Revised Policy on industry-wide crude oil pipeline costs in the 2020 five-year review of the crude oil pipeline index level. The Commission also stated that it would address income tax allowances for other "pass-through" entities that are not MLPs in future proceedings.

While we are not an MLP, our ownership of our FERC regulated pipelines is held through our ownership in Tallgrass Equity which is a "pass-through" entity. The FERC could determine to apply the elimination of the income tax allowance to "pass-through" entities like Tallgrass Equity. To the extent that we charge cost-of-service based rates, those rates could be affected by the elimination of the income tax allowance if our rates are subject to complaint or challenge raised by shippers or by the FERC acting on its own initiative, or if we propose new cost-of-service rates or changes to our existing rates. In such instances, it is possible that certain tariff rates could be reduced, which could adversely affect our financial position, results of operations and ability to make quarterly cash dividends to our Class A shareholders.

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. In late 2018, Rockies Express and TIGT each submitted one-time informational filings in compliance with Order No. 849, which required interstate natural gas pipelines to make a one-time informational filing on the rate effect of the changes in tax laws and policy following the Tax Cuts and Jobs Act and the FERC's changes to its Income Tax Policy Statement following the decision of the U.S. Court of Appeals for the D.C. Circuit in United Airlines, Inc. v. FERC in 2016. The FERC has indicated that it will review these filings to determine whether a pipeline's rates should be set for investigation under Section 5 of the Natural Gas Act or instead no action should be taken on the filing. The filings of Rockies Express and TIGT are pending before the FERC. If the 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 quarterly cash dividends to our Class A shareholders.

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 dividends to our Class A shareholders.

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 quarterly cash dividends to Class A shareholders.

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 until February 27, 2018, when temporary repairs were completed allowing the segment to be placed back into service. Permanent repairs were completed in September 2018 and the total cost of remediation was approximately $6.1 million prior to any insurance recoveries. 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 dividends to our Class A shareholders. 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 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. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. 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. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective and detective measures or to investigate and remediate any vulnerability to cyber incidents.

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.

Violations of data protection laws may carry fines and expose us to criminal sanctions and civil suits.

We are subject to data protection laws. Complying with varying jurisdictional requirements could increase the costs and complexity of compliance, and violations of applicable data protection laws could result in significant penalties. Non-compliance with data protection laws could expose us to regulatory investigations, which could result in fines and penalties. In addition to imposing fines, regulators may also issue orders to stop processing personal data, which could disrupt operations. We could also be subject to litigation from persons or corporations allegedly affected by data protection violations. Any violation of these laws or harm to our reputation could have a material adverse effect on our business, financial condition, results of operations and prospects.

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 19 – *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 November 2018, PHMSA issued a final rule that increased the per-day violation penalty from \$209,002 to \$213,268 and the maximum penalty for a related series of violations from \$2,090,022 to \$2,132,679, effective November 27, 2018. 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 would have required additional event-driven and periodic inspections, required the use of leak detection systems on all hazardous liquid pipelines, modified repair criteria, and required certain pipelines to eventually accommodate in-line inspection tools. However, on January 24, 2017, this rule was withdrawn for further review by the Trump Administration and 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.

The PIPES Act, enacted on June 22, 2016, reauthorized PHMSA's oil and gas pipeline programs through 2019 and provided 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.

In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline.

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 continued performing remediation to increase and maximize its operating capacity over the long-term and spent approximately $21 million during 2018 for this pipe replacement and remediation work. As of October 2018, the pipeline was returned to its maximum allowable operating capacity. 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, 2016 and 2017, Pony Express completed approximately $18 million of remediation for anomalies identified on the Pony Express System associated with portions of the pipeline converted from natural gas to crude oil service. Remediation work was substantially complete as of March 31, 2018.

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 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 $568,000 in 2017, approximately $362,000 in 2018 and we have budgeted approximately $1.1 million for 2019.

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. The EPA has clarified that it will focus on significant public health and environmental problems: exposure to significant releases of volatile organic compounds, reducing non-attainment, and reducing water quality impairment. 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. Many interested parties believe that the rule expands federal jurisdiction under the CWA. This rule was initially challenged in federal courts at both the appellate and district court levels. It was stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit, but based on a January 2018 U.S. Supreme Court decision determining that only the district courts have jurisdiction to hear the challenges, the Sixth Circuit stay was withdrawn. Some federal district courts have enjoined the rule, but the rule is currently effective in over 20 states. In February 2018, the agencies also published a final rule adding a February 6, 2020 applicability date to the 2015 rule, but this rule was enjoined nationwide in August 2018. In December 2018, the EPA and the U.S. Army Corp of Engineers released a proposed rule to redefine the extent of CWA jurisdiction. If finalized, this rule would replace the 2015 rule defining "waters of the United States" and the scope of federal jurisdiction. Although it is unclear how or whether the Corps and the EPA will implement the 2015 rule in states in which we have operations at this time, the rule may require additional Corps or EPA authorizations or involvement in our future operations, for instance, if we extend its pipelines into or across areas (such as certain ditches) newly considered "waters of the United States" under the 2015 final rule.

Certain interest groups generally opposed to the development of oil, natural gas and NGLs, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives aimed at significantly limiting or preventing the development of oil, natural gas and NGLs. For example, a Colorado ballot initiative, Proposition 112, would have substantially increased setback distances for various upstream activities, thereby substantially restricting new oil and gas development in the state. Although Proposition 112 was defeated in the November 2018 elections, similar efforts in Colorado or elsewhere, if passed, could restrict oil and gas development in the future which could result in a reduction in demand for our services.

The general 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. In October 2018, the EPA proposed a rule to reconsider and amend various requirements of the NSPS standard. However, the rule currently remains in effect. In 2016, 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. This rule was suspended, stayed, and reinstated before the BLM issued a final rule in September 2018 that rescinds and revises many of the requirements of the 2017 rule. The revision rule is being challenged in the U.S. District Court for the Northern District of California but currently remains in effect. 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. In October 2018, the EPA proposed a rule to reconsider and amend various requirements of the NSPS standard. 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; however, facilities that were lawfully discharging this wastewater to publicly owned sewage treatment plants on April 17, 2015 have until August 29, 2019 to comply with this rule. 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 rescission is currently subject to legal challenge. Also, the BLM 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. This rule was suspended, stayed, and reinstated before the BLM issued a final rule in September 2018 that rescinds and revises many of the requirements of the 2017 rule. The revision rule is being challenged in the U.S. District Court for the Northern District of California but currently remains in effect.

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. The USGS also produced a one-year 2017 induced seismicity model that forecast an elevated hazard from induced seismicity in Oklahoma compared to the hazard calculated for seismicity before 2009. 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 dividends to our Class A shareholders.

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 quarterly cash dividends to our Class A shareholders.

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 quarterly cash dividends to our Class A shareholders.

The TEP revolving credit facility and the indentures governing the TEP senior notes contain certain restrictions which could adversely affect our business, financial condition, results of operations and ability to make quarterly cash dividends to our Class A shareholders.

We are dependent upon certain earnings and cash flow generated by our operations in order to meet our debt service obligations. The TEP revolving credit facility, the indenture governing its 4.75% senior notes due 2023 (the "2023 Notes") the indenture governing its 5.50% senior notes due 2024 (the "2024 Notes"), and the indenture governing its 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 quarterly cash dividends. For example, the TEP revolving credit facility limits TEP's ability and the ability of its restricted subsidiaries to, among other things:

- incur or guarantee additional indebtedness;
- redeem or repurchase units or pay 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.

The TEP revolving credit facility also contains covenants requiring TEP 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 TEP will meet those ratios and tests. Further, TEP's obligations under the revolving credit facility are (i) guaranteed by TEP and each of its existing and subsequently acquired or organized direct or indirect wholly-owned domestic subsidiaries, subject to its 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 TEP and each guarantor (other than real property interests related to its pipelines).

Similarly, the indenture governing the 2024 Notes 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, 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 its 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 indentures governing the 2023 Notes and the 2028 Notes contain 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 of its properties to, another person.

The provisions of the TEP revolving credit facility and the indentures governing its 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 the TEP revolving credit facility or the indentures governing its 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 its 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 TEP revolving credit facility, would prohibit TEP's ability to make distributions. If the payment of the indebtedness under the TEP revolving credit facility is accelerated and we are unable to repay the indebtedness in full, the lenders could foreclose on the assets pledged by TEP and the guarantors under the TEP revolving credit facility. In that case, these assets may be insufficient to repay such indebtedness in full, and our Class A shareholders could experience a partial or total loss of their investment.

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 dividends to Class A shareholders 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 dividends, 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 an investment in us. 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 Class A share price, our ability to issue equity or incur indebtedness for acquisitions or other purposes and our ability to make quarterly cash dividends at our intended levels.

The interest rate on borrowings under the TEP 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 the TEP revolving credit facility.

As with other yield-oriented securities, our Class A share price may be impacted by the level of our cash dividend and implied dividend yield. The dividend 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 Class A shares, and a rising interest rate environment could have an adverse impact on our Class A share price, our ability to issue equity or incur indebtedness for acquisitions or other purposes and our ability to maintain or increase quarterly cash dividends on our Class A shares.

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 January 31, 2019, Rockies Express had $1.5 billion of senior notes outstanding, of which $750 million will mature on April 15, 2020, $250 million will mature in 2038 and $500 million will mature in 2040. In addition, Rockies Express has $525 million of outstanding indebtedness pursuant to a term loan facility that provides for a one-time principal payment due on the January 7, 2020 maturity date. Further, Rockies Express has a revolving credit facility with $150 million of borrowing capacity that matures on January 31, 2020.

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 agreements governing its term loan credit facility and revolving credit facility permit 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 2018 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 dividends to our Class A shareholders.

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

Rockies Express' term loan credit facility and revolving credit facility contain 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 term loan credit facility and the revolving credit facility generally require Rockies Express to comply with various affirmative and negative covenants, including a limit on the leverage ratio (as defined in each 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 quarterly cash dividends to our Class A shareholders. 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 and in some states it may not be available at all. 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, recycling 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 accurately report our financial results or prevent fraud. As a result, shareholders could lose confidence in our financial reporting, which would harm our business and the trading price of our Class A shares.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a publicly traded partnership. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results will be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our Class A shares.

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 its water business services, may have a material adverse effect on our business, financial condition and results of operations.

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

We do not control Rockies Express through our 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 the decisions of the Rockies Express members effectively require unanimous approval of us and the other member of Rockies Express, Phillips 66. Thus, our investment in Rockies Express involves risks that are not present when we 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.

As an unaffiliated third-party member of Rockies Express, Phillips 66 may have economic or other business interests or goals that are inconsistent with our business interests or goals. The Rockies Express limited liability company agreement expressly permits Rockies Express members 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 quarterly cash dividends to our Class A shareholders are not cumulative.

Our quarterly cash dividends to our Class A shareholders are not cumulative. Consequently, if cash dividends on our Class A shares are not paid with respect to any fiscal quarter then our Class A shareholders will not be entitled to receive that quarter's payments in the future.

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

Our partnership agreement requires us to distribute our available cash to our Class A shareholders on a quarterly basis. 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 dividend 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 shares in connection with any acquisitions or expansion capital expenditures, the payment of dividends on those additional shares may increase the risk that we will be unable to maintain or increase our per share dividend level. There are no limitations in our partnership agreement on our ability to issue additional shares, including shares ranking senior to the Class A shares. 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 cash available for dividends to our Class A shareholders.

If we issue additional Class A shares without canceling an equivalent number of Class B shares, Tallgrass Equity incurs additional debt, we incur debt or we or Tallgrass Equity are required to pay taxes, the payment of distributions on those additional Class A shares or interest on that debt or payment of such taxes could increase the risk that we will be unable to maintain or increase our cash dividend levels.

Restrictions in TEP's and Rockies Express' respective credit facilities and the indentures governing TEP's and Rockies Express' existing senior notes could limit Tallgrass Equity's ability to make distributions to us, thereby limiting our ability to make quarterly cash dividends to our Class A shareholders. Any credit facility we enter into in the future could pose similar restrictions that would further limit our ability to make quarterly cash dividends.

TEP's and Rockies Express' respective credit facilities and the indentures governing TEP's and Rockies Express' existing senior notes contain various operating and financial restrictions and covenants. Tallgrass Equity's, TEP's and Rockies Express' respective ability to comply with these restrictions and covenants may be affected by events beyond their control, including prevailing economic, financial and industry conditions. If TEP or Rockies Express are unable to comply with these restrictions and covenants, any indebtedness under these credit facilities and indentures may become immediately due and payable and TEP's and Rockies Express' respective lenders' commitment to make further loans under their revolving credit facilities may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments.

We may enter into a credit facility in the future that would impose similar restrictions to those discussed above. In addition, our payment of principal and interest on any future indebtedness would reduce our cash available for dividends to our Class A shares.

For more information regarding the TEP revolving credit facility and the indentures governing TEP's existing senior notes, please see the section above "*—The TEP revolving credit facility and the indentures governing the TEP senior notes contain certain restrictions which could adversely affect our business, financial condition, results of operations and ability to make quarterly cash dividends to our Class A shareholders."* For more information regarding Rockies Express' revolving credit facility and the indentures governing Rockies Express' existing senior notes, please see the sections above *"—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." and "—Rockies Express' term loan credit facility and revolving credit facility contain certain restrictions which could limit its financial flexibility and increase its financing costs."*

Our shareholders do not vote in the election of our general partner's directors. The Exchange Right Holders own a sufficient number of shares to allow them to prevent the removal of our general partner.

Our shareholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. The board of directors of our general partner, including our independent directors, is currently designated and elected by Tallgrass Energy Holdings or its designees. Our shareholders do not have the ability to elect our general partner or the members of the board of directors of our general partner.

In addition, if our Class A shareholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. Our general partner may not be removed except by vote of the holders of at least 80% of our outstanding shares, voting together as a single class. The Exchange Right Holders own all of our Class B shares, which collectively represents 44.21% of our total outstanding Class A and Class B shares. This ownership level enables the Exchange Right Holders to prevent our general partner's removal.

As a result of these provisions, the price at which our shares trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Our general partner may cause us to issue additional Class A shares or other equity securities, including equity securities that are senior to our Class A shares, without your approval, which may adversely affect you.

Our general partner may cause us to issue an unlimited number of additional Class A shares, or other equity securities of equal rank with the Class A shares, without shareholder approval. In addition, we may issue an unlimited number of shares that are senior to our Class A shares in right of dividend, liquidation and voting. Except for Class A shares issued in connection with the exercise by any Exchange Right Holder of its right to exchange a Class B share for a Class A share (the "Exchange Right"), each of which will result in the cancellation of an equivalent number of Class B shares and therefore have no effect on the total number of outstanding shares, the issuance of additional Class A shares, or other equity securities of equal or senior rank, may have the following effects:

- each shareholder's proportionate ownership interest in us may decrease;
- the amount of cash available for dividends on each Class A share may decrease;
- the relative voting strength of each previously outstanding Class A share may be diminished;
- the date upon which we begin paying material U.S. federal income taxes, or upon which a material portion of our dividends constitute taxable dividend income for U.S. federal income tax purposes, could be accelerated; and
- the market price of the Class A shares may decline.

You may not have limited liability if a court finds that shareholder action constitutes control of our business.

Under Delaware law, you could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our shareholders (who hold limited partner interests despite the fact that we use the term "shareholder" in this Annual Report) as a group to remove or replace our general partner, to approve some amendments to the partnership agreement or to take other action under our partnership agreement constituted participation in the "control" of our business. Additionally, the limitations on the liability of holders of limited partner interests for the liabilities of a limited partnership have not been clearly established in many jurisdictions.

Furthermore, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a shareholder may be liable to us for the amount of a dividend for a period of three years from the date of the dividend.

Our partnership agreement restricts the rights of shareholders owning 20% or more of our shares.

Our shareholders' voting rights are restricted by the provision in our partnership agreement generally providing that any shares held by a person or group that owns 20% or more of any class of shares then outstanding, other than our general partner, the Exchange Right Holders or their respective affiliates and persons who acquired such shares with the prior approval of our general partner's board of directors, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of our shareholders to call meetings or to acquire information about our operations, as well as other provisions limiting our shareholders' ability to influence the manner or direction of our management. As a result, the price at which our Class A shares trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Future sales of our Class A shares in the public market, including sales of Class A shares by the Exchange Right Holders after the exercise of the Exchange Right, could reduce our Class A share price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

Subject to certain limitations and exceptions, the Exchange Right Holders may cause the exchange of their Tallgrass Equity units (together with a corresponding number of Class B shares) for Class A shares (on a one-for-one basis, subject to customary conversion rate adjustments for equity splits and reclassification and other similar transactions) and then sell those Class A shares. For example, in November 2016 certain participating Exchange Right Holders sold 10,350,000 Class A Shares in a secondary offering. Further, in accordance with a shareholder and registration rights agreement entered into with the Exchange Right Holders, we have registered the resale of 125,291,659 Class A shares issuable upon exercise of the Exchange Right pursuant to our Form S-3 (File No. 333-225382) filed with the SEC on June 1, 2018, which became effective June 13, 2018.

We may also issue additional Class A shares or convertible securities in subsequent public or private offerings. We cannot predict the size of future issuances of our Class A shares or securities convertible into Class A shares or the effect, if any, that future issuances and sales of our Class A shares, including sales of Class A shares by the Exchange Right Holders after the exercise of the Exchange Right, will have on the market price of our Class A shares. Sales of substantial amounts of our Class A shares (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our Class A shares.

Tallgrass Energy Holdings currently has sole authority to elect the board of directors of our general partner, and following consummation of the Blackstone Acquisition, BIP will have such authority.

Tallgrass Energy Holdings currently has the ability to elect all of the members of our board of directors. In addition, Tallgrass Energy Holdings is able to determine the outcome of nearly all matters requiring shareholder approval, including certain mergers and other material transactions, and is able to cause or prevent a change in the composition of our board of directors or a change in control of our company that could deprive our shareholders of an opportunity to receive a premium for their Class A shares as part of a sale of our company. Certain of the Exchange Right Holders currently own 100% of the voting interests in Tallgrass Energy Holdings and EMG, Kelso and Tallgrass KC each have the right to designate two members to the six-person board of managers of Tallgrass Energy Holdings for so long as they maintain certain ownership percentages in

Tallgrass Energy Holdings. Following consummation of the Blackstone Acquisition, BIP will own 100% of the membership interests in our general partner and will have the ability to elect all of the members of the board of directors of our general partner, subject to certain contractual rights to designate directors, including those granted to our chief executive officer, Mr. Dehaemers, to (i) designate one individual from the three specified executive officers to serve as a member of the board of directors of our general partner until December 31, 2020, for so long as Mr. Dehaemers remains a member of the board of directors of our general partner, and (ii) under certain circumstances, designate one individual to serve as an independent member of the board of directors of our general partner, for so long as Mr. Dehaemers is employed as the chief executive officer of our general partner. Prior to the Blackstone Acquisition, Tallgrass Energy Holdings continues to be able to, and following consummation of the Blackstone Acquisition, BIP will be able to, strongly influence all matters requiring shareholder approval, regardless of whether or not shareholders believe that the transaction is in their own best interests.

A valuation allowance on our deferred tax asset could reduce our earnings.

A significant deferred tax asset was recorded as a result of certain reorganization transactions completed in connection with the TGE IPO. In November 2016, we completed a Secondary Offering of Class A shares, which resulted in the recognition of an additional deferred tax asset. The aggregate deferred tax asset was $273.5 million as of December 31, 2018. GAAP requires that a valuation allowance must be established for deferred tax assets when it is more likely than not that they will not be realized. If we were to determine that a valuation allowance was appropriate for our deferred tax asset, we would be required to take an immediate charge to earnings with a corresponding reduction of partners' equity and increase in balance sheet leverage as measured by debt to total capitalization.

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

Because we are a limited partnership, the NYSE does not require our general partner to have a majority of independent directors on its board of directors. The NYSE also does not require our general partner to establish a compensation committee or a nominating and corporate governance committee. Accordingly, our shareholders do not have the same protections afforded to certain corporations that are subject to all the NYSE corporate governance requirements. In addition, as a limited partnership, we are not required to seek shareholder approval for issuances of Class A shares including issuances in excess of 20% of outstanding equity securities, or for issuances of equity to certain affiliates.

We may incur liability as a result of our ownership of TEP's general partner.

Under Delaware law, a general partner of a limited partnership is generally liable for the debts and liabilities of the partnership for which it serves as general partner, subject to the terms of any indemnification agreements contained in the partnership agreement and except to the extent the partnership's contracts are non-recourse to the general partner. As a result of our structure, we indirectly own and control the general partner of TEP. To the extent the indemnification provisions in TEP's partnership agreement or non-recourse provisions in our contracts are not sufficient to protect TEP GP from such liability, we may in the future incur liabilities as a result of our indirect ownership of TEP's general partner. Please read the section entitled *"—Risks Related to Conflicts of Interest."*

Risks Related to Conflicts of Interest

Our existing organizational structure and the relationships among us, our general partner, Tallgrass Energy Holdings, the owners of Tallgrass Energy Holdings, including the Exchange Right Holders, and their affiliated entities present the potential for conflicts of interest. Moreover, additional conflicts of interest may arise in the future among us and the entities affiliated with any general partner or similar interests we acquire.

Conflicts of interest may arise as a result of our organizational structure and the relationships among us, our general partner, and its direct and indirect owners, which include Tallgrass Energy Holdings, the owners of Tallgrass Energy Holdings, including the Exchange Right Holders, and their affiliated entities prior to the Blackstone Acquisition, and BIP, GIC SI and their affiliated entities following consummation of the Blackstone Acquisition.

Our partnership agreement defines the duties of our general partner (and, by extension, its officers and directors). Our general partner's board of directors or its conflicts committee has authority on our behalf to resolve any conflict involving us and they have broad latitude to consider the interests of all parties to the conflict.

Conflicts of interest may arise between us and our shareholders, on the one hand, and our general partner and its direct and indirect owners, on the other hand, which include Tallgrass Energy Holdings and the Exchange Right Holders, and affiliated entities prior to the Blackstone Acquisition, and BIP, GIC SI and their affiliated entities following consummation of the Blackstone Acquisition. The resolution of these conflicts may not always be in our best interest or that of our shareholders.

Certain of the Exchange Right Holders own 100% of the voting interests in Tallgrass Energy Holdings and the Exchange Right Holders control all of our Class B shares, which represents approximately 44.21% of the combined voting power of our Class A and Class B shares.

As of February 8, 2019, certain of the Exchange Right Holders own 100% of the voting interests in Tallgrass Energy Holdings and the Exchange Right Holders hold Class B shares representing approximately 44.21% of the combined voting power of our Class A and Class B shares. Although each of the Exchange Right Holders are entitled to act separately in their own respective interests with respect to their ownership interest in Tallgrass Energy Holdings and us, certain of the Exchange Right Holders collectively have the ability to elect all the members of Tallgrass Energy Holdings' board of managers, each of whom also serves as a member of the board of directors of our general partner. So long as any of the Exchange Right Holders continue to own a significant amount of the voting interests in Tallgrass Energy Holdings, they will continue to be able to control our management and affairs. Following consummation of the Blackstone Acquisition, BIP will own 100% of the membership interests in our general partner, and will, subject to certain contractual restrictions, control approximately 44% of the combined voting power of our Class A shares and Class B shares.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our Class A shares 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 shareholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the shareholders 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 shareholders. 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; 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 shareholders.

By purchasing shares, you agree to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our Class A shares 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 shareholders 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 shareholders 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 shareholders) 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 voting shares, excluding any shares 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 shareholders 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.

Our general partner's affiliates and Tallgrass Energy Holdings may compete with us.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. The restrictions contained in our general partner's limited liability company agreement are subject to a number of exceptions. For example, affiliates of our general partner, including Tallgrass Energy Holdings, the Exchange Right Holders, and their respective affiliates, including Kelso and EMG, are not prohibited from engaging in other businesses or activities that might be in direct competition with us.

Our general partner has a call right that may require you to sell your Class A shares at an undesirable time or price.

If at any time more than 80% of our outstanding shares (including Class A shares issuable upon the exchange of Class B shares) are owned by our general partner, Tallgrass Energy Holdings or their respective affiliates, our general partner has the right (which it may assign to any of its affiliates, Tallgrass Energy Holdings or us), but not the obligation, to acquire all, but not less than all, of the remaining Class A shares held by public shareholders at a price equal to the greater of (x) the highest cash price paid by our general partner, Tallgrass Energy Holdings, or their respective affiliates for any shares purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those shares and (y) the current market price calculated in accordance with our partnership agreement as of the date three business days before the date the notice is mailed. As a result, you may be required to sell your Class A shares at an undesirable time or price and may not receive any return of or on your investment. You may also incur a tax liability upon a sale of your Class A shares.

Tax Risks

The tax treatment of TEP depends on it not being subject to a material amount of entity-level taxation by individual states. If TEP becomes subject to material additional amounts of entity-level taxation for state tax purposes, it would reduce the amount of cash available for dividends to us and increase the portion of our dividends treated as taxable dividends.

We own a 55.79% membership interest in Tallgrass Equity, which directly and indirectly owns all of the partnership interests in TEP. Accordingly, the value of our indirect investment in TEP, as well as the anticipated after-tax economic benefit of an investment in our Class A shares, depends largely on TEP being treated as a partnership for income tax purposes.

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 TEP by any state will reduce the cash available for distributions to TEP unitholders, likely causing a substantial reduction in the value of our Class A shares.

We may incur substantial corporate income tax liabilities on our allocable share of TEP income.

We are classified as a corporation for U.S. federal income tax purposes and, in most states in which TEP does business, for state income tax purposes. To the extent that TEP allocates to us net taxable income in any year, current law provides that we will be subject to U.S. federal income tax at a rate of 21%, and to state income tax at rates that vary from state to state. The amount of cash available for dividends to you will be reduced by the amount of any such income taxes payable by us for which we establish reserves.

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 dividends to our Class A shareholders.

If the IRS makes audit adjustments to TEP's income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from TEP, in which case TEP may require its unitholders and former unitholders to reimburse it for such taxes (including any applicable penalties or interest) or, if TEP is required to bear such payment, TEP's cash available for distribution to TEP's unitholders might be substantially reduced.

If the IRS makes audit adjustments to TEP's income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from TEP. TEP will generally have the ability to shift any such tax liability to its general partner and its unitholders in accordance with their interests in TEP during the year under audit, but there can be no assurance that TEP will be able to (or will choose to) do so under all circumstances. If TEP is required to make payments of taxes, penalties and interest resulting from audit adjustments, it may require its unitholders and former unitholders to reimburse it for such taxes (including any applicable penalties or interest) or, if TEP is required to bear such payment, its cash available for distribution to its unitholders might be substantially reduced.

Taxable gain or loss on the sale of our Class A shares could be more or less than expected.

If a holder sells our Class A shares, the holder will recognize a gain or loss equal to the difference between the amount realized and the holder's tax basis in those Class A shares. To the extent that the amount of our dividends exceeds our current and accumulated earnings and profits, the dividends will be treated as a tax-free return of capital and will reduce a holder's tax basis in the Class A shares. Because our dividends in excess of our earnings and profits decrease a holder's tax basis in Class A shares, such excess dividends will result in a corresponding increase in the amount of gain, or a corresponding decrease in the amount of loss, recognized by the holder upon the sale of the Class A shares.

Our current tax treatment may change, which could affect the value of our Class A shares or reduce our cash available for dividends.

Changes in U.S. federal income tax law relating to our tax treatment as a corporation could result in (i) our being subject to additional taxation at the entity level with the result that we would have less cash available for dividends and (ii) a greater portion of our dividends being treated as taxable dividends. Moreover, we are subject to tax in numerous jurisdictions. Changes in current law in these jurisdictions, particularly relating to the treatment of deductions attributable to acquisitions of interests in Tallgrass Equity, could result in our being subject to additional taxation at the entity level with the result that we would have less cash available for dividends.

Any decrease in our Class A share price could adversely affect our amount of cash available for dividends.

Changes in certain market conditions may cause our Class A share price to decrease. If the Exchange Right Holders exercise their Exchange Right when our Class A share price is less than the price at which the Class A shares were sold in the TGE IPO, the ratio of our income tax deductions to gross income would decline. This decline could result in our being subject to tax sooner than expected, our tax liability being greater than expected, or a greater portion of our dividends being treated as taxable dividends.

The IRS Form 1099-DIV that you receive from your broker may over-report your dividend income with respect to our shares for U.S. federal income tax purposes, and failure to report your dividend income in a manner consistent with the IRS Form 1099-DIV that you receive from your broker may cause the IRS to assert audit adjustments to your U.S. federal income tax return. If you are a non-U.S. holder of our shares, your broker or other withholding agent may overwithhold taxes from dividends paid to you, in which case you generally would have to timely file a U.S. tax return or an appropriate claim for refund in order to claim a refund of the overwithheld taxes.

Dividends we pay with respect to our Class A shares will constitute "dividends" for U.S. federal income tax purposes only to the extent of our current and accumulated earnings and profits. Dividends we pay in excess of our earnings and profits will not be treated as "dividends" for U.S. federal income tax purposes; instead, they will be treated first as a tax-free return of capital to the extent of your tax basis in your shares and then as capital gain realized on the sale or exchange of such shares. We may be unable to timely determine the portion of our dividends that is a "dividend" for U.S. federal income tax purposes.

If you are a U.S. holder of our Class A shares, the IRS Form 1099-DIV may not be consistent with our determination of the amount that constitutes a "dividend" to you for U.S. federal income tax purposes or you may receive a corrected IRS Form 1099-DIV (and you may therefore need to file an amended federal, state or local income tax return). We will attempt to timely notify you of available information to assist you with your income tax reporting (such as posting the correct information on our website). However, the information that we provide to you may be inconsistent with the amounts reported to you by your broker on IRS Form 1099-DIV, and the IRS may disagree with any such information and may make audit adjustments to your tax return.

If you are a non-U.S. holder of our Class A shares, "dividends" for U.S. federal income tax purposes will be subject to withholding of U.S. federal income tax at a 30% rate (or such lower rate as may be specified by an applicable income tax treaty) unless the dividends are effectively connected with your conduct of a U.S. trade or business. In the event that we are unable to timely determine the portion of our dividends that is a "dividend" for U.S. federal income tax purposes, or your broker or withholding agent chooses to withhold taxes from dividends in a manner inconsistent with our determination of the amount that constitutes a "dividend" for such purposes, your broker or other withholding agent may overwithhold taxes from dividends paid to you. In such a case, you generally would have to timely file a U.S. tax return or an appropriate claim for refund in order to obtain a refund of the overwithheld tax.

We expect that our ability to use net operating losses arising prior to the TEP Merger to offset future income will be limited as a result of the TEP Merger, and our ability to use net operating losses arising after the TEP Merger to offset future income may be limited.

We expect that our ability to use any net operating losses ("NOLs") generated by us prior to the TEP Merger to offset future income will be limited due to experiencing an "ownership change" as defined under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), as a result of the TEP Merger. Our ability to use NOLs arising after the TEP Merger to offset future income may be substantially limited if we were to experience another ownership change.

In general, an ownership change occurs if our "5-percent shareholders," as defined under Section 382 of the Code, including certain groups of persons treated as 5-percent shareholders, collectively increased their ownership in Class A shares by more than 50 percentage points over a rolling three-year period. An ownership change can occur as a result of a public offering of Class A shares, as well as through secondary market purchases of Class A shares and certain types of reorganization transactions. As a result of the exchange of TEP common units for Class A shares in the TEP Merger, we expect that the TEP Merger caused us to experience an ownership change.

A corporation (including any entity such as us that is treated as a corporation for U.S. federal income tax purposes) that experiences an ownership change will generally be subject to an annual limitation on the use of its pre-ownership change NOLs (and certain other losses and credits) equal to the equity value of the corporation immediately before the ownership change, multiplied by the long-term tax-exempt rate (as determined by the Internal Revenue Service) for the month in which the ownership change occurs. Such a limitation could, for any given year, have the effect of increasing the amount of our U.S. federal income tax liability, which would negatively impact the amount of after-tax cash available for dividends to holders of Class A shares and our financial condition.

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 March 2020. In addition, we lease our principal executive offices in Leawood, Kansas.

Item 3. Legal Proceedings

See Note 19 – *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

On July 2, 2018, in connection with the TEP Merger, the ticker symbol for our Class A shares listed on the NYSE was changed from "TEGP" to "TGE." Our Class B shares are not listed or traded on any stock exchange.

Holders

As of February 6, 2019, there were 33 shareholders of record of our Class A shares. This number does not include shareholders whose shares are held in trust by other entities. The actual number of beneficial shareholders is greater than the number of holders of record. In addition, as of February 6, 2019, 10 shareholders of record owned all 123,887,893 of our Class B shares.

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 55 days after the end of each quarter, we distribute our available cash to Class A Shareholders of record on the applicable record date.

Definition of Available Cash. Available cash is defined in our partnership agreement and generally means, with respect to any calendar quarter, all cash and cash equivalents on hand at the date of determination of available cash for the distribution in respect of such quarter (including expected distributions from Tallgrass Equity in respect of such quarter), less the amount of cash reserves established by our general partner, which are not subject to a cap, to, among other things:

- comply with applicable law;
- comply with any agreement binding upon us or our subsidiaries (exclusive of TEP and its subsidiaries);
- provide for future capital expenditures, debt service and other credit needs as well as any federal, state, provincial or other income tax that may affect us in the future; or
- otherwise provide for the proper conduct of our business.

Our available cash includes cash on hand resulting from borrowings made after the end of the quarter.

Our Sources of Available Cash. Our sole cash-generating asset is an approximate 55.79% membership interest in Tallgrass Equity. Tallgrass Equity's sole cash generating assets consist of its direct and indirect equity interests in its subsidiaries, including TEP and its 75% membership interest in Rockies Express. Therefore, our cash flow and resulting ability to make distributions will be completely dependent upon the ability of Tallgrass Equity's subsidiaries and Rockies Express to make distributions.

The actual amount of cash that Tallgrass Equity's subsidiaries and Rockies Express, and correspondingly Tallgrass Equity, will have available for distribution will primarily depend on the amount of cash Tallgrass Equity's subsidiaries and Rockies Express generates from their operations. For a description of factors that may impact our results, please read "Item 1A.—Risk Factors."

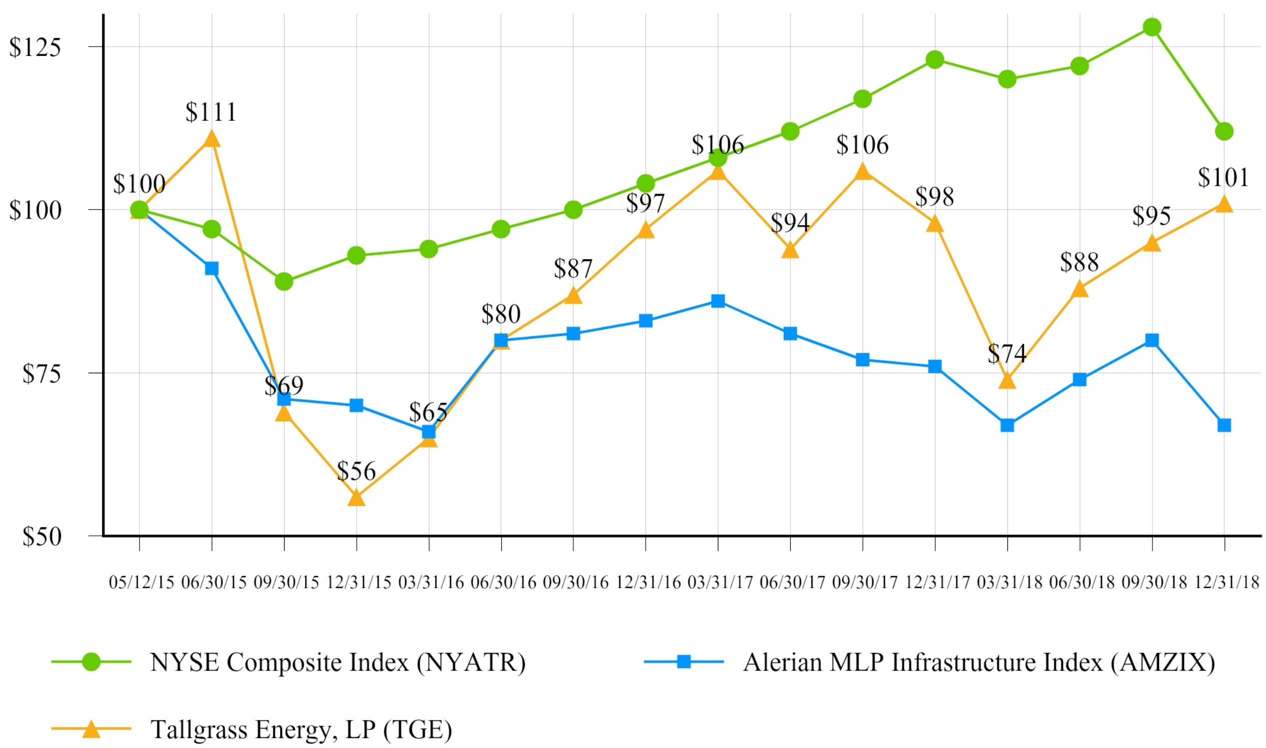
In addition, the actual amount of cash that Tallgrass Equity's subsidiaries, Rockies Express, and Tallgrass Equity will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of revenue Tallgrass Equity's subsidiaries and Rockies Express are able to generate from their respective businesses;
- the level of capital expenditures Tallgrass Equity, Tallgrass Equity's subsidiaries, or Rockies Express makes;
- the level of Tallgrass Equity, Tallgrass Equity's subsidiaries, and Rockies Express' operating, maintenance and general and administrative expenses or related obligations;
- the cost of acquisitions, if any;
- Tallgrass Equity's, Tallgrass Equity's subsidiaries', and Rockies Express' debt service requirements and other liabilities;
- Tallgrass Equity's, Tallgrass Equity's subsidiaries' and Rockies Express' working capital needs;

- restrictions on distributions contained in Tallgrass Equity's, Tallgrass Equity's subsidiaries', or Rockies Express' debt agreements and any future debt agreements;
- Tallgrass Equity's subsidiaries', and Rockies Express' ability to borrow under their respective revolving credit agreements to make distributions; and
- the amount, if any, of cash reserves established by our general partner, in its sole discretion, for the proper conduct of our business.

Performance Graph

The following performance graph compares the performance of our Class A shares with the NYSE Composite Index Total Return and the Alerian MLP Infrastructure Index Total Return during the period beginning on May 12, 2015, and ending on December 31, 2018. The graph assumes a $100 investment in our Class A shares 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, LP or Affiliated Purchasers

None.

Item 6. Selected Financial Data

The historical financial statements included in this Annual Report reflect the consolidated results of operations of TGE's membership interest in Tallgrass Equity and Tallgrass Equity's membership interest in TEP. In connection with the closing of the TGE IPO on May 12, 2015, the following transactions (the "Reorganization Transactions") occurred (i) Tallgrass Equity distributed its interests in Tallgrass Energy Holdings and Tallgrass Energy Holdings distributed its existing limited partner interest in TGE, respectively, to certain of the Exchange Right Holders, that also collectively own 100% of the voting power of Tallgrass Energy Holdings; (ii) TGE issued 47,725,000 Class A shares to the public (including 6,225,000 Class A shares issued in connection with the underwriters' exercise of the overallotment option) for net proceeds of approximately $1.3 billion; (iii) the existing limited partner interests in TGE held by certain of the Exchange Right Holders were converted into 115,729,440 Class B shares, 6,225,000 of which were automatically cancelled in connection with the underwriters' exercise of its overallotment option; (iv) Tallgrass Equity issued 41,500,000 Tallgrass Equity units to TGE in exchange for approximately $1.1 billion in net proceeds from the issuance of TGE's Class A shares to the public and amended the limited liability company agreement of Tallgrass Equity to, among other things, provide that TGE is the managing member of Tallgrass Equity; (v) TGE used the net proceeds from the purchase of the 6,225,000 overallotment option shares to purchase a like amount of Tallgrass Equity units from certain of the Exchange Right Holders; and (vi) Tallgrass Equity entered into a $150 million revolving credit facility and borrowed $150 million thereunder, using the aggregate proceeds from such borrowings, together with the net proceeds from the TGE IPO that Tallgrass Equity received from TGE, to purchase 20 million TEP common units from Tallgrass Development, LP at $47.68 per TEP common unit (the "Acquired TEP Units") and pay offering expenses and other transaction costs. Tallgrass Equity distributed the remaining proceeds (the "Excess Proceeds") to certain of the Exchange Right Holders. The following discussion analyzes the financial condition and results of operations of TGE, which for periods prior to the completion of the TGE IPO on May 12, 2015 includes the financial condition and results of operations of TGE Predecessor, which refers to TGE as recast to show the effects of the Reorganization Transactions.

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," "TGE" and similar terms refer to Tallgrass Energy, LP, together with its consolidated subsidiaries (including Tallgrass Equity, TEP and their respective subsidiaries). The term our "general partner" refers to Tallgrass Energy GP, LLC. References to "Tallgrass Development" or "TD" refer to Tallgrass Development, LP.

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 TGE for the periods and as of the dates indicated. The selected historical financial data for periods prior to the completion of the TGE IPO on May 12, 2015 includes the financial condition and results of operations of TGE Predecessor, which refers to TGE as recast to show the effects of the Reorganization Transactions.

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,									
	2018		2017		2016		2015			2014
Statement of operations data:	(in thousands, except per share amounts)									
Revenue	$	793,259	$	655,898	$	611,662	$	542,661	$	377,313
Operating income	$	350,631	$	271,847	$	258,418	$	206,229	$	58,970
Equity in earnings of unconsolidated investments [1]	$	306,819	$	237,110	$	54,531	$	2,759	$	1,617
Net income before tax	$	523,380	$	432,443	$	267,780	$	193,071	$	65,786
Net income	$	467,671	$	223,985	$	250,039	$	200,348	$	65,786
Net income (loss) attributable to TGE, excluding predecessor operations interest	$	137,127	$	(128,729)	$	26,794	$	24,563 [2]		N/A
Basic net income (loss) per Class A share	$	1.27	$	(2.22)	$	0.55	$	0.51 [2]		N/A
Diluted net income (loss) per Class A share	$	1.27	$	(2.22)	$	0.55	$	0.51 [2]		N/A
Balance sheet data (at end of period):										
Property, plant and equipment, net	$	2,802,429	$	2,394,337	$	2,079,232	$	2,079,567	$	1,853,081
Unconsolidated investments [1]	$	1,861,686	$	909,531	$	475,625	$	13,565	$	15,071
Total assets	$	5,893,509	$	4,292,013	$	3,625,480	$	3,088,635	$	2,476,599
Long-term debt, net	$	3,205,958	$	2,292,993	$	1,555,981	$	901,000	$	559,000
Other:										
Dividends declared per Class A share	$	2.02	$	1.35	$	1.00	$	0.39		N/A

(1) For more information see Note 7 – *Investments in Unconsolidated Affiliates*.

(2) The Net income attributed to TGE was based upon the number of days between the closing of the IPO on May 12, 2015 to December 31, 2015.

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

TGE is a limited partnership that owns, operates, acquires and develops midstream energy assets in North America and has elected to be treated as a corporation for U.S. federal income tax purposes.

Our operations are conducted through, and our operating assets are owned by, our direct and indirect subsidiaries, including Tallgrass Equity, in which we directly own an approximate 55.79% membership interest as of February 8, 2019. We 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 an integrated natural gas storage facility;
- Crude Oil Transportation—the ownership and operation of FERC-regulated crude oil pipeline systems; and

- Gathering, Processing & Terminalling—the ownership and operation of natural gas gathering and processing facilities; crude oil 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."*

Financial Presentation

TGE's operations are conducted through our direct and indirect subsidiaries in Tallgrass Equity and TEP. TGE is the managing member of and therefore controls Tallgrass Equity. Tallgrass Equity, in turn, controls TEP through the direct ownership of 100% of Tallgrass MLP GP, LLC ("TEP GP"), TEP's general partner. As a result, under GAAP, TGE consolidates Tallgrass Equity, TEP GP, TEP, and TEP's subsidiaries. As such, TGE's results of operations will not differ materially from the results of operations of TEP. The most noteworthy reconciling items between TGE's consolidated financial statements and TEP's consolidated financial statements primarily relate to (i) the inclusion of the Tallgrass Equity revolving credit facility prior to repayment and termination on July 26, 2018, (ii) the impact of TGE's election to be treated as a corporation for U.S. federal income tax purposes, and (iii) the presentation of noncontrolling interests in Tallgrass Equity and, prior to the TEP Merger, TEP. The interests in Tallgrass Equity and TEP that are not directly or indirectly owned by TGE will be reflected as being attributable to noncontrolling interests in TGE's consolidated financial statements.

Summary of Results for the Year Ended December 31, 2018

During 2018, we completed the TEP Merger as discussed in Note 1 – *Description of Business*, as well as acquisitions of a 100% membership interest in BNN North Dakota, an additional 2% membership interest in Pony Express, an additional 25.01% membership interest in Rockies Express, a 51% membership interest in Pawnee Terminal and a 100% membership interest in NGL Water Solutions Bakken, LLC. In addition, we issued $500 million in aggregate principal amount of 4.75% senior notes due 2023 (the "2023 Notes"), the proceeds of which were used to repay borrowings under TEP's revolving credit facility.

Net income for the year ended December 31, 2018 was $467.7 million, with Adjusted EBITDA and Cash Available for Dividends (each as defined below under "Non-GAAP Financial Measures") of $654.4 million and $548.7 million, respectively, compared to net income for the year ended December 31, 2017 of $224.0 million, with Adjusted EBITDA and Cash Available for Dividends of $300.3 million and $268.4 million, respectively. The increase in net income, Adjusted EBITDA, and Cash Available for Dividends was largely driven by our increased ownership in TEP due to the TEP Merger, as well as our acquisition of an additional 25.01% membership interest in Rockies Express, as discussed further under "Results of Operations" below.

Recent Developments

TGE Dividend Announced

On January 15, 2019, the Board of Directors of our general partner declared a cash dividend for the quarter ended December 31, 2018 of $0.5200 per Class A share. The distribution will be paid on February 14, 2019, to Class A shareholders of record on January 31, 2019.

Powder River Gateway

In January 2019, we closed on an expansion of our joint venture with Silver Creek. Effective January 1, 2019, we own a 51% membership interest in Powder River Gateway, which holds the Iron Horse Pipeline, the PRE Pipeline, and crude oil terminal facilities in Guernsey, Wyoming. For additional information, see Note 3 – *Acquisitions and Dispositions*.

Blackstone Acquisition

On January 31, 2019, we announced that BIP had entered into a definitive purchase agreement with Kelso, EMG, and Tallgrass KC pursuant to which BIP will acquire 100% of the membership interests in our general partner and an approximate 44% economic interest in us. Subject to customary closing conditions, the Blackstone Acquisition is expected to close within the first quarter of 2019.

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 and early 2018, experiencing some volatility in the second half of 2018. Although price declines and volatility may occur in 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. Additionally, we believe that the U.S. will continue to increase its total volume exported of both natural gas and crude oil as new and additional infrastructure is developed to export these commodities. 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 stabilize and continue to recover.

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 and early 2018, price stability appeared to have generally been restored to the market, but in the second half of 2018 some volatility returned. 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. During 2018, we executed several third party acquisitions, including BNN North Dakota, Deeprock North, an interest in Pawnee Terminal, and NGL Water Solutions Bakken. For additional information, see Note 3 – *Acquisitions and Dispositions*.

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. In the second quarter of 2018, Pony Express Pipeline placed in-service the Platteville Extension Project. During 2017 and 2018, we also announced and are currently executing on the Cheyenne Connector Pipeline and the Iron Horse 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 and 2018, TEP was able to issue an additional $1.6 billion in aggregate principal amount of senior notes with rates from 4.75% to 5.5%.

In addition, the Federal Reserve has continued to incrementally increase short-term interest rates, which marginally impacts the rates on our floating rate revolving credit facility. Changes in the short-term interest rates also affect how our Class A shares are compared and ranked with other yield-oriented securities for investment decision-making purposes. 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. Further, investors could require a higher yield on our Class A shares, potentially decreasing their price, which in turn could limit our ability to complete future equity offerings at favorable pricing. 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 Cash Available for Dividends. Adjusted EBITDA and Cash Available for Dividends 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, and terminalling capacity, NGL transportation capacity, and water transportation, gathering, recycling 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 operating costs and expenses that we evaluate include cost of sales, cost of transportation services, operations and maintenance and general and administrative costs. Operating expenses are driven primarily by expenses related to the operation, maintenance and growth of our asset base.

Adjusted EBITDA and Cash Available for Dividends

Adjusted EBITDA and Cash Available for Dividends 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 midstream infrastructure companies, 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 dividends to our shareholders;
- 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 Cash Available for Dividends provides useful information to investors in assessing our financial condition and results of operations. Adjusted EBITDA and Cash Available for Dividends 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 Cash Available for Dividends be considered alternatives to available cash or other definitions in our partnership agreement. Adjusted EBITDA and Cash Available for Dividends 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 Cash Available for Dividends may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and Cash Available for Dividends 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 and deficiency payments received from or utilized by our customers. We also use Cash Available for Dividends, which we generally define as Adjusted EBITDA, less cash interest costs, maintenance capital expenditures, and certain cash reserves permitted by our governing documents. Adjusted EBITDA and Cash Available for Dividends are both calculated and presented at the Tallgrass Equity level, before consideration of noncontrolling interest associated with the Exchange Right Holders or calculating distributions from Tallgrass Equity to us, on one hand, and to the Exchange Right Holders, on the other. We believe calculating these measures at Tallgrass Equity provides investors the most complete picture of our overall financial and operational results and provides a consistent metric for period over period comparisons that is not impacted by any future exercises by the Exchange Right Holders of the Exchange Right, which does not have a dilutive effect on TGE's net income per share.

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. We collect deficiency payments for volumes committed by our 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 barrels are physically transported and delivered, or when the likelihood that the customer will utilize the deficiency balance becomes remote.

Adjusted EBITDA and Cash Available for Dividends are not presentations made in accordance with GAAP. The following table presents a reconciliation of Adjusted EBITDA to Net income attributable to TGE and net cash provided by operating activities and a reconciliation of Cash Available for Dividends to net cash provided by operating activities, the most directly comparable GAAP financial measures, for each of the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Reconciliation of Tallgrass Equity Adjusted EBITDA to Net income (loss) attributable to TGE			
Net income (loss) attributable to TGE	$ 137,127	$ (128,729)	$ 33,789
Add:			
Interest expense, net [1]	95,465	29,403	16,632
Depreciation and amortization expense [1]	74,998	26,131	25,567
Distributions from unconsolidated investments [1]	302,364	86,551	22,085
Deficiency payments, net [1]	14,443	7,701	9,672
Non-cash compensation expense [1][2]	8,634	2,682	1,862
Loss on debt retirement	2,245	—	—
Deferred income tax expense	55,709	208,458	17,741
Net income attributable to Exchange Right Holders	208,618	137,849	95,882
Less:			
Equity in earnings of unconsolidated investments [1]	(237,197)	(66,922)	(15,287)
(Gain) loss on disposal of assets [1]	(4,630)	(189)	526
Non-cash (gain) loss related to derivative instruments	(3,340)	64	650
Gain on remeasurement of unconsolidated investment [1]	—	(2,744)	—
Tallgrass Equity Adjusted EBITDA	$ 654,436	$ 300,255	$ 209,119
Reconciliation of Tallgrass Equity Adjusted EBITDA and Cash Available for Dividends to Net Cash Provided by Operating Activities			
Net cash provided by operating activities	$ 672,525	$ 571,396	$ 413,298
Add:			
Interest expense, net [1]	95,465	29,403	16,632
Other, including changes in operating working capital [1]	(113,554)	(300,544)	(220,811)
Tallgrass Equity Adjusted EBITDA	$ 654,436	$ 300,255	$ 209,119
Less:			
Cash interest cost [1]	(91,590)	(27,669)	(15,168)
Maintenance capital expenditures, net [1]	(14,176)	(4,179)	(3,270)
Cash flow attributable to predecessor operations	—	—	(2,743)
Tallgrass Equity Cash Available for Dividends	$ 548,670	$ 268,407	$ 187,938

(1) Net of noncontrolling interest associated with less than wholly-owned subsidiaries of Tallgrass Equity.

(2) Represents TGE's portion of non-cash compensation expense related to Equity Participation Shares and TEP's Equity Participation Units, excluding amounts allocated to TD prior to the merger of TD into Tallgrass Development Holdings, LLC, a wholly-owned subsidiary of Tallgrass Equity, on February 7, 2018.

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,		
	2018	2017	2016
		(in thousands)	
Reconciliation of Tallgrass Equity Adjusted EBITDA to Operating Income in the Natural Gas Transportation Segment [1]			
Operating income	$ 69,586	$ 67,434	$ 56,135
Add:			
Depreciation and amortization expense [2]	13,102	5,421	6,099
Distributions from unconsolidated investment [2]	297,496	85,994	21,245
Other, net [2]	2,359	1,424	1,722
Less:			
Adjusted EBITDA attributable to noncontrolling interests	(5,319)	20,738	(10,205)
Non-cash (gain) loss related to derivative instruments [2]	—	(33)	33
Tallgrass Equity Segment Adjusted EBITDA	$ 377,224	$ 180,978	$ 75,029
Reconciliation of Tallgrass Equity Adjusted EBITDA to Operating Income in the Crude Oil Transportation Segment [1]			
Operating income	$ 258,308	$ 190,170	$ 215,784
Add:			
Depreciation and amortization expense [2]	36,578	16,156	15,211
Deficiency payments, net [2]	4,858	7,967	9,123
Less:			
Adjusted EBITDA attributable to noncontrolling interests	(60,414)	(73,385)	(108,093)
Non-cash (gain) loss related to derivative instruments [2]	—	(123)	129
Tallgrass Equity Segment Adjusted EBITDA	$ 239,330	$ 140,785	$ 132,154
Reconciliation of Tallgrass Equity Adjusted EBITDA to Operating Income in the Gathering, Processing & Terminalling Segment [1]			
Operating income (loss)	$ 51,565	$ 33,453	$ (903)
Add:			
Depreciation and amortization expense [2]	21,665	4,554	4,257
Non-cash (gain) loss related to derivative instruments [2]	(3,340)	750	(84)
Distributions from unconsolidated investments [2]	4,868	557	773
Deficiency payments, net [2]	8,540	(458)	550
Other, net [2]	182	142	—
Less:			
(Gain) loss on disposal of assets [2]	(4,630)	(189)	526
Adjusted EBITDA attributable to noncontrolling interests	(19,647)	(22,726)	(1,041)
Tallgrass Equity Segment Adjusted EBITDA	$ 59,203	$ 16,083	$ 4,078
Total Tallgrass Equity Segment Adjusted EBITDA	$ 675,757	$ 337,846	$ 211,261
Corporate general and administrative costs	(21,321)	(37,591)	(2,142)
Total Tallgrass Equity Adjusted EBITDA	$ 654,436	$ 300,255	$ 209,119

(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 20 – *Reportable Segments* to the accompanying consolidated financial statements.

(2) Net of noncontrolling interest associated with less than wholly-owned subsidiaries of Tallgrass Equity.

Results of Operations

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

	Year Ended December 31,		
	2018	2017	2016
	(in thousands, except operating data)		
Natural Gas Transportation Segment:			
TIGT and Trailblazer average firm contracted volumes (MMcf/d) [(1)]	1,636	1,711	1,627
Rockies Express average firm contracted volumes (MMcf/d) [(2)]	4,101	4,101	3,384
Crude Oil Transportation Segment:			
Crude oil transportation average contracted capacity (Bbls/d)	306,936	301,936	295,435
Crude oil transportation average throughput (Bbls/d)	336,314	267,734	285,507
Gathering, Processing & Terminalling Segment:			
Natural gas processing inlet volumes (MMcf/d)	122	109	103
Freshwater average volumes (Bbls/d)	17,849	69,139	13,201
Produced water gathering and disposal average volumes (Bbls/d)	98,489	31,511	11,307

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

(2) Volumes transported under long-term firm fee contracts.

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

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Revenues:			
Crude oil transportation services	$ 398,334	$ 345,733	$ 374,949
Natural gas transportation services	126,894	122,364	119,962
Sales of natural gas, NGLs, and crude oil	168,586	108,503	77,123
Processing and other revenues	99,445	79,298	39,628
Total Revenues	793,259	655,898	611,662
Operating Costs and Expenses:			
Cost of sales	114,815	91,213	71,650
Cost of transportation services	53,068	46,200	47,669
Operations and maintenance	72,460	62,069	55,070
Depreciation and amortization	110,862	90,800	86,247
General and administrative	70,656	65,536	57,298
Taxes, other than income taxes	31,810	28,832	25,400
Contract termination	—	—	8,061
(Gain) loss on disposal of assets	(11,043)	(599)	1,849
Total Operating Costs and Expenses	442,628	384,051	353,244
Operating Income	350,631	271,847	258,418
Other Income (Expense):			
Equity in earnings of unconsolidated investments	306,819	237,110	54,531
Interest expense, net	(133,319)	(89,348)	(45,601)
Gain on remeasurement of unconsolidated investment	—	9,728	—
Other (expense) income, net	(751)	3,106	432
Total Other Income (Expense)	172,749	160,596	9,362
Net income before tax	523,380	432,443	267,780
Deferred income tax expense	(55,709)	(208,458)	(17,741)
Net income	467,671	223,985	250,039
Net income attributable to noncontrolling interests	(330,544)	(352,714)	(216,250)
Net income (loss) attributable to TGE	$ 137,127	$ (128,729)	$ 33,789

Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017

Revenues. Total revenues were $793.3 million for the year ended December 31, 2018 compared to $655.9 million for the year ended December 31, 2017, which represents an increase of $137.4 million, or 21%, in total revenues. The overall increase in revenue was largely driven by increased revenues of $93.5 million and $79.9 million in the Gathering, Processing & Terminalling and Crude Oil Transportation segments, respectively, partially offset by a $35.4 million increase in eliminations of intersegment revenue and decreased revenues of $0.6 million in the Natural Gas Transportation segment, as discussed further below.

Operating costs and expenses. Operating costs and expenses were $442.6 million for the year ended December 31, 2018 compared to $384.1 million for the year ended December 31, 2017, which represents an increase of $58.6 million, or 15%. The overall increase in operating costs and expenses is driven by increased operating costs and expenses of $75.3 million and $11.7 million in the Gathering, Processing & Terminalling and Crude Oil Transportation segments, respectively, partially offset by decreased operating costs and expenses of $25.7 million and $2.7 million in the Corporate and Other and Natural Gas Transportation segments, as discussed further below. The decrease in Corporate and Other expenses was primarily driven by a $35.4 million increase in eliminations of intersegment operating costs and expenses, partially offset by a $4.9 million increase in corporate general and administrative costs and a $4.8 million increase in depreciation and amortization costs due to the administrative assets acquired from TD in February 2018. The increase in corporate general and administrative costs was primarily due to expenses at TEP and Tallgrass Equity attributable to the Merger Agreement and the transactions contemplated by the Merger Agreement, as well as Tallgrass Equity's acquisition of an additional 25.01% membership interest in Rockies Express and additional TEP common units.

Equity in earnings of unconsolidated investments. Equity in earnings of unconsolidated investments was $306.8 million and $237.1 million for the years ended December 31, 2018 and 2017, respectively. Equity in earnings of unconsolidated investments of $306.8 million for the year ended December 31, 2018 primarily reflects our portion of earnings and the $35.9 million of amortization of a negative basis difference associated with our aggregate 75% membership interest in Rockies Express, inclusive of the additional 25.01% membership interest acquired in February 2018, as well as $4.2 million of equity in earnings related to our 51% membership interest in Pawnee Terminal. 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 $23.2 million of amortization of a negative basis difference 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. During the year ended December 31, 2017, Rockies Express recognized a $150 million gain on settlement of the Ultra litigation as discussed in Note 19 – *Legal and Environmental Matters*.

Interest expense, net. Interest expense of $133.3 million for the year ended December 31, 2018 was primarily composed of interest and fees associated with the Senior Notes, as defined in Note 10 – *Long-term Debt*, and the TEP and Tallgrass Equity revolving credit facilities. Interest expense of $89.3 million for the year ended December 31, 2017 was primarily composed of interest and fees associated with TEP and Tallgrass Equity revolving credit facilities and 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. The increase in interest and fees is primarily due to increased borrowings to fund a portion of our 2017 and 2018 acquisitions, as well as the higher borrowing rate on the Senior Notes, the proceeds of which were used to repay borrowings under TEP's revolving credit facility.

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 and Dispositions*.

Other (expense) income, net. Other (expense) 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 expense for the year ended December 31, 2018 was $0.8 million compared to other income of $3.1 million for the year ended December 31, 2017. Other expense of $0.8 million for the year ended December 31, 2018 included a $2.2 million loss on debt retirement associated with the write off of deferred financing costs associated with the Amendment to the TEP revolving credit facility and the termination of the Tallgrass Equity revolving credit facility. Other income of $3.1 million for the year ended December 31, 2017 included a $1.9 million unrealized gain on derivative instrument related to 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 as discussed further in Note 9 – *Risk Management*.

Deferred income tax expense. Deferred income tax expense for the year ended December 31, 2018 was $55.7 million compared to a deferred income tax expense of $208.5 million for the year ended December 31, 2017. The decrease in deferred income tax expense was primarily driven by the remeasurement of the deferred tax asset during the year ended December 31, 2017 as a result of the federal rate change under the tax legislation referred to as the Tax Cuts and Jobs Act that was signed into law on December 22, 2017, partially offset by our increased ownership in TEP due to the TEP Merger and the resulting increase in income allocated to TGE. For additional information, see Note 17 – *Income Taxes.*

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 $384.1 million for the year ended December 31, 2017 compared to $353.2 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 was 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 TEP common units associated with equity-based compensation grants under the TEP GP Long-term Incentive Plan.

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 $23.2 million of amortization of a negative basis difference 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 and Dispositions*. 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 above. 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 $9.1 million of amortization of a negative basis difference 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 19 – *Legal and Environmental Matters*.

Interest expense, net. Interest expense of $89.3 million for the year ended December 31, 2017 was primarily composed of interest and fees associated with the TEP and Tallgrass Equity revolving credit facilities and 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 $45.6 million for the year ended December 31, 2016 was primarily composed of interest and fees associated with TEP and Tallgrass Equity revolving credit facilities 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 and Dispositions*, as well as the higher borrowing rate on the 2024 and 2028 Notes, the proceeds of which were used to repay borrowings under TEP's revolving credit facility.

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 TEP's acquisition of a controlling financial interest in Deeprock Development in July 2017. For additional information, see Note 3 – *Acquisitions and Dispositions.*

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 $3.1 million compared to $0.4 million for the year ended December 31, 2016. Other income of $3.1 million and $0.4 million for the years ended December 31, 2017 and 2016 included a $1.9 million unrealized gain and a $1.3 million unrealized loss, respectively, on derivative instrument related to 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 as discussed further in Note 9 – *Risk Management*.

Deferred income tax expense. Deferred income tax expense for the year ended December 31, 2017 was $208.5 million compared to a deferred income tax expense of $17.7 million for the year ended December 31, 2016. The increase in deferred income tax expense was primarily driven by the remeasurement of the deferred tax asset as a result of the federal rate change under the tax legislation referred to as the Tax Cuts and Jobs Act that was signed into law on December 22, 2017, as well as the increase in taxable income, primarily attributable to the increased equity in earnings associated with Rockies Express as a result of the Ultra settlement. For additional information, see Note 17 – *Income Taxes.*

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,					
	2018		2017		2016	
			(in thousands)			
Revenues:						
Natural gas transportation services	$	131,555	$	129,058	$	125,603
Sales of natural gas, NGLs, and crude oil		1,195		3,412		3,241
Processing and other revenues		7,709		8,551		6,253
Total revenues		140,459		141,021		135,097
Operating costs and expenses:						
Cost of sales		1,382		2,767		3,804
Cost of transportation services		2,990		2,852		5,051
Operations and maintenance		27,185		28,910		28,458
Depreciation and amortization		19,442		19,180		20,976
General and administrative		15,279		15,385		16,335
Taxes, other than income taxes		4,595		4,493		4,338
Total operating costs and expenses		70,873		73,587		78,962
Operating income	$	69,586	$	67,434	$	56,135

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 20 – *Reportable Segments*.

Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017

Revenues. Natural Gas Transportation segment revenues were $140.5 million for the year ended December 31, 2018 compared to $141.0 million for the year ended December 31, 2017, which represents a decrease of $0.6 million in segment revenues due to a $2.2 million decrease in sales of natural gas driven by decreased volumes sold and a $0.8 million decrease in other revenues driven by a decrease in the management fee received by NatGas as a result of the Ultra settlement recognized during the year ended December 31, 2017, as discussed in Note 19 – *Legal and Environmental Matters*, partially offset by a $2.5 million increase in natural gas transportation services due to increased revenue associated with increased throughput and contracted capacity in the second quarter of 2018 and colder weather in the first quarter of 2018, both resulting in higher volumes transported during the first half of 2018.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation segment were $70.9 million for the year ended December 31, 2018 compared to $73.6 million for the year ended December 31, 2017, which represents a decrease of $2.7 million, or 4%. The overall decrease in operating costs and expenses was primarily due to a $1.7 million decrease in operations and maintenance costs driven by decreased pipeline integrity work and a $1.4 million decrease in cost of sales driven by decreased volumes of natural gas sold, partially offset by a $0.3 million increase in depreciation and amortization costs.

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 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. 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 18 – *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 discussed above.

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.

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, 2018	2017	2016
		(in thousands)	
Revenues:			
Crude oil transportation services	$ 437,653	$ 353,395	$ 374,949
Sales of natural gas, NGLs, and crude oil	6,290	11,179	5,554
Processing and other revenues	511	—	—
Total revenues	444,454	364,574	380,503
Operating costs and expenses:			
Cost of sales	8,334	9,680	4,728
Cost of transportation services	68,184	57,284	55,519
Operations and maintenance	12,896	11,838	13,075
Depreciation and amortization	54,237	52,364	51,362
General and administrative	18,486	20,906	20,650
Taxes, other than income taxes	24,009	22,332	19,385
Total operating costs and expenses	186,146	174,404	164,719
Operating income	$ 258,308	$ 190,170	$ 215,784

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 20 – *Reportable Segments*.

Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017

Revenues. Crude Oil Transportation segment revenues were $444.5 million for the year ended December 31, 2018 compared to $364.6 million for the year ended December 31, 2017, which represents an increase of $79.9 million, or 22%, in segment revenues driven by an $84.3 million increase in crude oil transportation services, partially offset by a $4.9 million decrease in sales of crude oil primarily due to decreased volumes sold during the year ended December 31, 2018. The increase in crude oil transportation services revenue was primarily driven by a $55.4 million increase in committed volume shipments, a $37.2 million increase in walk-up barrels shipped, a $6.4 million increase due to the FERC annual index adjustments effective July 1, 2018, and a $5.6 million increase in PLA revenue. These increases were partially offset by a $24.4 million net decrease in revenue from a committed shipper that extended its contract during the fourth quarter of 2017, thereby paying a lower tariff rate, which was partially offset by increased volumes shipped.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation segment were $186.1 million for the year ended December 31, 2018 compared to $174.4 million for the year ended December 31, 2017, which represents an increase of $11.7 million, or 7%. The overall increase in operating costs and expenses was primarily driven by a $10.9 million increase in cost of transportation services driven by higher throughput volumes during the year ended December 31, 2018 compared to the year ended December 31, 2017, a $1.9 million increase in depreciation and amortization costs due to assets placed into service in 2018, and a $1.7 million increase in taxes, other than income taxes driven by an increase in property tax assessment estimates. These increases were partially offset by a $2.4 million decrease in general and administrative costs and a $1.3 million decrease in cost of sales driven by decreased volumes sold.

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 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.

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

Segment Financial Data – Gathering, Processing & Terminalling [1]	Year Ended December 31, 2018	2017	2016
		(in thousands)	
Revenues:			
Sales of natural gas, NGLs, and crude oil	$ 161,101	$ 93,998	$ 68,698
Processing and other revenues	118,564	92,213	44,835
Total revenues	279,665	186,211	113,533
Operating costs and expenses:			
Cost of sales	105,985	80,088	63,746
Cost of transportation services	52,327	20,650	3,942
Operations and maintenance	32,379	21,321	13,537
Depreciation and amortization	32,369	19,256	13,909
General and administrative	12,877	10,035	7,715
Taxes, other than income taxes	3,206	2,007	1,677
Contract termination	—	—	8,061
(Gain) loss on disposal of assets	(11,043)	(599)	1,849
Total operating costs and expenses	228,100	152,758	114,436
Operating income (loss)	$ 51,565	$ 33,453	$ (903)

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 20 – *Reportable Segments*.

Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017

Revenues. Gathering, Processing & Terminalling segment revenues were $279.7 million for the year ended December 31, 2018 compared to $186.2 million for the year ended December 31, 2017, which represents a $93.5 million, or 50%, increase in segment revenues. The increase in segment revenues was primarily due to a $67.1 million increase in sales of natural gas, NGLs, and crude oil and a $26.4 million increase in processing and other revenues. The increase in sales of natural gas, NGLs, and crude oil was driven by (i) increased crude oil sales of $30.3 million at Stanchion, (ii) increased sales of NGLs of $24.2 million primarily due to higher throughput volumes and increased volumes sold driven by the Douglas Gathering System acquisition in June 2017 and higher NGL prices, and (iii) increased sales of natural gas of $12.3 million due to sales of residue gas from the Douglas Gathering System. The increase in processing and other revenues was driven by (i) increased terminal services revenue of $16.2 million driven by the acquisition of Deeprock North in January 2018 and the acquisition of a controlling interest in, and subsequent consolidation of, Deeprock Development in July 2017, (ii) increased water business services revenue of $7.6 million driven by the acquisition of BNN North Dakota in January 2018 and increased produced water disposal volumes, partially offset by decreased fresh water transportation volumes, and (iii) increased processing fee income of $3.9 million primarily driven by changes in the accounting treatment of certain commodities retained as consideration for processing services to processing fee revenue beginning January 1, 2018 as discussed further in Note 12 – *Revenue from Contracts with Customers.*

Operating costs and expenses. Operating costs and expenses in the Gathering, Processing & Terminalling segment were $228.1 million for the year ended December 31, 2018 compared to $152.8 million for the year ended December 31, 2017, which represents an increase of $75.3 million, or 49%. The increase in operating costs and expenses was primarily driven by (i) an increase of $31.7 million in cost of transportation services due to crude oil transportation fees paid by Stanchion, partially offset by decreased fresh water transportation volumes and associated costs, (ii) a $25.9 million increase in cost of sales primarily due to higher NGL prices, higher throughput volumes, and increased volumes sold driven by the Douglas Gathering System acquisition as discussed above, and (iii) increases of $13.1 million, $11.1 million, and $2.8 million in depreciation and amortization, operations and maintenance costs, and general and administrative costs, respectively, all primarily driven by the 2018 acquisitions of BNN North Dakota and Deeprock North and the 2017 acquisitions of the Douglas Gathering System and Deeprock Development. The increase in operating costs and expenses was partially offset by the $11.0 million gain on disposal of assets, primarily driven by the gain on the disposal of TCG during the year ended December 31, 2018, compared to the $0.6 million gain on disposal of assets during the year ended December 31, 2017.

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 June 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.

Liquidity and Capital Resources Overview

Our primary sources of liquidity for the year ended December 31, 2018 were cash generated from operations, proceeds from TEP's issuance of senior notes, and borrowings under TEP's revolving credit facility. We expect our sources of liquidity in the future to include:

- cash generated from our operations;
- borrowing capacity available under TEP's revolving credit facility; and
- future issuances of additional equity and/or debt securities.

We believe that cash on hand, cash generated from operations, and availability under TEP's 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 dividends to shareholders. We believe that future internal growth projects or potential acquisitions will be funded primarily through a combination of cash generated from operations, borrowings under TEP's revolving credit facility and issuances of debt and/or equity securities. For additional information regarding our revolving credit facilities and senior unsecured notes, see Note 10 – *Long-term Debt*. For additional information regarding our equity transactions, see Note 11 – *Partnership Equity*.

Our total liquidity as of December 31, 2018 and 2017 was as follows:

	December 31, 2018	December 31, 2017
	(in thousands)	
Cash on hand	$ 9,596	$ 2,593
Total capacity under the TEP revolving credit facility [1]	2,250,000	1,750,000
Less: Outstanding borrowings under the TEP revolving credit facility	(1,224,000)	(661,000)
Less: Letters of credit issued under the TEP revolving credit facility	(94)	(94)
Available capacity under the TEP revolving credit facility	1,025,906	1,088,906
Total capacity under the Tallgrass Equity revolving credit facility	—	150,000
Less: Outstanding borrowings under the Tallgrass Equity revolving credit facility [2]	—	(146,000)
Available capacity under the Tallgrass Equity revolving credit facility	—	4,000
Total liquidity	$ 1,035,502	$ 1,095,499

(1) In July 2018, the TEP revolving credit facility was amended, increasing the total capacity to $2.25 billion. See Note 10 – *Long-term Debt* for additional information.

(2) On July 26, 2018, Tallgrass Equity repaid all outstanding borrowings and terminated its revolving credit facility. See Note 10 – *Long-term Debt* for additional information.

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 TEP's 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, 2018, we had a working capital deficit of $146.9 million compared to a working capital deficit of $101.6 million at December 31, 2017, which represents an increase in the working capital deficit of $45.4 million. The overall increase in the working capital deficit was primarily attributable to changes in the following components:

- an increase in accounts payable and accrued liabilities of $110.0 million primarily due to crude oil purchases at Stanchion, an increase in accrued payroll, an increase in capital expenditures at Terminals, and payables related to BNN North Dakota and NGL Water Solutions Bakken acquired in January 2018 and November 2018, respectively, partially offset by a decrease in capital expenditures at Pony Express;
- an increase in other current liabilities of $31.7 million, primarily driven by the recognition of a $25 million liability at PLT as discussed in Note 3 – *Acquisitions and Dispositions;*
- an increase in deferred revenue of $22.6 million primarily from deficiency payments collected by Pony Express and deferred revenue at BNN Colorado, which was consolidated in December 2018; and
- an increase in accrued interest of $14.1 million primarily due to increased borrowings to fund a portion of our 2018 acquisitions, as well as the higher borrowing rate on the Senior Notes, the proceeds of which were used to repay borrowings under TEP's revolving credit facility.

These working capital decreases were partially offset by:

- an increase in accounts receivable of $116.1 million primarily due to crude oil sales at Stanchion, as well as receivables related to BNN North Dakota assets acquired during 2018, and BNN Colorado, which was consolidated in December 2018; and
- an increase in inventory of $12.7 million primarily due to crude oil purchases at Stanchion and PLA barrels retained at Pony Express.

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

Cash Flows

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

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Net cash provided by (used in):			
Operating activities	$ 672,525	$ 571,396	$ 413,298
Investing activities	$ (987,212)	$ (898,541)	$ (595,539)
Financing activities	$ 321,690	$ 327,279	$ 182,466

Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017

Operating Activities. Cash flows provided by operating activities were $672.5 million and $571.4 million for the years ended December 31, 2018 and 2017, respectively. The increase in net cash flows provided by operating activities of $101.1 million was primarily driven by the increase in operating results, as discussed above, and a $69.7 million increase in distributions received from unconsolidated affiliates, primarily Rockies Express, as a result of our increased membership interest effective March 31, 2017 and February 7, 2018. These increases were partially offset by a net decrease in cash flows from changes in working capital driven by a $44.2 million decrease in net cash inflows from accounts receivable, primarily due to crude oil sales at Stanchion, partially offset by a $27.7 million decrease in net cash outflows from accounts payable, primarily due to crude oil purchases at Stanchion.

Investing Activities. Cash flows used in investing activities were $987.2 million for the year ended December 31, 2018, primarily driven by:

- contributions to unconsolidated investments in the amount of $473.9 million, primarily to fund our portion of the repayment of Rockies Express' $550 million of 6.85% senior notes due July 15, 2018, as well as to fund our share of capital projects at Iron Horse and BNN Colorado;
- capital expenditures of $368.9 million, primarily due to spending on the Cheyenne Connector, a new 70-mile natural gas pipeline located in Colorado, additional water gathering infrastructure located in North Dakota, a 55-mile extension on the Pony Express system, construction of the Buckingham Terminal expansion, construction of the Guernsey, Natoma, and Grasslands Terminals, and pipe replacement and remediation work on the Trailblazer Pipeline system as discussed in Note 19 – *Legal and Environmental Matters*;
- cash outflows of $95.0 million for the acquisition of a 100% membership interest in BNN North Dakota;
- cash outflows of $91.0 million for the acquisition of a 100% membership interest in NGL Water Solutions Bakken;
- cash outflows of $30.7 million for the initial capital contribution and formation of PLT;
- cash outflows of $30.6 million for the acquisition of a 51% membership interest in Pawnee Terminal; and
- cash outflows of $19.5 million for the acquisition of a 38% membership interest in Deeprock North.

These cash outflows were partially offset by cash inflows of:

- $80.2 million of distributions received from unconsolidated affiliates in excess of cumulative earnings recognized, primarily Rockies Express; and
- $50.0 million from the sale of TCG.

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 19 – *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.

Financing Activities. Cash flows provided by financing activities were $321.7 million for the year ended December 31, 2018, primarily driven by:

- proceeds of $500.0 million from the issuance of TEP's 2023 Notes; and
- net borrowings under the revolving credit facilities of $417.0 million.

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

- distributions to noncontrolling interests of $327.6 million, consisting of Tallgrass Equity distributions to the Exchange Right Holders of $223.7 million, distributions to TEP unitholders of $97.7 million, and distributions to Deeprock Development and Pony Express noncontrolling interests of $6.2 million;
- dividends paid to Class A shareholders of $206.4 million; and
- cash outflows of $50.0 million for the acquisition of an additional 2% membership interest in Pony Express.

Cash flows provided by financing activities were $327.3 million for the year ended December 31, 2017, primarily driven by:

- proceeds from TEP's 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 TEP common units under its Equity Distribution Agreements.

These cash inflows were partially offset by cash outflows of:

- net repayments under the revolving credit facilities of $356.0 million;
- distributions to noncontrolling interests of $317.1 million, consisting of distributions to TEP unitholders of $185.7 million, Tallgrass Equity distributions to the Exchange Right Holders of $125.2 million, and distributions to Pony Express noncontrolling interests of $6.2 million;
- dividends paid to Class A shareholders of $73.3 million;
- $72.4 million for the exercise of the remainder of the call option granted by TD covering 1,703,094 TEP common units;
- $35.3 million for the 736,262 TEP common units repurchased from TD; and
- deferred financing costs of $22.4 million from the issuance of the 2024 and 2028 Notes and the amendment to TEP's revolving credit facility.

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

Operating Activities. Cash flows provided by operating activities were $571.4 million and $413.3 million for the years ended December 31, 2017 and 2016, respectively. The increase in net cash flows provided by operating activities of $158.1 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. Investing cash outflows for the year ended December 31, 2017 were primarily driven by 2017 acquisitions, capital expenditures, and contributions to Rockies Express, as discussed above.

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;
- 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; and
- 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.

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 $327.3 million for the year ended December 31, 2017, primarily driven by proceeds from the issuance of the 2024 and 2028 Notes and issuance of TEP common units, partially offset by net repayments under the revolving credit facilities, distributions to noncontrolling interests, dividends paid to Class A shareholders, the partial exercise of the call option granted by TD, the repurchase of common units from TD, and payments for deferred financing costs, as discussed above.

Cash flows provided by financing activities were $182.5 million for the year ended December 31, 2016, primarily driven by:

- proceeds from TEP's 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 TEP common units under its Equity Distribution Agreements;
- net borrowings under the TEP revolving credit facility of $262.0 million;
- net cash proceeds of $90.0 million from TEP's 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 19 – *Legal and Environmental Matters.*

These 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 noncontrolling interests of $249.1 million, consisting of distributions to TEP unitholders of $145.1 million, Tallgrass Equity distributions to the Exchange Right Holders of $97.5 million, and distributions to Pony Express and Water Solutions noncontrolling interests of $6.5 million;
- $204.6 million for TEP's partial exercise of the call option granted by TD covering 4,814,906 TEP common units; and
- dividends paid to TGE Class A shareholders of $42.5 million.

Dividends

Dividends to our Class A shareholders. We distribute 100% of TGE's available cash at the end of each quarter to Class A shareholders of record beginning with the quarter ended June 30, 2015. Available cash at TGE is generally defined in our partnership agreement as all cash and cash equivalents on hand at the date of determination in respect of such quarter less reserves established in the discretion of our general partner for future requirements. For a discussion of factors and trends impacting our business, which in turn impacts our ability to pay dividends to our Class A shareholders, please see *"—Factors and Trends Impacting Our Business"* above.

Our dividend for the three months ended December 31, 2018, in the amount of $0.5200 per Class A share, or $81.3 million in the aggregate, was announced on January 15, 2019 and will be paid on February 14, 2019 to Class A shareholders of record on January 31, 2019.

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).

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. We expect to incur approximately $270 million for expansion capital projects and approximately $40 million for maintenance capital expenditures in 2019. The following table summarizes the maintenance and expansion capital expenditures incurred at our consolidated entities:

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Maintenance capital expenditures	$ 20,956	$ 14,822	$ 11,323
Expansion capital expenditures	353,672	135,604	44,348
Total capital expenditures incurred	$ 374,628	$ 150,426	$ 55,671

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 $21.0 million for the year ended December 31, 2018 from $14.8 million for the year ended December 31, 2017 is primarily driven by increased expenditures in the Corporate and Other and Gathering, Processing & Terminalling segments. Maintenance capital expenditures for the year ended December 31, 2018 in the Corporate and Other segment consisted primarily of spending on information technology assets as a result of our acquisition of these assets from TD in February 2018 as discussed in Note 3 – *Acquisitions and Dispositions*. 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. Expansion capital expenditures were $353.7 million for the year ended December 31, 2018 compared to $135.6 million for the year ended December 31, 2017. Expansion capital expenditures for the year ended December 31, 2018 consisted primarily of spending on the Cheyenne Connector, additional water gathering infrastructure located in North Dakota, PLT, a 55-mile extension on the Pony Express system, construction of the Buckingham Terminal expansion, construction of the Guernsey, Natoma, and Grasslands Terminals, and pipe replacement and remediation work on the Trailblazer Pipeline system as discussed in Note 19 – *Legal and Environmental Matters*. 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.

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. Expansion capital expenditures were $135.6 million for the year ended December 31, 2017 compared to $44.3 million for the year ended December 31, 2016. Expansion capital expenditures for the year ended December 31, 2017 consisted primarily of spending at Water Solutions, the Grasslands Terminal and the Natoma Terminal, and the Pony Express system, as discussed above. Expansion capital expenditures 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.

During the years ended December 31, 2018, 2017, and 2016, we invested cash in unconsolidated affiliates, including Rockies Express, Iron Horse, and BNN Colorado prior to our consolidation of BNN Colorado in December 2018, of $473.9 million, $45.9 million, and $50.1 million, respectively, to fund our share of capital projects, including (i) a special contribution of approximately $412.5 million to fund our portion of the repayment of Rockies Express' $550 million of 6.85% senior notes due July 15, 2018 and (ii) an initial contribution of $3.5 million to Iron Horse, a newly formed unconsolidated affiliate in February 2018. In connection with our 51% membership interest in Powder River Gateway effective January 1, 2019, we made commitments to fund our proportionate share of the remaining cost to construct the Iron Horse pipeline, estimated at $25.4 million.

We intend to pay dividends to our Class A shareholders. Due to our cash distribution policy, we expect that we will distribute available cash to our Class A shareholders on a quarterly basis. We expect to fund future capital expenditures with funds generated from operations, borrowings under our revolving credit facility, and/or the issuance of equity or 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, 2018:

	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]	$ 3,224,000	$ —	$ —	$ 1,724,000	$ 1,500,000
Interest on debt obligations [2]	900,065	158,624	317,391	228,342	195,708
Operating lease and service contract obligations [3]	3,230	1,074	1,405	387	364
Capital lease obligations [4]	20,015	449	898	898	17,770
Land site lease and right-of-way [5]	6,029	744	1,408	1,088	2,789
Other purchase commitments [6]	95,422	53,098	17,875	11,218	13,231
Total	$ 4,248,761	$ 213,989	$ 338,977	$ 1,965,933	$ 1,729,862

(1) Debt obligations at December 31, 2018 consisted of borrowings under the TEP revolving credit facility and the Senior 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, 2018. 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 13 – *Commitments & Contingent Liabilities*.

(4) Capital lease obligations consist of the PLT land site lease. For additional information, see Note 13 – *Commitments & Contingent Liabilities.*

(5) 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 13 – *Commitments & Contingent Liabilities*.

(6) Other purchase commitments primarily relate to planned non-reimbursable capital expenditures and operating and maintenance expenditures.

All of our employees are employed by Tallgrass Management, LLC ("Tallgrass Management"). Prior to July 1, 2018, Tallgrass Management was a wholly-owned subsidiary of Tallgrass Energy Holdings. In connection with the closing of the TEP initial public offering on May 17, 2013, TEP and TEP GP 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. In addition, in connection with the closing of the TGE initial public offering on May 12, 2015 (the "TGE IPO"), TGE entered into an Omnibus Agreement (the "TGE Omnibus Agreement") with Tallgrass Energy GP, LLC (formerly known as TEGP Management, LLC), Tallgrass Equity and Tallgrass Energy Holdings. Effective July 1, 2018, Tallgrass Management was contributed to Tallgrass Equity in connection with the TEP Merger. As a result, the costs of employer and director compensation and benefits are now incurred directly by Tallgrass Equity.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting 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
Business Combinations		
We allocate the cost of each acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recorded. We are required to recognize intangible assets separately from goodwill. Any excess purchase price after the fair value of the net tangible and identifiable intangible assets acquired, as well as noncontrolling interest, if applicable, is determined is recognized as goodwill.	We measure the fair value of assets acquired and liabilities assumed in business combinations using widely accepted valuation techniques, primarily discounted cash flow, cost approach, and market multiple analyses. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. These analyses require management to apply significant judgment in estimating future cash flows as well as fair values of individual assets, 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 estimates or assumptions used to complete the purchase price allocation and estimate the fair value of acquired assets, liabilities and noncontrolling interests significantly differed from assumptions made, the allocation of purchase price between goodwill, intangibles, noncontrolling interests, equity method investments and property, plant, and equipment could significantly differ. Such a difference would impact future earnings through depreciation and amortization expense. In addition, if forecasts supporting the valuation of the intangible assets or goodwill are not achieved, impairments could arise. Further, if customer relationships terminate prior to the expected useful life, we will be required to record a charge to operations to write-off any remaining unamortized balance of the intangible asset assigned to that customer.

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, 2018. 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.
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 use either the qualitative assessment option or proceed directly to the quantitative impairment test depending on facts and circumstances of the reporting unit, including the forecasted useful lives of the assets, the probability of different outcomes, including anticipated volumes, contract renewals and changes in our regulated rates, and the discount rate that reflects the risk inherent in future cash flows. When quantitative assessments are made, we determine fair value using widely accepted valuation techniques, primarily discounted cash flow and market multiple analyses. 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. We incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. 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. 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.	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 2018 using the methodology described herein, and determined there was no impairment.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Revenue Recognition		
The majority of our revenue is derived from long-term contracts that can span several years. Accounting for long-term contracts involves the use of various techniques to estimate total contract revenue and determine the timing of revenue recognition. We periodically evaluate our estimates with respect to the probability of our customers exercising their rights and recognize revenue associated with contract liabilities when the probability becomes remote that the customer will exercise its remaining rights.	We review our deferred revenue (contract liabilities) at each balance sheet date to determine the probability that our customers will exercise their remaining rights. We recognize revenue when the probability becomes remote that the customer will exercise its remaining rights. Our evaluation requires management to apply judgment in contract renewal assumptions and estimating future system capacity and the ability of our customers to utilize that capacity.	If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, the timing of our revenue recognition with respect to deferred revenue could be impacted and we may experience material changes in revenue.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

For the year ended December 31, 2018, the percentage of our firm fee, volumetric fee, and commodity exposed Adjusted EBITDA was 90%, 6%, and 4%, respectively. Historically, we have had a limited amount of direct commodity price exposure related to natural gas collected for electrical compression costs at TIGT, natural gas used at TMID and crude oil collected as part of our contractual pipeline loss allowance at Pony Express and Terminals. Accordingly, we have historically entered into derivative contracts with third parties for all or a portion of these volumes for the purpose of hedging our commodity price exposures. In addition, Stanchion transacts in crude oil and enters into physical and financial derivative contracts in connection with these, and other, 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 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, 2018, assuming a parallel shift in the forward curve:

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
		(in thousands)	
Crude oil derivative contract assets (1)	$ 3,526	$ (1,221)	$ 1,221
Crude oil derivative contract liabilities (1)	$ (1,642)	$ (424)	$ 424

(1) Represents the net forward sale of 362,000 barrels of crude oil in our Gathering, Processing & Terminalling segment which will settle throughout 2019.

Interest Rate Risk

As described in Note 10 – *Long-term Debt*, on July 26, 2018, in connection with the Amendment to TEP's Credit Agreement, Tallgrass Equity repaid all outstanding borrowings and terminated its revolving credit facility.

As of December 31, 2018, TEP has issued $2.0 billion of Senior Notes and has a $2.25 billion revolving credit facility with borrowings of $1.22 billion. Borrowings under TEP's 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 0.25% to 1.25% for base rate borrowings (previously 0.50% to 1.50% prior to the Amendment) and 1.25% to 2.25% for reserve adjusted Eurodollar rate borrowings (previously 1.50% to 2.50% prior to the Amendment), based upon TEP's total leverage ratio.

We do not currently hedge the interest rate risk on our borrowings under TEP's 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 $0.6 million based on our outstanding debt under TEP's revolving credit facility as of December 31, 2018.

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 BBB- or Baa3 and better credit ratings or are part of corporate families with such credit ratings as of December 31, 2018.

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 Energy GP, LLC, the general partner of Tallgrass Energy, LP, and the shareholders of Tallgrass Energy, LP

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Tallgrass Energy, LP and its subsidiaries (the "Partnership") as of December 31, 2018 and 2017, and the related consolidated statements of income, equity and cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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, 2018 and 2017, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2018 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, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 2 and 12 to the consolidated financial statements, Rockies Express Pipeline LLC, an investment of the Partnership accounted for under the equity method, changed the manner in which it accounts for revenue in 2018.

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.

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 8, 2019

We have served as the Partnership's auditor since 2015.

TALLGRASS ENERGY, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,596	$ 2,593
Accounts receivable, net	236,097	119,955
Inventories	34,316	21,609
Prepayments and other current assets	11,816	13,165
Total Current Assets	291,825	157,322
Property, plant and equipment, net	2,802,429	2,394,337
Goodwill	421,983	404,838
Intangible assets, net	227,103	97,731
Unconsolidated investments	1,861,686	909,531
Deferred financing costs, net	10,990	12,563
Deferred tax asset	273,531	312,997
Deferred charges and other assets	3,962	2,694
Total Assets	$ 5,893,509	$ 4,292,013
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts payable	$ 201,512	$ 104,224
Accrued taxes	20,734	19,272
Accrued interest	39,217	25,167
Accrued liabilities	23,287	10,540
Deferred revenue	111,095	88,471
Other current liabilities	42,910	11,202
Total Current Liabilities	438,755	258,876
Long-term debt, net	3,205,958	2,292,993
Other long-term liabilities and deferred credits	31,688	18,965
Total Long-term Liabilities	3,237,646	2,311,958
Commitments and Contingencies		
Equity:		
Class A Shareholders (156,311,986 and 58,085,002 shares outstanding at December 31, 2018 and 2017, respectively)	1,725,537	48,613
Class B Shareholders (123,887,893 and 99,154,440 shares outstanding at December 31, 2018 and 2017, respectively)	—	—
Total Partners' Equity	1,725,537	48,613
Noncontrolling interests [(a)]	491,571	1,672,566
Total Equity	2,217,108	1,721,179
Total Liabilities and Equity	$ 5,893,509	$ 4,292,013

(a) See Note 11 - *Partnership Equity* for a complete description of our noncontrolling interests.

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

TALLGRASS ENERGY, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2018	2017	2016
	(in thousands, except per unit amounts)		
Revenues:			
Crude oil transportation services	$ 398,334	$ 345,733	$ 374,949
Natural gas transportation services	126,894	122,364	119,962
Sales of natural gas, NGLs, and crude oil	168,586	108,503	77,123
Processing and other revenues	99,445	79,298	39,628
Total Revenues	793,259	655,898	611,662
Operating Costs and Expenses:			
Cost of sales	114,815	91,213	71,650
Cost of transportation services	53,068	46,200	47,669
Operations and maintenance	72,460	62,069	55,070
Depreciation and amortization	110,862	90,800	86,247
General and administrative	70,656	65,536	57,298
Taxes, other than income taxes	31,810	28,832	25,400
Contract termination	—	—	8,061
(Gain) loss on disposal of assets	(11,043)	(599)	1,849
Total Operating Costs and Expenses	442,628	384,051	353,244
Operating Income	350,631	271,847	258,418
Other Income (Expense):			
Equity in earnings of unconsolidated investments	306,819	237,110	54,531
Interest expense, net	(133,319)	(89,348)	(45,601)
Gain on remeasurement of unconsolidated investment	—	9,728	—
Other (expense) income, net	(751)	3,106	432
Total Other Income (Expense)	172,749	160,596	9,362
Net income before tax	523,380	432,443	267,780
Deferred income tax expense	(55,709)	(208,458)	(17,741)
Net income	467,671	223,985	250,039
Net income attributable to noncontrolling interests	(330,544)	(352,714)	(216,250)
Net income (loss) attributable to TGE	$ 137,127	$ (128,729)	$ 33,789
Allocation of income:			
Net income (loss) attributable to TGE	$ 137,127	$ (128,729)	$ 33,789
Predecessor operations interest in net income	—	—	(6,995)
Net income (loss) attributable to TGE, excluding predecessor operations interest	137,127	(128,729)	26,794
Basic net income (loss) per Class A share	$ 1.27	$ (2.22)	$ 0.55
Diluted net income (loss) per Class A share	$ 1.27	$ (2.22)	$ 0.55
Basic average number of Class A shares outstanding	107,586	58,076	48,856
Diluted average number of Class A shares outstanding	109,817	58,076	48,889

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

TALLGRASS ENERGY, LP
CONSOLIDATED STATEMENTS OF EQUITY

		Partners' Capital					
		Class A Shares		Class B Shares			
	Predecessor Equity	Shares	Amount	Shares	Amount	Noncontrolling Interests	Total Equity
				(in thousands)			
Balance at January 1, 2016	$ 71,564	47,725	$ 422,310	109,504	$ —	$ 1,599,188	$ 2,093,062
Net Income	6,995	—	26,794	—	—	216,250	250,039
Acquisition of additional 31.3% membership interest in Pony Express	—	—	(255,617)	—	—	(173,422)	(429,039)
Issuance of TEP units to public, net of offering costs	—	—	28,762	—	—	308,909	337,671
Distributions to noncontrolling interests	—	—	—	—	—	(249,142)	(249,142)
Partial exercise of call option	—	—	(27,312)	—	—	(211,315)	(238,627)
Issuance of TEP common units in a private placement, net of offering costs	—	—	7,592	—	—	82,417	90,009
Deferred tax asset	—	—	86,766	—	—	—	86,766
Dividends paid to Class A Shareholders	—	—	(42,499)	—	—	—	(42,499)
Contributions from noncontrolling interests	—	—	—	—	—	9,304	9,304
Noncash compensation expense	—	—	1,448	—	—	7,879	9,327
Acquisition of membership interest in BNN	—	—	(464)	—	—	(5,536)	(6,000)
Contributions from TD	—	—	5,827	—	—	12,067	17,894
Costs associated with equity issuance	—	—	(986)	—	—	—	(986)
TEP LTIP units tendered by employees to satisfy tax withholding obligations	—	—	(51)	—	—	(447)	(498)
Distribution of excess TGE IPO proceeds to Exchange Right Holders	—	—	(1,603)	—	—	—	(1,603)
Contributions from Predecessor Entities, net	3,736	—		—	—	—	3,736
Conversion of Class B shares to Class A shares.	—	10,350	—	(10,350)	—	—	—
Balance at December 31, 2016	$ 82,295	58,075	$ 250,967	99,154	$ —	$ 1,596,152	$ 1,929,414
Acquisition of Terminals and NatGas	(82,295)	—	(21,314)	—	—	(36,391)	(140,000)
Net income	—	—	(128,729)	—	—	352,714	223,985
Issuance of TEP units to public, net of offering costs	—	—	11,353	—	—	101,067	112,420
Dividends paid to Class A Shareholders	—	—	(73,321)	—	—	—	(73,321)
Noncash compensation expense	—	—	1,603	—	—	10,390	11,993
Issuance of TGE Class A shares under TGE LTIP plan	—	10	—	—	—	—	—
TEP LTIP units tendered by employees to satisfy tax withholding obligations	—	—	(1,317)	—	—	(11,616)	(12,933)
Partial exercise of call option	—	—	(12,052)	—	—	(72,890)	(84,942)
Repurchase of TEP common units from TD	—	—	(3,618)	—	—	(31,717)	(35,335)
Acquisition of additional 24.99% membership interest in Rockies Express	—	—	23,522	—	—	40,159	63,681
Acquisition of additional 40% membership interest in Deeprock Development	—	—	—	—	—	45,869	45,869
Acquisition of noncontrolling interests	—	—	669	—	—	(7,109)	(6,440)
Contributions from TD	—	—	850	—	—	1,451	2,301
Contributions from noncontrolling interests	—	—	—	—	—	1,589	1,589
Distributions to noncontrolling interests	—	—	—	—	—	(317,102)	(317,102)
Balance at December 31, 2017	$ —	58,085	$ 48,613	99,154	$ —	$ 1,672,566	$ 1,721,179
Cumulative effect of ASC 606 implementation	—	—	4,588	—	—	39,543	44,131
Net income	—	—	137,127	—	—	330,544	467,671
Dividends paid to Class A Shareholders	—	—	(206,431)	—	—	—	(206,431)
Noncash compensation expense	—	—	6,296	—	—	3,197	9,493
Acquisition of additional TEP common units from TD	—	—	(62,223)	10,758	—	(189,520)	(251,743)
Issuance of Tallgrass Equity units	—	—	—	—	—	644,782	644,782

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

TALLGRASS ENERGY, LP
CONSOLIDATED STATEMENTS OF EQUITY

	Predecessor Equity	Partners' Capital: Class A Shares: Shares	Partners' Capital: Class A Shares: Amount	Partners' Capital: Class B Shares: Shares	Partners' Capital: Class B Shares: Amount	Noncontrolling Interests	Total Equity
				(in thousands)			
Acquisition of additional 25.01% membership interest in Rockies Express	—	—	34,116	16,797	—	74,421	108,537
Acquisition of additional 2% membership interest in Pony Express	—	—	(5,268)	—	—	(44,732)	(50,000)
Consolidation of Deeprock North	—	—	—	—	—	31,843	31,843
Consolidation of BNN Colorado	—	—	—	—	—	10,138	10,138
Contributions from noncontrolling interests	—	—	—	—	—	1,787	1,787
Distributions to noncontrolling interests	—	—	—	—	—	(327,578)	(327,578)
Issuance of TEP units to the public, net of offering costs	—	—	(98)	—	—	(279)	(377)
TEP LTIP units tendered by employees to satisfy tax withholding obligations	—	—	(190)	—	—	(1,531)	(1,721)
Issuance of Class A shares under LTIP plan, net of units tendered by employees to satisfy tax withholding obligations	—	19	(30)	—	—	—	(30)
Conversion of Class B shares to Class A shares.	—	2,822	(8,717)	(2,822)	—	8,717	—
Deferred tax asset	—	—	15,427	—	—	—	15,427
Acquisition of additional TEP common units	—	—	(351,431)	—	—	(1,762,327)	(2,113,758)
Issuance of Class A shares	—	95,386	2,113,758	—	—	—	2,113,758
Balance at December 31, 2018	$ —	156,312	$1,725,537	123,887	$ —	$ 491,571	$ 2,217,108

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

TALLGRASS ENERGY, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Cash Flows from Operating Activities:			
Net income	$ 467,671	$ 223,985	$ 250,039
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	117,430	98,537	94,038
Equity in earnings of unconsolidated investments	(306,819)	(237,110)	(54,531)
Distributions from unconsolidated investments	306,934	237,192	54,449
Deferred income tax expense	55,709	208,458	17,741
Gain on remeasurement of unconsolidated investment	—	(9,728)	—
Other noncash items, net	(2,382)	9,226	9,711
Changes in components of working capital:			
Accounts receivable and other	(102,105)	(57,927)	2,835
Accounts payable and accrued liabilities	112,474	84,731	10,684
Deferred revenue	17,547	27,283	33,815
Other current assets and liabilities	(3,079)	(10,542)	(5,578)
Other operating, net	9,145	(2,709)	95
Net Cash Provided by Operating Activities	672,525	571,396	413,298
Cash Flows from Investing Activities:			
Contributions to unconsolidated investments	(473,946)	(45,948)	(50,076)
Capital expenditures	(368,873)	(145,144)	(84,491)
Acquisition of BNN North Dakota, net of cash acquired	(95,000)	—	—
Acquisition of NGL Water Solutions Bakken	(91,000)	—	—
Distributions from unconsolidated investments in excess of cumulative earnings	80,213	69,434	24,120
Sale of Tallgrass Crude Gathering	50,046	—	—
Acquisition of membership interest in PLT	(30,704)	—	—
Acquisition of membership interest in Pawnee Terminal	(30,600)	—	—
Acquisition of 38% membership interest in Deeprock North	(19,500)	—	—
Acquisition of Rockies Express membership interest	—	(400,000)	(436,022)
Acquisition of Terminals and NatGas	—	(140,000)	—
Acquisition of Douglas Gathering System	—	(128,526)	—
Acquisition of Deeprock Development, net of cash acquired	—	(57,202)	—
Acquisition of PRB Crude System	—	(36,030)	—
Acquisition of Pony Express membership interest	—	—	(49,118)
Other investing, net	(7,848)	(15,125)	48
Net Cash Used in Investing Activities	(987,212)	(898,541)	(595,539)
Cash Flows from Financing Activities:			
Proceeds from issuance of long-term debt	500,000	1,103,750	400,000
Borrowings (repayments) under revolving credit facilities, net	417,000	(356,000)	262,000
Distributions to noncontrolling interests	(327,578)	(317,102)	(249,142)
Dividends paid to Class A shareholders	(206,431)	(73,321)	(42,499)
Acquisition of Pony Express membership interest	(50,000)	—	(425,882)
Proceeds from public offering of TEP common units, net of offering costs	—	112,420	337,671

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

Partial exercise of call option		—		(72,381)		(204,634)
Repurchase of TEP common units from TD		—		(35,335)		—
Payments for deferred financing costs		—		(22,375)		(10,380)
Proceeds from private placement of TEP common units, net of offering costs		—		—		90,009
Contribution from TD		—		—		17,894
Other financing, net		(11,301)		(12,377)		7,429
Net Cash Provided by Financing Activities		321,690		327,279		182,466
Net Change in Cash and Cash Equivalents		7,003		134		225
Cash and Cash Equivalents, beginning of period		2,593		2,459		2,234
Cash and Cash Equivalents, end of period	$	9,596	$	2,593	$	2,459

Supplemental Disclosures:						
Cash payments for interest, net	$	(114,026)	$	(72,698)	$	(34,367)
Schedule of Noncash Investing and Financing Activities:						
Acquisition of additional TEP common units [(a)(b)]	$	(2,365,501)	$	—	$	—
Issuance of Class A shares [(a)]	$	2,113,758	$	—	$	—
Issuance of Tallgrass Equity units [(b)]	$	644,782	$	—	$	—
Acquisition of Rockies Express membership interest [(b)]	$	(393,039)	$	—	$	—
Contribution of 38% membership interest in Deeprock North to Deeprock Development	$	(19,500)	$	—	$	—
Issuance of noncontrolling interests in Deeprock Development in exchange for 62% membership interest in Deeprock North	$	(31,843)	$	—	$	—
TEP common units issued as partial consideration to acquire additional 9% membership interest in Deeprock Development	$	—	$	6,617	$	—
Increase in accrual for payment of property, plant and equipment	$	5,755	$	8,975	$	—

(a) Represents the acquisition of additional TEP common units in exchange for Class A shares associated with the Merger Agreement as discussed in Note 1 – *Description of Business.*

(b) Represents the issuance of Tallgrass Equity units associated with our acquisition of a 25.01% membership interest in Rockies Express and an additional 5,619,218 TEP common units as discussed in Note 3 – *Acquisitions and Dispositions.*

TALLGRASS ENERGY, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business

Tallgrass Energy, LP ("TGE") formerly known as Tallgrass Energy GP, LP, is a limited partnership that owns, operates, acquires and develops midstream energy assets in North America and has elected to be treated as a corporation for U.S. federal income tax purposes. "We," "us," "our" and similar terms refer to TGE together with its consolidated subsidiaries.

Our operations are conducted through, and our operating assets are owned by, our direct and indirect subsidiaries, including Tallgrass Equity, LLC ("Tallgrass Equity"), in which we directly own an approximate 55.79% membership interest as of December 31, 2018. We 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 an integrated natural gas storage facility;
- 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 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 75% 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"), and our 100% membership interest in Tallgrass NatGas Operator, LLC ("NatGas"), 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, Kansas, and the surrounding regions through Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which owns a FERC-regulated crude oil pipeline commencing in both Guernsey, Wyoming and Weld County, Colorado and terminating in Cushing, Oklahoma (the "Pony Express System"). In the second quarter of 2018, Pony Express placed into service an extension of the system from an additional origin point in Weld County, Colorado located near Platteville, Colorado.

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"), (2) natural gas processing facilities in Casper and Douglas, and (3) a natural gas treating facility at West Frenchie Draw. We also provide 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, Wyoming, and North Dakota through BNN Water Solutions, LLC ("Water Solutions"), and crude oil storage and terminalling services through our 100% membership interest in Tallgrass Terminals, LLC ("Terminals"), which owns and operates crude oil terminals in Colorado, Oklahoma, and Kansas. The Gathering, Processing & Terminalling segment also includes Stanchion Energy, LLC ("Stanchion"), which transacts in crude oil.

The term "Terminals Predecessor" refers to Terminals and the term "NatGas Predecessor" refers to NatGas prior to their acquisition by Tallgrass Energy Partners, LP ("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 and Dispositions*.

Merger Agreement with Tallgrass Energy Partners, LP

TGE previously entered into a definitive Agreement and Plan of Merger, dated as of March 26, 2018 (the "Merger Agreement"), with TEP, a Delaware limited partnership, Tallgrass MLP GP, LLC, a Delaware limited liability company and the general partner of TEP ("TEP GP"), and Razor Merger Sub, LLC, a Delaware limited liability company. The merger transaction contemplated by the Merger Agreement (the "TEP Merger") was completed effective June 30, 2018, and as a result, 47,693,097 TEP common units held by the public were converted into the right to receive Class A shares of TGE at an exchange ratio of 2.0 Class A shares for each outstanding TEP common unit, TEP's incentive distribution rights were cancelled, TEP's common units are no longer publicly traded, and 100% of TEP's equity interests are now owned by Tallgrass Equity and its subsidiaries. The TEP Merger was accounted for as an acquisition of noncontrolling interest. Following consummation of the TEP Merger, TGE changed its name from "Tallgrass Energy GP, LP" to "Tallgrass Energy, LP" and began trading on the New York Stock Exchange under the ticker symbol "TGE" on July 2, 2018.

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 and Dispositions*, we 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 Tallgrass Development's ("TD") 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 TGE include historical cost-basis accounts of the assets of Terminals and NatGas for the periods prior to January 1, 2017, the date we 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. TGE, 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 TGE at historical cost.

The consolidated financial statements include the accounts of TGE and its subsidiaries and controlled affiliates. Significant intra-entity items have been eliminated in the presentation. Net income or loss from consolidated subsidiaries that are not wholly-owned by TGE is attributed to TGE and noncontrolling interests in accordance with the respective ownership interests.

A variable interest entity ("VIE") is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has a variable interest that could be significant to the VIE and the power to direct the activities that most significantly impact the entity's economic performance. We have presented separately in our consolidated balance sheets, to the extent material, the liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit. Our consolidated VIEs did not have material assets that could only be used to settle specific obligations of the consolidated VIEs. Prior to June 29, 2018, both Tallgrass Equity and TEP were considered to be VIEs under the applicable authoritative guidance and included in our consolidated results. As a result of the TEP Merger, and changes in ownership and their respective partnership arrangements, Tallgrass Equity and TEP are no longer considered to be VIEs. We continue to consolidate our membership interests in Tallgrass Equity and TEP through the voting interest model.

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 $7.7 million and $0.5 million at December 31, 2018 and 2017, respectively.

Inventories

Inventories primarily consist of crude oil, materials and supplies, gas in underground storage, and natural gas liquids. 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 loss allowance oil, or PLA, which we can then sell. As PLA 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. Natural gas liquids and gas in underground storage, sometimes referred to as working gas, are recorded at the lower of historical cost and net realizable value using the average cost method. 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 $3.2 million and $2.6 million included in "Prepayments and other current assets" and "Deferred charges and other assets" in the consolidated balance sheets at December 31, 2018 and 2017, respectively. Regulatory assets at December 31, 2018 and December 31, 2017 were primarily attributable to costs associated with fuel tracker assets at our regulated natural gas pipelines as well as both Trailblazer's 2013 and 2018 Rate Case Filings and TIGT's 2015 Rate Case Filing. We recorded regulatory liabilities of approximately $1.9 million and $2.3 million included in "Other current liabilities" in the consolidated balance sheets at December 31, 2018 and 2017, 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 18 – *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. During 2018, we recognized additional intangible assets at Plaquemines Liquids Terminal, LLC ("PLT"), a newly formed subsidiary as discussed in Note 3 – *Acquisitions and Dispositions*, from the acquisition of permits, designs, and other work-product related to the development and construction of a crude oil terminal facility in Louisiana. These intangible assets will be amortized on a straight-line basis over a period of 35 years, the period of expected future benefit. Also, during 2018, we recognized an intangible asset associated with customer relationships as part of our acquisition of NGL Water Solutions Bakken, LLC as discussed in Note 3 – *Acquisitions and Dispositions*. The customer relationships are amortized on a straight-line basis over a period of 8 years. Other intangible assets include customer contracts amortized on a straight-line basis over a period of 2 - 14 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	2.9% - 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. Gas imbalances receivable and payable are included in "Prepayments and other current assets" and "Other current liabilities" in the consolidated balance sheets.

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. During the year ended December 31, 2018, we recognized a $2.2 million loss on debt retirement, recorded as "Other income, net" in the accompanying consolidated statements of income, associated with the write off of deferred financing costs associated with the Amendment to the TEP revolving credit facility and the termination of the Tallgrass Equity revolving credit facility as discussed further in Note 10 – *Long-term Debt.*

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. 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. 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 8 – *Goodwill and Other Intangible Assets* for additional information regarding impairment testing performed during 2018.

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 an 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 7 – *Investments in Unconsolidated Affiliates* for additional information regarding our investment in unconsolidated affiliates.

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.

Management 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 have not been 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 rates that vary throughout the term of the contract. 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 are accounted for as supply arrangements pursuant to ASC 705. As a result, gathering & processing fees previously recognized in revenue are reported as a reduction to cost of sales under ASC 606.
- *Pipeline Loss Allowance.* We have determined that 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 Pony Express. Under ASC 606, PLA barrels retained from customers are subject to the guidance for noncash consideration and recognized in revenue at their contract inception fair value.

See Note 12 – *Revenue from Contracts with Customers* for revenue disclosures related to both the implementation and 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.

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

Our operations expose us to a variety of risks including, but not limited to, changes in the prices of commodities that we buy or sell. We manage these exposures with either physical or financial transactions. We have established a comprehensive risk management policy and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. The Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including establishing and monitoring exposure limits.

We record derivative contracts at their estimated fair values as of each reporting date and present profit and loss activity on a net basis in "Processing and other revenues" in our consolidated statements of operations. 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 16 – *Equity-Based Compensation*, prior to February 2018 a portion of the expense recognized relating to equity-based compensation grants was charged to TD.

Income Taxes

Although TGE is organized as a limited partnership, we have elected to be treated as a corporation for U.S. federal income tax purposes and are therefore subject to both U.S. federal and state income taxes. TGE's consolidated subsidiaries consist primarily of entities that are flow-through entities for income tax purposes. We also own certain C corporation subsidiaries which have been formed for the purpose of potential pipeline construction and other investment purposes. In addition, Tallgrass Energy Finance Corp. is a wholly owned subsidiary of TEP that has no material assets and was formed for the sole purpose of being a co-issuer of TEP's senior notes as discussed in Note 10 – *Long-term Debt*. These C corporation subsidiaries have not commenced operations or generated any material income, and as a result no provision for federal or state income taxes has been recorded in our consolidated financial statements.

Deferred income taxes are provided for temporary differences arising from differences between the consolidated financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates expected to be in effect when the related taxes are expected to be paid or recovered. A valuation allowance is established if it is more likely than not that a deferred tax asset will not be realized. In determining the appropriate valuation allowance, we consider projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies, and our overall deferred tax position.

Pursuant to the applicable guidance related to accounting for uncertainty in income taxes, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the tax position and also the past administrative practices and precedents of the taxing authority. As of December 31, 2018, we had not recognized any material amounts in connection with uncertainty in income taxes.

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 or complex 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 approach may be utilized to estimate the fair value of the assets acquired, liabilities assumed, and noncontrolling interest, if any, in a business combination. We typically use an income approach, such as the multi-period excess earnings method, to value intangible assets. The income approach requires management to estimate future cash flows: (i) discrete financial forecasts, which rely on management's estimates of gross margin and operating expenses; (ii) terminal growth rates; and (iii) appropriate discount rates. We typically use a cost approach to value property, plant and equipment. The cost approach 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 and Dispositions* for additional information regarding our business combinations.

Accounting Pronouncements Not Yet Adopted

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 right-of-use ("ROU") 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.

Subsequent to issuing ASU 2016-02, the FASB has issued a series of subsequent updates to the lease guidance in Topic 842, including ASU No. 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842, ASU No. 2018-10, Codification Improvements to Topic 842, Leases, ASU No. 2018-11, Leases (Topic 842): Targeted Improvements, and ASU 2018-20, Leases (Topic 842): Narrow-Scope Improvements for Lessors. The amendments in ASU 2016-02, ASU

2018-01, ASU 2018-10, ASU 2018-11, and ASU 2018-20 are effective for public entities for annual reporting periods beginning after December 15, 2018, 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, 2019. The approach allows us to (i) initially apply ASC 842 at the adoption date, January 1, 2019 and (ii) continue reporting comparative periods presented in the financial statements in the period of adoption under ASC 840. We will not recast comparative periods in the consolidated financial statements. We have elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allowed us to carry forward the historical lease classification. We also elected the practical expedient related to land easements, allowing us to carry forward our accounting treatment for land easements on existing agreements as property, plant and equipment.

Adoption of the new standard resulted in the recognition of ROU assets and lease liabilities for operating leases as of January 1, 2019. Excluding ROU assets and lease liabilities relating to agreements between consolidated subsidiaries, the ROU assets and liabilities recognized as of January 1, 2019 are not expected to be material. Our accounting for finance leases remained substantially unchanged.

3. Acquisitions and Dispositions

Consolidation of BNN Colorado

Effective December 1, 2018, we obtained control of BNN Colorado Water, LLC ("BNN Colorado") through an amendment to the voting rights in BNN Colorado's limited liability company agreement. Prior to the amendment, we accounted for our interest in BNN Colorado under the equity method of accounting. The consolidation was accounted for as a business combination under ASC 805. No gain or loss was recognized on the remeasurement of our 63% membership interest as of December 1, 2018, as the carrying value was determined to approximate the fair value. The 37% equity interest in BNN Colorado held by noncontrolling interests was recorded at its acquisition date fair value of $10.1 million. 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 (in thousands):

Accounts receivable	$	4,053
Property, plant and equipment		18,535
Intangible asset		7,922 [(1)]
Accounts payable and accrued liabilities		(53)
Deferred revenue		(4,053)
Net identifiable assets acquired (excluding cash)	$	26,404

(1) The $7.9 million intangible asset acquired represents a customer contract. This intangible asset is amortized on a straight-line basis over a period of approximately 3 years, the remaining term of the underlying contract at the time of acquisition.

At December 31, 2018, the assets acquired and liabilities assumed were recorded at provisional amounts based on the preliminary purchase price allocation. We are in the process of identifying and measuring all assets acquired and liabilities assumed in the acquisition within the measurement period. Such provisional amounts will be adjusted if necessary to reflect any new information about facts and circumstances that existed at the acquisition date that, if known, would have affected the measurement of these amounts. Actual revenue and net loss attributable to TGE from BNN Colorado of less than $1.0 million was recognized in the accompanying consolidated statements of income for the period from December 1, 2018 to December 31, 2018.

Acquisitions of BNN North Dakota

In January 2018, we acquired 100% of the membership interests in Buckhorn Energy Services, LLC and Buckhorn SWD Solutions, LLC, which were subsequently merged and renamed BNN North Dakota, LLC ("BNN North Dakota"), for approximately $95.0 million, net of cash acquired. BNN North Dakota owns a produced water gathering and disposal system in the Bakken basin with approximately 133,000 acres under dedication. 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 (in thousands):

Accounts receivable	$	2,457
Inventory		67
Property, plant and equipment		48,900
Intangible asset		46,800 (1)
Accounts payable and accrued liabilities		(3,224)
Net identifiable assets acquired (excluding cash)	$	95,000

(1) The $46.8 million intangible asset acquired represents three major customer contracts. This intangible asset is amortized on a straight-line basis over a period of 8 - 14 years, the remaining terms of the underlying contracts at the time of acquisition.

At March 31, 2018, 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 June 30, 2018. Actual revenue and net income attributable to TGE from BNN North Dakota of $18.8 million and $4.7 million, respectively, was recognized in the accompanying consolidated statements of income for the period from January 12, 2018 to December 31, 2018.

In November 2018, we acquired 100% of the membership interests in NGL Water Solutions Bakken, LLC ("NGL Water Solutions Bakken"), a produced water disposal system in the Bakken basin, for cash consideration of approximately $91.0 million, subject to working capital adjustments. NGL Water Solutions Bakken was subsequently merged into BNN North Dakota. 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 (in thousands):

Accounts receivable	$	3,599
Prepayments and other current assets		5
Property, plant and equipment		17,200
Intangible asset		54,000 (1)
Accounts payable and accrued liabilities		(949)
Net identifiable assets acquired		73,855
Goodwill		17,145
Net assets acquired	$	91,000

(1) The $54.0 million intangible asset acquired represents customer relationships and a customer contract. This intangible asset is amortized on a straight-line basis over a period of 3 - 8 years.

At December 31, 2018, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. We are in the process of identifying and measuring all assets acquired and liabilities assumed in the acquisition within the measurement period. Such provisional amounts will be adjusted if necessary to reflect any new information about facts and circumstances that existed at the acquisition date that, if known, would have affected the measurement of these amounts. The goodwill recognized of $17.1 million is primarily attributed to synergies expected from combining the operations of TGE and NGL Water Solutions Bakken. All the goodwill was assigned to our Gathering, Processing & Terminalling segment. Actual revenue and net income attributable to TGE from NGL Water Solutions Bakken of $1.4 million and $0.5 million, respectively, was recognized in the accompanying consolidated statements of income for the period from November 30, 2018 to December 31, 2018.

Acquisition of Plaquemines Liquids Terminal, LLC

In November 2018, we entered into a joint venture agreement with Drexel Hamilton Infrastructure Fund I, L.P. ("DHIF") to jointly-own Plaquemines Liquids Terminal, LLC ("PLT"). PLT was formed with the intention of entering into agreements to develop a storage and terminalling facility. The facility is expected to offer up to 20 million barrels of storage for both crude oil and refined products and export facilities capable of loading Suezmax and Very Large Crude Carriers ("VLCC") vessels for international delivery. We made an initial cash contribution to PLT of $30.7 million in exchange for a 100% preferred membership interest and a 80% common membership interest in PLT. DHIF contributed any and all assets and rights related to PLT in exchange for a 20% common membership interest and the right to receive certain special distributions. Our preferred and common membership interests are considered to be a controlling financial interest and PLT was consolidated accordingly. The transaction has been accounted for as an asset acquisition, with substantially all the fair value allocated to the assets and liabilities acquired based on their relative fair values. The intangible assets acquired, valued at approximately $35 million, relate to permits, designs, and other work-product related to the development and construction of a crude oil terminal facility in Louisiana. The liabilities recognized relate to DHIF's right to receive special distributions totaling $35 million. The special distributions are contingent upon PLT reaching certain milestones in the development and construction of the project facilities. Also in November 2018, PLT entered into an agreement with the Plaquemines Port & Harbor Terminal District to lease the land site on which PLT will construct the facilities.

Acquisition of Pawnee Terminal

In January 2018, we 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 $30.6 million. The transaction closed on April 1, 2018. As the 51% membership interest does not represent a controlling interest in Pawnee, our investment in Pawnee Terminal is recorded under the equity method of accounting and reported as "Unconsolidated investments" on the consolidated balance sheets.

Acquisitions of 75% Membership Interest in Rockies Express and Additional TEP Common Units

In May 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.

In March 2017, TEP, TD, and Rockies Express Holdings, LLC, 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.

The 2017 transfer of the Rockies Express membership interest between TD and TEP 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 acquisition resulted in the recognition of a noncash deemed contribution representing the excess carrying value of the 24.99% membership interest in Rockies Express acquired over the fair value of the consideration paid. For further discussion, see Note 11 - *Partnership Equity*.

In February 2018, TD merged into Tallgrass Development Holdings, LLC, a wholly-owned subsidiary of Tallgrass Equity ("Tallgrass Development Holdings"), and as a result of the merger, Tallgrass Equity acquired a 25.01% membership interest in Rockies Express and an additional 5,619,218 TEP common units. As consideration for the acquisition, TGE and Tallgrass Equity issued 27,554,785 unregistered TGE Class B shares and Tallgrass Equity units, valued at approximately $644.8 million based on the closing price on February 6, 2018, to the limited partners of TD. Subsequent to the closing of the transaction, our aggregate membership interest in Rockies Express is 75%.

The 2018 transfer of the Rockies Express membership interest between TD and Tallgrass Equity 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 acquisition resulted in the recognition of a noncash deemed contribution representing the excess carrying value of the 25.01% membership interest in Rockies Express acquired over the fair value of the consideration paid. For further discussion, see Note 11 - *Partnership Equity*. As the aggregate 75% membership interest does not represent a controlling interest in Rockies Express, TGE's investment in Rockies Express is recorded under the equity method of accounting and is reported as "Unconsolidated investments" on our consolidated balance sheets. For additional information, see Note 7 - *Investments in Unconsolidated Affiliates.*

The acquisition of an additional 5,619,218 TEP common units is considered an acquisition of noncontrolling interest and resulted in the recognition of a noncash deemed distribution representing the excess purchase price over the $53.8 million carrying value of the 5,619,218 TEP common units acquired as of February 7, 2018. For further discussion, see Note 11 - *Partnership Equity*.

Acquisition and Sale of Outrigger Powder River Operating, LLC

In August 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 (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 TGE 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.

In February 2018, we entered into an agreement with an affiliate of Silver Creek Midstream, LLC ("Silver Creek") to sell our 100% membership interest in TCG, for approximately $50.0 million. The sale of TCG closed on February 23, 2018. During the year ended December 31, 2018, we recognized a gain of $9.4 million on the sale which is presented in the line item "Gain on disposal of assets" in the consolidated statements of income.

Joint Venture with Silver Creek

In February 2018, we entered into an agreement with Silver Creek to form Iron Horse Pipeline, LLC ("Iron Horse"), which owns a new 80-mile crude oil pipeline currently under construction that will transport crude oil from the Powder River Basin to Guernsey, Wyoming ("Iron Horse Pipeline"). During the year ended December 31, 2018, we contributed an initial $3.5 million and committed to funding our proportionate share of the remaining costs of construction in exchange for a 75% membership interest in Iron Horse. As the 75% membership interest does not represent a controlling interest in Iron Horse, our investment in Iron Horse is accounted for under the equity method of accounting and reported as "Unconsolidated investments" on the consolidated balance sheets.

In August 2018, we entered into an agreement with Silver Creek to expand the Iron Horse joint venture through the contribution by us and Silver Creek of cash and additional Powder River Basin assets. These additional contributions closed in January 2019. We contributed our 75% membership interest in Iron Horse, $37 million in cash, and various other assets, including terminal facilities currently under construction in Guernsey, Wyoming. Silver Creek contributed the Powder River Express Pipeline ("PRE Pipeline") and their 25% membership interest in Iron Horse. The expanded joint venture operates under the name Powder River Gateway, LLC ("Powder River Gateway"), and owns the Iron Horse Pipeline, the PRE Pipeline, a 70-mile crude oil pipeline that transports crude oil from the Powder River Basin to Guernsey, Wyoming, and crude oil terminal facilities in Guernsey, Wyoming. Effective January 1, 2019, we own a 51% membership interest in Powder River Gateway and continue to operate the joint venture, while Silver Creek owns a 49% membership interest.

Acquisitions of Additional Interests in Deeprock Development, LLC

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") 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, we remeasured our 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 (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 our operations with the operations of Deeprock Development. All the goodwill was assigned to our Gathering, Processing & Terminalling segment. Actual revenue and net income attributable to TGE from Deeprock Development of $10.5 million and $0.9 million, respectively, was recognized in the accompanying consolidated statements of income for the period from July 20, 2017 to December 31, 2017.

In July 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 TEP 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 Deeprock North and Merger with Deeprock Development

In January 2018, we 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, and the members of Deeprock North and Deeprock Development received adjusted membership interests in the combined entity. As a result, we recognized additional noncontrolling interests in Deeprock Development of $31.8 million. The acquisition of Deeprock North by Deeprock Development has been accounted for as an asset acquisition, with substantially all of the fair value allocated to the long-lived assets acquired based on their relative fair values. After the acquisition and merger, we own an approximate 60% membership interest in the combined entity.

Acquisition of DCP Douglas, LLC

In June 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. 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.

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

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 TD for total cash consideration of $140 million. These acquisitions are considered transactions between entities under common control, and a change in reporting entity. As a result of the common control nature of the transaction, the acquisitions resulted in the recognition of a noncash deemed distribution representing the excess fair value of the consideration paid over the carrying value of Terminals and NatGas net assets acquired. For further discussion, see Note 11 - *Partnership Equity*.

Acquisitions of Pony Express

In January 2016, we 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% effective January 1, 2016. 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. In February 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, we 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 9 – *Risk Management*.

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. As a result of the common control nature of the transaction, the acquisition resulted in the recognition of a noncash deemed distribution representing the excess fair value of the consideration paid over the carrying value of the 31.3% membership interest in Pony Express acquired. For further discussion, see Note 11 - *Partnership Equity*.

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.

In February 2018, we acquired the remaining 2% membership interest in Pony Express, along with administrative assets consisting primarily of information technology assets, from TD for cash consideration of approximately $60 million, bringing our aggregate membership interest in Pony Express to 100%. The acquisition of the remaining 2% 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 2% membership interest. As a result of the common control nature of the transaction, the acquisition resulted in the recognition of a noncash deemed distribution representing the excess fair value of the consideration paid over the carrying value of the 2% membership interest in Pony Express acquired. For further discussion, see Note 11 – *Partnership Equity*.

Pro Forma Financial Information

Unaudited pro forma revenue and net income (loss) attributable to TGE for the years ended December 31, 2018 and 2017 is presented below as if the acquisitions of BNN North Dakota, NGL Water Solutions Bakken, and BNN Colorado had been completed on January 1, 2017. Unaudited pro forma revenue and net (loss) income attributable to TGE 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.

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Revenue	$ 813,286	$ 686,803	$ 632,528
Net income (loss) attributable to TGE	$ 140,005	$ (129,155)	$ 34,311

The pro forma financial information is not necessarily indicative of what the actual results of operations or financial position of TGE 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 TGE 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 (loss) includes adjustments to give effect to the estimated results of operations of BNN North Dakota, NGL Water Solutions Bakken, BNN Colorado, TCG, and Deeprock Development for the periods presented. The pro forma net income (loss) also includes adjustments to eliminate the equity in earnings and gain on remeasurement of unconsolidated investment associated with our previously held 20% membership interest in Deeprock Development and to eliminate the equity in earnings associated with our 63% membership interest in BNN Colorado which was previously accounted for as an equity method investment.

Historical Financial Information

The results of our acquisitions of Terminals and NatGas are included in the consolidated balance sheets as of December 31, 2018 and December 31, 2017 and in the consolidated statements of income for the years ended December 31, 2018, 2017, and 2016. The following table presents the previously reported consolidated statements of income for the year ended December 31, 2016 adjusted for the acquisitions of Terminals and NatGas:

	Year Ended December 31, 2016				
	TGE (As previously reported)	Consolidate Terminals	Consolidate NatGas	Elimination	TGE (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	55,829	1,469	—	—	57,298
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	350,948	14,126	—	(11,830)	353,244
Operating Income (Expense)	254,174	(1,984)	6,228	—	258,418
Other Income (Expense):					
Equity in earnings of unconsolidated investments	51,780	2,751	—	—	54,531
Interest expense, net	(45,601)	—	—	—	(45,601)
Other income, net	432	—	—	—	432
Total Other Income	6,611	2,751	—	—	9,362
Net income before tax	260,785	767	6,228	—	267,780
Deferred income tax expense	(17,741)	—	—	—	(17,741)
Net income	243,044	767	6,228	—	250,039
Net income attributable to noncontrolling interests	(216,250)	—	—	—	(216,250)
Net income attributable to TGE	$ 26,794	$ 767	$ 6,228	$ —	$ 33,789

(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, LLC ("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.

All of our employees are employed by Tallgrass Management, LLC ("Tallgrass Management"). Prior to July 1, 2018, Tallgrass Management was a wholly-owned subsidiary of Tallgrass Energy Holdings. In connection with the closing of the TEP initial public offering on May 17, 2013, TEP and TEP GP 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. In addition, in connection with the closing of the TGE initial public offering on May 12, 2015 (the "TGE IPO"), TGE entered into an Omnibus Agreement (the "TGE Omnibus Agreement") with Tallgrass Energy GP, LLC (formerly known as TEGP Management, LLC), Tallgrass Equity and Tallgrass Energy Holdings.

Effective July 1, 2018, Tallgrass Management was contributed to Tallgrass Equity in connection with the TEP Merger. As a result, the costs of employer and director compensation and benefits are now incurred directly by Tallgrass Equity.

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

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Processing and other revenues [(1)]	$ 7,483	$ 8,516	$ 6,228
Cost of transportation services [(2)]	$ —	$ 10,476	$ 18,585
Charges to TGE: [(3)]			
Property, plant and equipment, net	$ —	$ 2,679	$ 3,084
Other deferred charges	$ —	$ 25	$ 44
Operations and maintenance	$ —	$ 29,881	$ 25,431
General and administrative	$ —	$ 41,676	$ 40,321

(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 and Dispositions.*

(3) Charges to TGE, inclusive of Tallgrass Equity and TEP, include indirectly charged wages and salaries, other compensation and benefits, and shared services for periods prior to January 1, 2018. Effective January 1, 2018, these costs are incurred by TEP directly and, in the case of certain employee compensation and benefits, paid on TEP's behalf by its affiliate, Tallgrass Management, LLC, pursuant to the TEP Omnibus Agreement.

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

	December 31, 2018	December 31, 2017
	(in thousands)	
Receivable from related parties:		
Rockies Express Pipeline LLC	$ 3,447	$ 1,340
Iron Horse Pipeline, LLC	186	—
Pawnee Terminal, LLC	115	—
Total receivable from related parties	$ 3,748	$ 1,340
Accounts payable to related parties:		
Tallgrass Operations, LLC [(1)]	$ —	$ 5,342
Total accounts payable to related parties	$ —	$ 5,342

(1) Reflects accounts payable for charges to TGE, inclusive of Tallgrass Equity and TEP, including indirectly charged wages and salaries, other compensation and benefits, and shared services prior to January 1, 2018 as discussed above.

Gas imbalances with affiliated shippers are as follows:

	December 31, 2018	December 31, 2017
	(in thousands)	
Affiliate gas imbalance receivables	$ 19	$ 18
Affiliate gas imbalance payables	$ 742	$ 442

5. Inventory

The components of inventory at December 31, 2018 and 2017 consisted of the following:

	December 31, 2018	December 31, 2017
	(in thousands)	
Crude oil	$ 23,205	$ 12,792
Materials and supplies	8,206	5,891
Gas in underground storage	2,740	1,984
Natural gas liquids	165	942
Total inventory	$ 34,316	$ 21,609

6. Property, Plant and Equipment

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

	December 31, 2018	December 31, 2017
	(in thousands)	
Crude oil pipelines	$ 1,313,976	$ 1,220,379
Gathering, processing and terminalling assets [(1)]	889,168	675,092
Natural gas pipelines	607,343	581,400
General and other [(2)]	180,299	98,680
Construction work in progress	191,994	97,978
Accumulated depreciation and amortization	(380,351)	(279,192)
Total property, plant and equipment, net [(3)]	$ 2,802,429	$ 2,394,337

(1) Includes approximately $53.6 million and $46.2 million of assets associated with the acquisitions of BNN North Dakota in January and November 2018 and Deeprock North in January 2018, respectively.

(2) Includes approximately $30.7 million of land associated with the PLT capital lease as discussed in Note 3 – *Acquisitions and Dispositions*.

(3) Property, plant and equipment, net includes approximately $455.8 million of assets at our regulated natural gas pipelines at December 31, 2018.

Depreciation expense was approximately $102.7 million, $86.9 million, and $83.2 million for the years ended December 31, 2018, 2017, and 2016, respectively. Capitalized interest was approximately $5.2 million, $1.1 million, and $0.6 million for the years ended December 31, 2018, 2017, and 2016, respectively.

Under various lease agreements, TMID, as lessor, leases capacity on NGL pipelines that were constructed for third parties, and Deeprock Development, as lessor, leases capacity on certain of its storage facilities under lease agreements acquired as part of the Deeprock North acquisition on January 2, 2018. Rental income for these arrangements was approximately $10.9 million, $3.8 million, and $3.2 million for the years ended December 31, 2018, 2017, and 2016, 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, 2018, 2017, and 2016 and was recorded as "Other income, net" in the accompanying consolidated statements of income.

As of December 31, 2018, future minimum rental income under non-cancelable operating leases as the lessor were as follows (in thousands):

Year	Total
2019	$ 7,742
2020	3,952
2021	3,773
2022	3,773
2023	3,773
Thereafter	7,353
Total	$ 30,366

7. 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 and Dispositions*, we acquired an additional 24.99% and 25.01% membership interest in Rockies Express from TD on March 31, 2017 and February 7, 2018, respectively. 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. As of February 7, 2018, the negative basis difference carried over from TD from the transfer of the 25.01% Rockies Express membership interest was approximately $376.5 million. The transfer of the 24.99% Rockies Express membership interest between TD and TEP and the 25.01% Rockies Express membership interest between TD and Tallgrass Equity are considered transactions between entities under common control, but does not represent a change in reporting entity. As a result of the common control nature of the transactions, the 24.99% and 25.01% membership interests in Rockies Express were transferred to TEP and Tallgrass Equity, respectively, at TD's historical carrying amount, including the remaining unamortized basis difference driven by the difference between the fair value of the investments and the book value of the underlying assets and liabilities on November 13, 2012, the date of acquisition by TD.

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, 2018, the basis difference for our membership interests in Rockies Express was allocated as follows:

	Basis Difference	Amortization Period
	(in thousands)	
Long-term debt	$ 47,182	2 - 25 years
Property, plant and equipment	(1,146,984)	35 years
Total basis difference	$ (1,099,802)	

During the year ended December 31, 2018, we recognized equity in earnings associated with our aggregate 75% membership interest in Rockies Express of $303.4 million, inclusive of the amortization of the negative basis difference, and received distributions from and made contributions to Rockies Express of $380.7 million and $432.0 million, respectively.

In July 2018, we made a special contribution of approximately $412.5 million to fund our portion of the repayment of Rockies Express' $550 million of 6.85% senior notes due July 15, 2018.

BNN Colorado Water, LLC

As discussed in Note 3 – *Acquisitions and Dispositions*, we consolidated BNN Colorado effective December 1, 2018 and no longer account for our investment in BNN Colorado under the equity method of accounting.

Deeprock Development

As discussed in Note 3 – *Acquisitions and Dispositions,* on July 20, 2017, we acquired an additional 40% membership interest in Deeprock Development. As a result of the acquisition, we consolidated Deeprock Development and effective July 20, 2017 we no longer account for our 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, 2016 to July 20, 2017, the date we 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, 2018. Summarized financial information for BNN Colorado is presented from the date of the acquisition, June 23, 2017 to December 1, 2018, the date we acquired a controlling interest in BNN Colorado. Summarized financial information for Iron Horse is presented from the date of the acquisition, February 23, 2018 to December 31, 2018. Summarized financial information for Pawnee Terminal is presented from the date of the acquisition, April 1, 2018 to December 31, 2018.

	December 31, 2018	December 31, 2017
	(in thousands)	
Current assets	$ 132,213	$ 122,362
Noncurrent assets	$ 6,031,066	$ 5,974,926
Current liabilities	$ 694,951	$ 714,037
Noncurrent liabilities	$ 1,502,906	$ 2,049,189
Members' equity	$ 3,965,422	$ 3,334,062

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Revenue	$ 930,771	$ 860,115	$ 440,838
Operating income	$ 524,607	$ 480,337	$ 203,801
Net income to Members	$ 376,934	$ 465,592	$ 184,314

8. Goodwill and Other Intangible Assets

Reconciliation of Goodwill

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

	Year Ended December 31, 2018			Year Ended December 31, 2017		
	Natural Gas Transportation	Gathering, Processing & Terminalling	Total	Natural Gas Transportation	Gathering, Processing & Terminalling	Total
			(in thousands)			
Balance at beginning of period	$ 255,558	$ 149,280	$ 404,838	$ 255,558	$ 87,730	$ 343,288
Goodwill acquired	—	17,145 [(1)]	17,145	—	61,550 [(2)]	61,550
Balance at end of period	$ 255,558	$ 166,425	$ 421,983	$ 255,558	$ 149,280	$ 404,838

(1) The $17.1 million of goodwill was recorded in connection with the acquisition of NGL Water Solutions Bakken on November 30, 2018 as discussed further in Note 3 – *Acquisitions and Dispositions*.

(2) 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 and Dispositions*.

Annual Goodwill Impairment Analysis

In 2018, we elected to apply the qualitative assessment option for four of our five reporting units. In conducting the qualitative assessment we considered relevant factors and circumstances that affect the fair value or carrying amount of the reporting entity. Such factors included changes in discount rates, projected cash flows, macroeconomic considerations, industry and market considerations, overall financial performance, prior quantitative results, and entity and reporting unit specific events. For each of these reporting units, the results of the qualitative assessment indicated that it was more likely than not that the fair value of the reporting units exceeded their respective book values. As such, we did not perform a quantitative impairment analysis, and we concluded that no impairment was indicated as of August 31, 2018.

We did not elect to apply the qualitative assessment option for one reporting unit during our 2018 annual goodwill impairment testing; instead we proceeded directly to the quantitative impairment test. We compared the fair value of the reporting unit with its respective book value, including goodwill, by using an income approach based on a discounted cash flow analysis. The fair value of the 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 revenue, operating expenses, general and administrative expenses, terminal growth rates, maintenance capital expenditures, and the weighted average cost of capital. The fair value of the reporting unit was determined using significant unobservable inputs, considered Level 3 under the fair value hierarchy in the Codification. For this reporting unit, the results of the quantitative impairment test indicated no impairment as the fair value of the reporting unit was greater than its respective book value. As a result, in accordance with the Codification guidance, we did not record a goodwill impairment during the year ended December 31, 2018. Unpredictable events or deteriorating market or operating conditions could result in a future change to the discounted cash flow model 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, 2018	December 31, 2017
	(in thousands)	
Pony Express oil conversion use rights	$ 105,973	$ 105,973
Customer contracts	60,348	8,064
Customer relationships	52,100	—
Plaquemines Liquids Terminal use rights and permits	35,000	—
Accumulated amortization	(26,318)	(16,306)
Intangible assets, net	$ 227,103	$ 97,731

Amortization of intangible assets was approximately $8.1 million, $3.8 million, and $3.0 million for the years ended December 31, 2018, 2017, and 2016, respectively.

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

Year	Total
2019	$ 16,528
2020	16,347
2021	16,294
2022	13,144
2023	13,144
Thereafter	116,646
Total [1]	$ 192,103

(1) Excludes the $35 million intangible asset at PLT, as discussed in Note 3 – *Acquisitions and Dispositions,* that will be amortized over 35 years beginning on the in-service date of the project facilities.

9. Risk Management

We enter into derivative contracts with third parties for the purpose of hedging exposures that accompany our normal business activities. We also engage in the business of trading energy related products and services, which exposes us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments.

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, 2018	December 31, 2017
		(in thousands)	
Crude oil derivative contracts [1]	Prepayments and other current assets	$ 3,526	$ —
Crude oil derivative contracts [2]	Other current liabilities	$ 1,642	$ 2,368

(1) As of December 31, 2018, the fair value shown for crude oil derivative contracts represents the forward purchase of 2,105,146 barrels of crude oil, consisting of fixed price and floating price contracts, which will settle throughout 2019.

(2) As of December 31, 2018, the fair value shown for crude oil derivative contracts represents the forward sale of 1,274,500 barrels of crude oil, consisting of fixed price and floating price contracts, which will settle throughout the first quarter of 2019. As of December 31, 2017, the fair value shown for crude oil derivative contracts represents the forward sale of 356,000 barrels of crude oil, consisting of fixed price and floating price contracts, which settled in the first quarter of 2018.

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, 2018, 2017 and 2016:

	Location of gain (loss) recognized in income on derivatives	Amount of gain (loss) recognized in income on derivatives		
		Year Ended December 31,		
		2018	2017	2016
			(in thousands)	
Crude oil derivative contracts	Sales of natural gas, NGLs, and crude oil	$ 29,510	$ 39	$ (40)
Natural gas derivative contracts	Sales of natural gas, NGLs, and crude oil	$ —	$ 75	$ 74
Call option derivative	Other income, net	$ —	$ 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 TEP an 18 month call option at an exercise price of $42.50 per TEP common unit covering the 6,518,000 TEP common units issued to TD as a portion of the consideration. In July 2016 and October 2016, TEP 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, TEP 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. The maximum potential exposure to credit losses on our crude oil derivative contracts at December 31, 2018 was:

	Asset Position
	(in thousands)
Gross	$ 3,526
Netting agreement impact	—
Cash collateral held	—
Net exposure	$ 3,526

As of December 31, 2018, we did not have any cash in margin accounts or outstanding letters of credit in support of our commodity derivatives. 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.

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 following table summarizes the fair value measurements of our derivative contracts as of December 31, 2018 and 2017, 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, 2018:				
Crude oil derivative contracts	$ 3,526	$ —	$ 3,526	$ —

		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, 2018:				
Crude oil derivative contracts	$ 1,642	$ —	$ 1,642	$ —
As of December 31, 2017:				
Crude oil derivative contracts	$ 2,368	$ —	$ 2,368	$ —

10. Long-term Debt

Long-term debt consisted of the following at December 31, 2018 and 2017:

	December 31, 2018	December 31, 2017
	(in thousands)	
Tallgrass Equity revolving credit facility [(1)]	$ —	$ 146,000
TEP revolving credit facility	1,224,000	661,000
TEP 4.75% senior notes due October 1, 2023	500,000	—
TEP 5.50% senior notes due September 15, 2024	750,000	750,000
TEP 5.50% senior notes due January 15, 2028	750,000	750,000
Less: Deferred financing costs, net [(2)]	(21,421)	(17,737)
Plus: Unamortized premium on 2028 Notes	3,379	3,730
Total long-term debt, net	$ 3,205,958	$ 2,292,993

(1) On July 26, 2018, Tallgrass Equity repaid all outstanding borrowings and terminated its revolving credit facility.

(2) Deferred financing costs, net as presented above relate solely to the Senior Notes (as defined below). Deferred financing costs associated with our revolving credit facilities are presented in noncurrent assets on our consolidated balance sheets.

TEP Senior Unsecured Notes

On September 26, 2018, 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 26, 2018 (the "2023 Indenture") pursuant to which the Issuers issued $500 million in aggregate principal amount of 4.75% senior notes due 2023 (the "2023 Notes").

The 2023 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.

The Issuers have also previously issued $500 million in aggregate principal amount of 5.50% senior notes due 2028 (the "2028 Notes") on September 15, 2017 and an additional $250 million in aggregate principal amount of the 2028 Notes on December 11, 2017. The 2028 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 and offering price. The 2028 Notes are governed by an Indenture dated September 15, 2017 (the "2028 Indenture") which 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.

In addition, the Issuers have previously issued $400 million in aggregate principal amount of 5.50% senior notes due 2024 (the "2024 Notes") on September 1, 2016 and an additional $350 million in aggregate principal amount of the 2024 Notes on May 16, 2017. The 2024 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 Notes are governed by an Indenture dated September 1, 2016 (the "2024 Indenture") which 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.

The 2023 Notes, 2024 Notes, and 2028 Notes are together referred to as the "Senior Notes." As of December 31, 2018, TEP was in compliance with the covenants required under the 2023 Indenture, the 2024 Indenture, and the 2028 Indenture.

TEP Revolving Credit Facility

The following table sets forth the available borrowing capacity under the TEP revolving credit facility as of December 31, 2018 and 2017:

	December 31, 2018	December 31, 2017
	(in thousands)	
Total capacity under the TEP revolving credit facility	$ 2,250,000	$ 1,750,000
Less: Outstanding borrowings under the TEP revolving credit facility	(1,224,000)	(661,000)
Less: Letters of credit issued under the TEP revolving credit facility	(94)	(94)
Available capacity under the TEP revolving credit facility	$ 1,025,906	$ 1,088,906

On July 26, 2018, TEP and certain of its subsidiaries entered into Amendment No. 1 (the "Amendment") to its existing revolving credit facility with Wells Fargo Bank, National Association, as administrative agent and collateral agent, and a syndicate of lenders (the "Credit Agreement"). The Amendment modified certain provisions of the Credit Agreement to, among other things, (i) increase the available amount of the TEP revolving credit facility to $2.25 billion, (ii) reduce certain applicable margins in the pricing grids used to determine the interest rate and revolving credit commitment fees, (iii) modify the use of proceeds to allow TEP to pay off the Tallgrass Equity revolving credit facility, and (iv) increase the maximum total leverage ratio to 5.50 to 1.00.

TEP's revolving credit facility contains various covenants and restrictive provisions that, among other things, limit or restrict TEP's ability (as well as the ability of its 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 its 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, TEP is required to maintain a consolidated leverage ratio of not more than 5.50 to 1.00 (5.00 to 1.00 prior to the Amendment), 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, 2018, TEP was in compliance with the covenants required under its revolving credit facility. The consummation of the Blackstone Acquisition would constitute an event of default under TEP's revolving credit agreement. The closing conditions of the Blackstone Acquisition include TEP obtaining the consent or waiver of the required lenders under TEP's revolving credit facility in connection with the transactions contemplated by the Blackstone Acquisition.

The unused portion of TEP's revolving credit facility is subject to a commitment fee, which ranges from 0.250% to 0.375% (0.250% to 0.500% prior to the Amendment), based on TEP's total leverage ratio. As of December 31, 2018, the weighted average interest rate on outstanding borrowings under the TEP revolving credit facility was 3.96%. During the year ended December 31, 2018, the weighted average effective interest rate under the TEP revolving credit facility, including the interest on outstanding borrowings under TEP's revolving credit facility, commitment fees, and amortization of deferred financing costs, was 4.11%.

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, 2018 and 2017, 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, 2018:					
Revolving credit facility	$ —	$ 1,224,000	$ —	$ 1,224,000	$ 1,224,000
2023 Notes	$ —	$ 485,285	$ —	$ 485,285	$ 494,603
2024 Notes	$ —	$ 737,745	$ —	$ 737,745	$ 741,196
2028 Notes	$ —	$ 726,503	$ —	$ 726,503	$ 746,159
As of December 31, 2017:					
Revolving credit facilities	$ —	$ 807,000	$ —	$ 807,000	$ 807,000
2024 Notes	$ —	$ 771,645	$ —	$ 771,645	$ 739,824
2028 Notes	$ —	$ 758,168	$ —	$ 758,168	$ 746,169

The long-term debt borrowed under the revolving credit facilities is carried at amortized cost. As of December 31, 2018 and 2017, the fair value of borrowings under the revolving credit facilities approximates the carrying amount of the borrowings using a discounted cash flow analysis. The Senior Notes are carried at amortized cost, net of deferred financing costs. The estimated fair value of the Senior 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, 2018.

11. Partnership Equity

TGE Dividends to Holders of Class A Shares

The following table details the dividends for the periods indicated:

Three Months Ended	Date Paid	Dividends to Class A Shareholders	Dividends per Class A Share
December 31, 2018	February 14, 2019 [(1)]	$ 81,304	$ 0.5200
September 30, 2018	November 14, 2018	79,717	0.5100
June 30, 2018	August 14, 2018	77,052	0.4975
March 31, 2018	May 15, 2018	28,316	0.4875
December 31, 2017	February 14, 2018	21,346	0.3675
September 30, 2017	November 14, 2017	20,617	0.3550
June 30, 2017	August 14, 2017	19,891	0.3425
March 31, 2017	May 15, 2017	16,697	0.2875
December 31, 2016	February 14, 2017	16,116	0.2775
September 30, 2016	November 14, 2016	12,528	0.2625
June 30, 2016	August 12, 2016	11,693	0.2450
March 31, 2016	May 13, 2016	10,022	0.2100

(1) The dividend announced on January 15, 2019 for the fourth quarter of 2018 will be paid on February 14, 2019 to Class A shareholders of record at the close of business on January 31, 2019.

Subsidiary Distributions

TEP Distributions. The following table shows the distributions for the periods indicated:

		Distributions				
			General Partner			
Three Months Ended	Date Paid	Limited Partner Common Units	Incentive Distribution Rights	General Partner Units	Total	Distribution per Limited Partner Common Unit
		(in thousands, except per unit amounts)				
March 31, 2018	May 15, 2018	$ 71,370	$ 39,816	$ 1,267	$112,453	$ 0.9750
December 31, 2017	February 14, 2018	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

As a result of the TEP Merger, Tallgrass Equity and its wholly-owned subsidiary, Tallgrass Equity Investments, LLC, will receive all distributions paid by TEP for the second quarter of 2018 and subsequent periods.

Exchange Rights

Our current Class B shareholders (collectively, the "Exchange Right Holders") own an equal number of Tallgrass Equity units. The Exchange Right Holders, and any permitted transferees of their Tallgrass Equity units, each have the right to exchange all or a portion of their Tallgrass Equity units for Class A shares at an exchange ratio of one Class A share for each Tallgrass Equity unit exchanged, which we refer to as the Exchange Right. The Exchange Right may be exercised only if, simultaneously therewith, an equal number of our Class B shares are transferred by the exercising party to us. Upon such exchange, we will cancel the Class B shares received from the exercising party. During the year ended December 31, 2018, 2,821,332 Class A shares were issued and an equal number of Class B shares were cancelled as a result of the exercise of the Exchange Right. As of February 8, 2019, the Exchange Right Holders primarily consist of Kelso & Company and its affiliated investment funds ("Kelso"), The Energy & Minerals Group and its affiliated investment funds ("EMG"), and Tallgrass KC, LLC ("Tallgrass KC"), which is an entity owned primarily by certain members of TGE's management.

As discussed in Note 22 – *Subsequent Events*, on January 31, 2018, we announced that affiliates of Blackstone Infrastructure Partners (collectively, "BIP") had entered into a definitive purchase agreement with Kelso, EMG, and Tallgrass KC (collectively, the "Sellers"), pursuant to which BIP will acquire from the Sellers 100% of the membership interests in our general partner and an approximately 44% economic interest in us (the "Blackstone Acquisition"). One or more affiliates of GIC Special Investment Pte. Ltd., the infrastructure and private equity arm of GIC Pte. Ltd., Singapore's sovereign wealth fund, will be a minority investor in the Blackstone Acquisition. Following consummation of the Blackstone Acquisition, the Exchange Rights Holders are expected to consist of BIP and certain members of TGE's management.

Equity Distribution Agreements

Neither TGE or TEP currently have equity distribution agreements in place. TEP was previously a party to equity distribution agreements pursuant to which it sold from time to time through a group of managers, as its sales agents, TEP common units representing limited partner interests. Following the TEP Merger, these agreements were terminated effective July 2, 2018. During the year ended December 31, 2018, TEP did not issue any common units under its equity distribution agreements.

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

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

Repurchase of TEP Common Units Owned by TD

Following an offer received from TD with respect to TEP common units owned by TD not subject to the call option, TEP repurchased 736,262 TEP 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 TEP's general partner. These common units were deemed canceled upon TEP's purchase and as of such transaction date were no longer issued and outstanding.

Secondary Offering

On November 17, 2016, TGE entered into an Underwriting Agreement (the "Underwriting Agreement"), by and among TGE and certain selling shareholders named in the Underwriting Agreement (the "Selling Shareholders"), on one hand, and Goldman, Sachs & Co., as the sole underwriter (the "Underwriter"), on the other hand, providing for the offer and sale by the Selling Shareholders (the "Secondary Offering"), and purchase by the Underwriter, of 9,000,000 Class A shares at a price to the public of $22.00 per share. Pursuant to the Underwriting Agreement, the Selling Shareholders also granted the Underwriter an option for a period of 30 days to purchase up to an additional 1,350,000 Class A shares, on the same terms, which the Underwriter exercised in full.

In connection with the Secondary Offering, Class A shares were issued to the Selling Shareholders upon the exercise by each Selling Shareholder of its right to exchange all or a portion of its Tallgrass Equity units into Class A shares at an exchange ratio of one Class A share for each Tallgrass Equity unit exchanged (the "Exchange Right"). Pursuant to the terms of the Exchange Right, simultaneously therewith, the exercising Selling Shareholder transferred to TGE Class B shares in an amount equal to the number of Tallgrass Equity units exchanged by such exercising Selling Shareholder. Upon each such exchange, TGE cancelled the Class B shares received from the exercising Selling Shareholder. Immediately prior to the Secondary Offering, we and the Exchange Right Holders owned approximately 30.35% and 69.65% of the Tallgrass Equity units, respectively. At the completion of the Secondary Offering, we and the Exchange Right Holders owned 36.94% and 63.06% of the Tallgrass Equity units, respectively.

Private Placement

On April 28, 2016, TEP 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.

Noncontrolling Interests

As of December 31, 2018, noncontrolling interests in our subsidiaries consisted of a 44.21% interest in Tallgrass Equity held by the Exchange Right Holders, an approximate 40% membership interest in Deeprock Development, and a 37% membership interest in BNN Colorado. During the year ended December 31, 2018, we recognized contributions from and distributions to noncontrolling interests of $1.8 million and $327.6 million, respectively. Contributions from noncontrolling interests consisted primarily of contributions from DER to Deeprock Development. Distributions to noncontrolling interests consisted of Tallgrass Equity distributions to the Exchange Right Holders of $223.7 million, distributions to TEP unitholders of $97.7 million, and distributions to Deeprock Development and Pony Express noncontrolling interests of $6.2 million.

During the year ended December 31, 2017, we recognized contributions from and made distributions to noncontrolling interests of $1.6 million and $317.1 million, respectively. Contributions from noncontrolling interests consisted primarily of contributions from TD to Pony Express. Distributions to noncontrolling interests consisted of distributions to TEP unitholders of $185.7 million, Tallgrass Equity distributions to the Exchange Right Holders of $125.2 million, and distributions to Pony Express and Deeprock Development noncontrolling interests of $6.2 million.

During the year ended December 31, 2016, we recognized contributions from and made distributions to noncontrolling interests of $9.3 million and $249.1 million, respectively. Contributions from noncontrolling interests consisted primarily of contributions from TD to Pony Express. Distributions to noncontrolling interests consisted of distributions to TEP unitholders of $145.1 million, Tallgrass Equity distributions to the Exchange Right Holders of $97.5 million, and distributions to Pony Express and Water Solutions noncontrolling interests of $6.5 million.

Other Contributions and Distributions

During the year ended December 31, 2018, TGE recognized the following other contributions and distributions:

- TGE was deemed to have made a noncash capital distribution of $198.0 million, which represents the excess purchase price over the $53.8 million carrying value of the 5,619,218 TEP common units acquired as of February 7, 2018;
- TGE was deemed to have received a noncash capital contribution of $108.5 million, which represents the excess carrying value of the 25.01% membership interest in Rockies Express acquired as of February 7, 2018 over the fair value of the consideration paid; and
- TEP was deemed to have made a noncash capital distribution of $16.2 million, which represents the excess purchase price over the $33.8 million carrying value of the additional 2% membership interest in Pony Express acquired as of February 1, 2018.

During the year ended December 31, 2017, TGE recognized the following other contributions and distributions:

- TEP was deemed to have made a noncash capital distribution of $57.7 million, which represents the excess purchase price over the $82.3 million carrying value of the Terminals and NatGas net assets acquired January 1, 2017;
- TEP was deemed to have received a noncash capital contribution of $63.7 million, 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; and
- 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 19 – *Legal and Environmental Matters*.

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

- TEP was deemed to have made noncash capital distributions of $280.0 million, which represent the excess purchase price over the $417.7 million carrying value of the additional 31.3% membership interest in Pony Express acquired effective January 1, 2016, partially offset by the 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;
- TEP received contributions from TD of $17.9 million primarily to indemnify TEP for costs associated with Trailblazer's Pipeline Integrity Management Program, as discussed above.
- TGE distributed the remaining $1.6 million in remaining proceeds from the TGE IPO to the Exchange Right Holders that had been retained for short-term working capital needs.

12. Revenue from Contracts with Customers

As discussed in Note 2 – *Summary of Significant Accounting Policies*, we adopted the guidance in ASC Topic 606 effective January 1, 2018 using the modified retrospective method of adoption. As a result, revenue reported for the years ended December 31, 2017 and 2016 have not been revised. The following tables provide the impact of ASC Topic 606 on our consolidated balance sheet as of December 31, 2018 and the consolidated statements of income for the year ended December 31, 2018:

	December 31, 2018			
	As currently reported	Under previous guidance	Impact of ASC Topic 606	
	(in thousands)			
Unconsolidated investments	$ 1,861,686	$ 1,773,849	$ 87,837	(1)

	Year Ended December 31, 2018			
	As currently reported	Under previous guidance	Impact of ASC Topic 606	
	(in thousands)			
Crude oil transportation services	$ 398,334	$ 398,329	$ 5	(2)
Sales of natural gas, NGLs, and crude oil	$ 168,586	$ 173,055	$ (4,469)	(3)
Processing and other revenues	$ 99,445	$ 104,117	$ (4,672)	(1)(3)
Cost of sales	$ 114,815	$ 123,458	$ (8,643)	(2)(3)
Equity in earnings of unconsolidated investments	$ 306,819	$ 261,848	$ 44,971	(1)
Net income attributable to TGE	$ 137,127	$ 121,402	$ 15,725	
Basic net income per Class A share	$ 1.27	$ 1.13	$ 0.14	
Diluted net income per Class A share	$ 1.27	$ 1.13	$ 0.14	

(1) Reflects the impact on our investment in Rockies Express and the management fee collected by NatGas of the cumulative effect adjustment at Rockies Express, which 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 rates that vary throughout the term of the contract. 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.

(2) Reflects the impact to revenue and cost of sales to value PLA barrels collected under certain crude oil transportation arrangements at their contract inception fair value in revenue and record an associated lower of cost or net realizable value adjustment in cost of sales.

(3) Reflects the reclassification of certain gathering and processing fees collected under arrangements determined to be supply arrangements, rather than customer arrangements under ASC 606, to cost of sales and the reclassification of certain commodities retained as consideration for processing services to processing fee revenue.

Disaggregated Revenue

A summary of our revenue by line of business is as follows:

	Year Ended December 31, 2018				
	Natural Gas Transportation segment	Crude Oil Transportation segment	Gathering, Processing, & Terminalling segment	Corporate and Other	Total Revenue
			(in thousands)		
Crude oil transportation - committed shipper revenue	$ —	$ 392,276	$ —	$ —	$ 392,276
Natural gas transportation - firm service	128,041	—	—	(4,585)	123,456
Water business services	—	—	52,333	—	52,333
Natural gas gathering & processing fees	—	—	24,109	—	24,109
All other [(1)]	11,223	45,888	18,444	(53,950)	21,605
Total service revenue	139,264	438,164	94,886	(58,535)	613,779
Natural gas liquids sales	—	—	101,382	—	101,382
Natural gas sales	1,195	—	29,558	—	30,753
Crude oil sales	—	6,290	652	—	6,942
Total commodity sales revenue	1,195	6,290	131,592	—	139,077
Total revenue from contracts with customers	140,459	444,454	226,478	(58,535)	752,856
Other revenue [(2)]	—	—	53,187	(12,784)	40,403
Total revenue [(3)]	$ 140,459	$ 444,454	$ 279,665	$ (71,319)	$ 793,259

(1) Includes revenue from crude oil transportation walk up shippers, crude oil terminal services, interruptible natural gas transportation and storage, and natural gas park and loan service.

(2) Includes lease and derivative revenue not subject to ASC 606.

(3) Excludes $930.8 million of revenue recognized at Rockies Express, BNN Colorado, and Pawnee Terminal for the year ended December 31, 2018. See Note 7 – *Investments in Unconsolidated Affiliates* for additional information.

Performance Obligations

A performance obligation is a promise in a contract to transfer a distinct good or service to the customer, and is the unit of account in ASC Topic 606. A contract's transaction price is allocated to each distinct performance obligation and recognized as revenue when, or as, the performance obligation is satisfied. The majority of our contracts have a single performance obligation and are billed and collected monthly.

All of our segments engage in commodity sales, in which our performance obligations include an obligation to deliver the specified volume of a commodity to the designated receipt point. Revenue from commodity sales is recognized at a point in time when the customer obtains control of the commodity, typically upon delivery to the designated delivery point when the customer accepts and takes possession of the commodity.

In the Natural Gas Transportation segment, our performance obligations typically include an obligation to stand ready to provide natural gas transportation, storage, or an integrated transportation and storage service over the life of the contract, which is a series. These performance obligations are satisfied over time using each day of service to measure progress toward satisfaction of the performance obligation.

In the Crude Oil Transportation segment, our performance obligations typically include an obligation to provide crude oil transportation services over the life of the contract, which is a series. These performance obligations are satisfied over time using barrels delivered to measure progress toward satisfaction of the performance obligation.

In the Gathering, Processing & Terminalling segment, the performance obligations vary based on the operating asset and type of contract. In our natural gas gathering and processing arrangements, performance obligations typically include an obligation to provide an integrated processing service over the life of the contract, which is a series. These performance obligations are satisfied over time using each unit of gas processed to measure progress toward satisfaction of the performance obligation. In our freshwater supply arrangements, performance obligations typically include an obligation to deliver a specified volume of water to the designated receipt point. These performance obligations are satisfied at a point in time when the customer obtains control of the water. In our produced water gathering and disposal arrangements, performance obligations typically include an obligation to provide an integrated produced water gathering and disposal service over the life of the contract, which is a series. These performance obligations are satisfied over time using barrels disposed to measure progress toward satisfaction of the performance obligation.

On December 31, 2018, we had $1.6 billion of remaining performance obligations at our consolidated subsidiaries, which we refer to as total backlog. Total backlog includes performance obligations under long-term crude oil transportation contracts with committed shippers, natural gas firm transportation and firm storage contracts, and certain water business service contracts with minimum volume commitments, and excludes variable consideration that is not estimated at contract inception, as discussed further below. We expect to recognize the total backlog during future periods as follows (in thousands):

Year	Estimated Revenue
2019	$ 532,549
2020	357,226
2021	170,713
2022	163,852
2023	140,101
Thereafter	210,625
Total	$ 1,575,066

Contract Estimates

Accounting for long-term contracts involves the use of various techniques to estimate total contract revenue. Contract estimates are based on various assumptions to project the outcome of future events that often span several years. These assumptions include the anticipated volumes of crude oil expected to be delivered by our customers for transport in future periods.

The nature of our contracts gives rise to several types of variable consideration, including PLA, volumetric charges for actual volumes delivered, overrun charges, and other fees that are contingent on the actual volumes delivered by our customers. As the amount of variable consideration is allocable to each distinct performance obligation within the series of performance obligations that comprise the single performance obligation and the uncertainty related to the consideration is resolved each month as the distinct service is provided, we do not estimate the total variable consideration for the single overall performance obligation. Consequently, we are able to include in the transaction price each month the actual amount of variable consideration because no uncertainty exists surrounding the services provided that month.

Certain of our contracts include provisions in which a portion of the consideration is noncash. In our Crude Oil Transportation segment, we collect PLA from our customers. As crude oil is transported, we earn, and take title to, a portion of the oil transported for our services. Any PLA that remains after replacing losses in transit can be sold. Where PLA is determined to be a component of compensation for the transportation services provided, crude oil retained is recognized in revenue at its contract inception fair value. In our Gathering, Processing & Terminalling segment, we retain commodity products as consideration under certain of our gathering and processing arrangements. Processing fee revenue is recorded when the performance obligation is completed based on the value of the product received at the time services are performed. At this time, the variability of the non-cash consideration related to both form (price) and other-than-form (volume and product mix), which are interrelated, is resolved.

As a significant change in one or more of these estimates could affect the amount and timing of revenue recognized under our customer contracts, we review and update our contract-related estimates regularly.

Contract Balances

The timing of revenue recognition, billings, and cash collections may result in billed accounts receivable, unbilled receivables (contract assets), and deferred revenue (contract liabilities) on our consolidated balance sheets. Revenue is generally billed and collected monthly based on services provided or commodity volumes sold. In our Crude Oil Transportation segment, we recognize shipper deficiencies, or deferred revenue, for 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. These shipper deficiencies are charged at the committed tariff rate per barrel and recorded as a contract liability until the barrels are physically transported and delivered, or when the likelihood that the customer will utilize the deficiency balance becomes remote. We also recognize contract liabilities, in the form of deferred revenue, under certain water business services contracts in the Gathering, Processing & Terminalling segment. Contract balances as of December 31, 2018 were as follows:

	December 31, 2018	January 1, 2018
	(in thousands)	
Accounts receivable from contracts with customers	$ 80,935	$ 61,888
Other accounts receivable	151,414	56,727
Receivable from related parties	3,748	1,340
Accounts receivable, net	$ 236,097	$ 119,955
Deferred revenue from contracts with customers [1]	$ 111,095	$ 88,471

[1] Revenue recognized during the year ended December 31, 2018 that was included in the deferred revenue balance at the beginning of the period was $12.0 million. This revenue primarily represented the utilization of shipper deficiencies at Pony Express.

13. Commitments & Contingent Liabilities

Leases and Right of Way Agreements

Rent expense under operating leases and right of way agreements totaled approximately $1.4 million, $9.5 million, and $16.5 million for the years ended December 31, 2018, 2017, and 2016, respectively.

At December 31, 2018, future minimum rental commitments under major, non-cancelable leases and right of way ("ROW") agreements were as follows (in thousands):

Year	Operating Lease and ROW Obligations	Capital Lease Obligations
2019	$ 1,818	$ 449
2020	1,757	449
2021	1,056	449
2022	796	449
2023	679	449
Thereafter	3,153	17,770
Total	$ 9,259	$ 20,015

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 Note 3 - *Acquisitions and Dispositions*, 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 lease obligations consist of the PLT land site lease, as discussed in Note 3 - *Acquisitions and Dispositions*. The PLT land site lease includes a bargain purchase option exercisable after the initial lease term. PLT satisfied the capital lease obligation of $30.7 million at lease inception, and as a result has no imputed interest on the future minimum rental commitments in the table above. These future commitments represent certain administrative fees and estimated payments to the Plaquemines Port & Harbor Terminal District which approximate the ad valorem taxes that would be assessed if PLT acquired the land directly.

Capital Expenditures

We had committed approximately $39.6 million for the future purchase of property, plant and equipment at December 31, 2018.

Other Purchase Obligations

At December 31, 2018, future minimum commitments under long-term, non-cancelable contracts for other purchase obligations were as follows (in thousands):

Year	Total
2019	$ 13,467
2020	11,198
2021	6,677
2022	5,604
2023	5,614
Thereafter	13,231
Total	$ 55,791

14. Net Income per Class A Share

Basic net income per Class A share is determined by dividing net income attributable to TGE by the weighted average number of outstanding Class A shares during the period. Class B shares do not share in the earnings of TGE. Accordingly, basic and diluted net income per Class B share has not been presented.

Diluted net income per Class A share is determined by dividing net income attributable to TGE by the weighted average number of outstanding diluted Class A shares during the period. For purposes of calculating diluted net income per Class A share, we considered the impact of possible future exercises of the Exchange Right by the Exchange Right Holders on both net income attributable to TGE and the diluted weighted average number of Class A shares outstanding. The Exchange Right Holders refers to the group of persons who collectively own all TGE's outstanding Class B shares and an equivalent number of Tallgrass Equity units. The Exchange Right Holders are entitled to exercise the right to exchange their Tallgrass Equity units (together with an equivalent number of TGE Class B shares) for TGE Class A shares at an exchange ratio of one TGE Class A share for each Tallgrass Equity unit exchanged, which we refer to as the Exchange Right. As of February 8, 2019, the Exchange Right Holders primarily consist of Kelso, EMG and Tallgrass KC. Following consummation of the Blackstone Acquisition, the Exchange Right Holders will primarily consist of BIP and certain members of TGE's management.

Pursuant to the TGE partnership agreement and the Tallgrass Equity limited liability company agreement, our capital structure and the capital structure of Tallgrass Equity will generally replicate one another in order to maintain the one-for-one exchange ratio between the Tallgrass Equity units and Class B shares, on the one hand, and our Class A shares, on the other hand. As a result, the exchange of any Class B shares for Class A shares does not have a dilutive effect on basic net income per Class A share. However, for the years ended December 31, 2018 and 2016, the potential issuance of TGE Equity Participation Shares would have had a dilutive effect on basic net income per Class A share. The potential issuance of TGE Equity Participation Shares would not have had a dilutive effect on the basic net loss per Class A share for the year ended December 31, 2017.

All net income or loss from Terminals and NatGas prior to TEP's acquisition on January 1, 2017 is allocated to predecessor operations in the consolidated statements of income. Accordingly, no net income or loss from Terminals and NatGas is allocated to our Class A shareholders. 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.

The following table illustrates the calculation of net income per Class A share for the years ended December 31, 2018, 2017, and 2016:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands, except per unit amounts)		
Basic Net Income per Class A Share:			
Net income (loss) attributable to TGE, excluding predecessor operations interest	$ 137,127	$ (128,729)	$ 26,794
Basic weighted average Class A Shares outstanding	107,586	58,076	48,856
Basic net income (loss) per Class A share	$ 1.27	$ (2.22)	$ 0.55
Diluted Net Income per Class A Share:			
Net income (loss) attributable to TGE, excluding predecessor operations interest	$ 137,127	$ (128,729)	$ 26,794
Incremental net income attributable to TGE including the effect of the assumed issuance of Equity Participation Shares	2,108	—	9
Net income (loss) attributable to TGE including incremental net income from assumed issuance of Equity Participation Shares	$ 139,235	$ (128,729)	$ 26,803
Basic weighted average Class A Shares outstanding	107,586	58,076	48,856
Equity Participation Shares equivalent shares	2,231	—	33
Diluted weighted average Class A Shares outstanding	109,817	58,076	48,889
Diluted net income (loss) per Class A Share	$ 1.27	$ (2.22)	$ 0.55

15. Major Customers and Concentration of Credit Risk

During the years ended December 31, 2018 and 2017, one non-affiliated customer, Continental Resources, Inc. ("Continental Resources"), accounted for $81.9 million (10%) and $100.2 million (15%), of our total operating revenues, respectively. 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. Revenues from Continental Resources for the year ended December 31, 2018 were earned in our Crude Oil Transportation and Gathering, Processing & Terminalling segments. Revenues from Continental Resources for the years ended December 31, 2017 and 2016 were earned in our Crude Oil Transportation segment. Revenues from Shell for the year ended December 31, 2016 were earned in our Natural Gas Transportation, Crude Oil Transportation, and Gathering, Processing & Terminalling segments.

For the year ended December 31, 2018, 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	58%
Crude Oil Transportation	84%
Gathering, Processing & Terminalling	60%

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.

16. Equity-Based Compensation

Long-term Incentive Plan

We have two long-term incentive plans. The Tallgrass Energy GP, LLC Long-Term Incentive Plan (f/k/a the TEGP Management, LLC Long-Term Incentive Plan), was originally adopted by our general partner effective as of May 1, 2015, and was amended and restated effective August 2, 2018 (as amended, the "TGE LTIP"). In addition, the Tallgrass MLP GP, LLC Long-Term Incentive Plan was originally adopted by TEP GP effective as of May 13, 2013, and was amended and restated effective August 2, 2018 (as amended, the "Legacy LTIP" and together with the TGE LTIP, the "Plans"). In connection with the completion of the TEP Merger effective June 30, 2018, the Legacy LTIP was assumed by our general partner.

Awards under the Plans may consist of, among others, unrestricted shares, restricted shares, equity participation shares, options and share appreciation rights which may be granted to (i) the employees of our general partner and its affiliates who perform services for us, (ii) the non-employee directors of our general partner and (iii) the consultants who perform services for us. The TGE LTIP limits the number of shares that may be delivered pursuant to awards to 3,144,589 Class A shares, and the Legacy LTIP limits the number of shares that may be delivered pursuant to awards under such plan to 20,000,000 Class A shares, subject in each case to any adjustment due to recapitalization, reorganization or a similar event permitted under the applicable Plan. Shares that are forfeited or withheld to satisfy exercise price or tax withholding obligations are available for delivery pursuant to other awards under the applicable Plan. The Plans are administered by the board of directors of our general partner or a committee thereof, which is referred to as the plan administrator.

Equity Participation Shares

Vesting of the Equity Participation Shares granted to date is contingent on certain service and performance conditions. The Equity Participation Shares are non-participating; as such participants are not entitled to receive any dividends with respect to the Equity Participation Shares unless the participant receives a separate grant of Distribution Equivalent Rights. At this time, no grants of Distribution Equivalent Rights have been made.

The Equity Participation Share grants under the Plans are measured at their grant date fair value. The Equity Participation Shares are non-participating; therefore, the grant date fair value is discounted from the grant date fair value of TGE's Class A shares for the present value of the expected future dividends during the vesting period. Effective June 30, 2018 with the completion of the TEP Merger, as discussed in Note 1 – *Description of Business*, TEP's outstanding Equity Participation Units were converted to Equity Participation Shares at a ratio of 2.0 Equity Participation Shares for each outstanding TEP Equity Participation Unit. Total equity-based compensation cost related to the Equity Participation Share grants was approximately $7.6 million, $1.6 million, and $1.4 million for the years ended December 31, 2018, 2017, and 2016 respectively, excluding costs associated with TEP's Equity Participation Units prior to the TEP Merger. Of the total compensation cost, $7.6 million, $0.2 million, and $0.2 million for the years ended December 31, 2018, 2017, and 2016 respectively, were recognized as compensation expense at TGE and the remainder was allocated to TEP and TD. As of December 31, 2018, $34.3 million of total compensation cost related to non-vested Equity Participation Shares is expected to be recognized over a weighted-average period of 3.2 years.

The following table summarizes the changes in the Equity Participation Shares outstanding for the years ended December 31, 2018, 2017 and 2016:

	Equity Participation Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2016	160,000	$ 27.97
Granted	45,000	18.22
Outstanding at December 31, 2016	205,000	25.83
Granted	30,000	23.66
Vested	(10,002)	(14.26)
Outstanding at December 31, 2017	224,998	25.91
Granted	1,138,200	17.01
Converted [1]	1,786,310	18.20
Vested	(20,664)	(19.19)
Forfeited	(79,200)	(20.62)
Outstanding at December 31, 2018	3,049,644	$ 18.25

(1) Reflects TEP's outstanding Equity Participation Units that were converted to Equity Participation Shares at a ratio of 2.0 Equity Participation Shares for each outstanding TEP Equity Participation Unit upon completion of the TEP Merger as discussed above.

17. Income Taxes

Income tax expense is estimated using the tax rate in effect or to be in effect during the relevant periods in the jurisdictions in which we operate. Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes and are stated at enacted tax rates expected to be in effect when taxes are actually paid or recovered. To the extent we do not consider it more likely than not that a deferred tax asset will be recovered, a valuation allowance is established. We record a valuation allowance to reduce our deferred tax assets to the amount we believe is more likely than not to be realized. In making these determinations we consider historical and projected taxable income, and ongoing prudent and feasible tax planning strategies, in assessing the appropriateness of a valuation allowance. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective.

U.S. Federal and State Taxes

Although we are organized as a limited partnership, we have elected to be treated as a corporation for U.S. federal income tax purposes and are therefore subject to both U.S. federal and state income taxes. We are projecting a loss for both U.S. federal and state income taxes for the tax year ended December 31, 2018. As a result, there is no current provision for income taxes for the year ended December 31, 2018.

Tax Components

Components of the deferred income tax expense are as follows:

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Deferred income tax expense:			
Federal income tax	$ 41,585	$ 200,787	$ 15,587
State income tax	14,124	7,671	2,154
Total deferred income tax expense	$ 55,709	$ 208,458	$ 17,741

The difference between tax expense based on the statuary federal income tax rate and our effective tax expense is summarized as follows:

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Net income before tax	$ 523,380	$ 432,443	$ 267,780
Less: Predecessor operations interest in net income	—	—	(6,995)
Net income before tax, excluding predecessor operations interest	523,380	432,443	260,785
Less: Net income attributable to noncontrolling interests	(330,544)	(352,714)	(216,250)
Net income subject to tax	$ 192,836	$ 79,729	$ 44,535
Federal statutory income tax rate	21%	35%	35%
Income tax at statutory rate	$ 40,496	$ 27,905	$ 15,587
State income taxes, net of federal benefit	5,419	2,392	1,592
Change in state tax rate	8,705	1,353	562
Other	1,089	—	—
Valuation allowance	—	3,926	—
Total income tax expense before change in tax legislation	$ 55,709	$ 35,576	$ 17,741
Impact of federal tax legislation on deferred tax asset	—	172,037	—
Impact of federal tax legislation on valuation allowance	—	845	—
Total income tax expense	$ 55,709	$ 208,458	$ 17,741
Effective tax rate	10.6%	48.2%	6.8%

Deferred tax assets result from the following:

	December 31, 2018	December 31, 2017
	(in thousands)	
Deferred tax assets:		
Investment in partnerships	$ 198,290	$ 269,136
Net operating losses	80,012	48,632
Deferred tax assets before valuation allowance	$ 278,302	$ 317,768
Valuation allowance	(4,771)	(4,771)
Total deferred tax assets	$ 273,531	$ 312,997
Deferred tax liability:		
Equity earnings adjustment pursuant to ASC 606	$ 817	$ —

On May 12, 2015, as a result of the transfer of the ownership interest in Tallgrass Equity as part of the Reorganization Transactions in connection with the TGE IPO, we recognized a deferred tax asset of $445.2 million. In November 2016, we completed the Secondary Offering as discussed in Note 11 – *Partnership Equity*. In connection with the resulting transfer of Tallgrass Equity Units, we recognized an additional deferred tax asset of $86.8 million. During 2018, a portion of the Exchange Right Holders exercised their Exchange Right as discussed in Note 11 – *Partnership Equity.* In connection with the resulting transfer of Tallgrass Equity Units, we recognized an additional deferred tax asset of $15.4 million. These transfers of ownership were accounted for at the historical carrying basis for GAAP accounting purposes, but recorded at the value of the consideration paid for U.S. federal income tax purposes. The tax rates that apply when the deferred tax balances ultimately reverse are inherent in the realization of the deferred tax balances. State tax rates can change from year to year based upon changes in both state apportionment percentages and state tax laws.

As of December 31, 2018, we had a federal net operating loss carry forward of $328.2 million and various state net operating loss carry forwards. The determination of the state net operating loss carry forwards is dependent upon apportionment percentages and state laws that can change from year to year and impact the amount of such carry forwards. If not utilized, the federal net operating loss carry forward will expire between 2035 and 2037 and the state operating loss carry forwards will expire between 2025 and 2037. We believe that it is more likely than not that the benefit from certain state operating loss carryforwards will not be realized. In recognition of this risk, we have provided a valuation allowance on the deferred tax assets relating to these carryforwards.

On December 22, 2017, legislation referred to as the "Tax Cuts and Jobs Act" ("TCJA") was signed into law. Substantially all provisions of the TCJA are effective for taxable years beginning after December 31, 2017. The TCJA includes amendments to the Internal Revenue Code of 1986 that significantly change the taxation of individuals and business entities. Pursuant to ASC Topic 740, Income Taxes (ASC 740), we recognized the tax effect of the TCJA changes during the year ended December 31, 2017, the period in which the law was enacted. ASC 740 requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. Accordingly, we remeasured our deferred tax asset based on the new tax rates, resulting in an increase to our tax provision of $172.9 million for the year ended December 31, 2017.

The 2015 through 2018 tax years are open to examination for federal and state tax.

18. Regulatory Matters

There are no regulatory proceedings challenging the rates of Pony Express, Rockies Express, or TIGT. On June 29, 2018, Trailblazer Pipeline Company LLC ("Trailblazer") filed a general rate case with the FERC pursuant to Section 4 of the Natural Gas Act ("NGA"), as further described below. We have also made certain regulatory filings with the FERC, including the following:

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.

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. RP16-702-000 and RP17-240-000

On March 1, 2016, Rockies Express made its annual fuel tracker filing with a proposed effective date of April 1, 2016 in Docket No. RP16-702-000. 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. RP17-240-000. The FERC issued an order accepting the filing on December 29, 2016.

Electric Power Charge Clarification - FERC Docket No. RP17-285-000

On December 21, 2016, in Docket No. RP17-285-000, 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. RP17-401-000 and RP17-1064-000

On February 13, 2017, in Docket No. RP17-401-000, 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. RP17-1064-000 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. RP18-228-000

On December 1, 2017, in Docket No. RP18-228-000, 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. On April 4, 2018, the FERC issued a letter order accepting Rockies Express' proposal, subject to certain modifications. Rockies Express submitted a compliance filing reflecting the approved tariff provisions and requested modifications on April 10, 2018. No comments on the compliance filing were submitted by the comment deadline of April 16, 2018. On April 18, 2018, the FERC issued an order accepting Rockies Express' compliance filing effective April 19, 2018.

2018 Annual FERC Fuel Tracking Filing - FERC Docket No. RP18-453-000

On February 20, 2018, in Docket No. RP18-453-000, Rockies Express made its annual fuel and power cost tracker filing with a proposed effective date of April 1, 2018. The FERC issued an order accepting the filing on March 19, 2018.

Cheyenne Hub Enhancement Project - FERC Docket No. CP18-103-000

On March 2, 2018, Rockies Express submitted an application pursuant to section 7(c) of the NGA for a certificate of public convenience and necessity authorizing the construction and operation of certain booster compressor units and ancillary facilities located at the Cheyenne Hub in Weld County, Colorado that will enable Rockies Express to provide a new hub service allowing for firm receipts and deliveries between Rockies Express and certain other interconnected pipelines at the Cheyenne Hub. Rockies Express filed this certificate application in conjunction with a concurrently filed certificate application by Cheyenne Connector, LLC ("Cheyenne Connector") for the Cheyenne Connector Pipeline Project further described below. The comment period for the Cheyenne Hub Enhancement Project closed on April 9, 2018. To date, various comments have been filed by market participants and others regarding the proposed project. Rockies Express has also responded to data requests from the FERC's relevant program offices. On October 11, 2018, the FERC issued a Notice of Schedule of Environmental Review setting December 18, 2018 as the date of issuance of the Environmental Assessment and March 18, 2019 as the deadline for decisions by other federal agencies on requests for authorizations for the proposed project. On December 18, 2018, the FERC issued the Environmental Assessment.

Rockies Express Form No. 501-G Filing - FERC Docket No. RP19-412-000

On December 6, 2018, Rockies Express submitted its one-time informational filing in compliance with Order No. 849, which required interstate natural gas pipelines to make a one-time informational filing on the rate effect of the changes in tax laws and policy following the Tax Cuts and Jobs Act and the FERC's changes to its Income Tax Policy Statement following the decision of the U.S. Court of Appeals for the D.C. Circuit in United Airlines, Inc. v. FERC in 2016. The filing remains pending before the FERC.

Cheyenne Connector

Cheyenne Connector Pipeline Project - FERC Docket No. CP18-102-000

On March 2, 2018, Cheyenne Connector, an indirect subsidiary of TGE, submitted an application pursuant to section 7(c) of the NGA for a certificate of public convenience and necessity to construct and operate a 70-mile, 36-inch pipeline to transport natural gas from multiple gas processing plants in Weld County, Colorado to Rockies Express' Cheyenne Hub. The comment period for the Cheyenne Connector Pipeline Project closed on April 9, 2018. To date, various comments have been filed by market participants and others regarding the proposed project. Cheyenne Connector has also responded to data requests from the FERC's relevant program offices. On October 11, 2018, the FERC issued a Notice of Schedule of Environmental Review setting December 18, 2018 as the date of issuance of the Environmental Assessment and March 18, 2019 as the deadline for decisions by other federal agencies on requests for authorizations for the proposed project. On December 18, 2018, the FERC issued the Environmental Assessment.

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 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.

2018 Annual Fuel Tracker Filing - FERC Docket No. RP18-533-000

On March 1, 2018, in Docket No. RP18-533-000, TIGT made its annual fuel tracker filing with a proposed effective date of April 1, 2018. The FERC accepted the filing on March 22, 2018.

TIGT Form No. 501-G Filing - FERC Docket No. RP19-423-000

On December 6, 2018, TIGT submitted its one-time informational filing in compliance with Order No. 849, which required interstate natural gas pipelines to make a one-time informational filing on the rate effect of the changes in tax laws and policy following the Tax Cuts and Jobs Act and the FERC's changes to its Income Tax Policy Statement following the decision of the U.S. Court of Appeals for the D.C. Circuit in United Airlines, Inc. v. FERC in 2016. On December 18, 2018, one protest and one set of comments were filed by intervenors in the docket. The filing remains pending before the FERC.

Trailblazer

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.

2018 Annual Fuel Tracker Filing - FERC Docket No. RP18-580-000

On March 22, 2018, in Docket No. RP18-580-000, Trailblazer made its annual fuel tracker filing with a proposed effective date of May 1, 2018. The FERC accepted the filing on April 20, 2018.

General Rate Case Filing - FERC Docket No. RP18-922-000, et seq.

On June 29, 2018, Trailblazer filed a general rate case with the FERC, which satisfies the requirement set forth in the settlement resolving Trailblazer's previous general rate case that Trailblazer file a new general rate case with rates to be effective no later than January 1, 2019. The June 29, 2018 filing reflects an overall increase to Trailblazer's cost of service. In the filing, Trailblazer is proposing to maintain its existing bifurcated firm transportation service rate design as well as its current tracking methodologies for the treatment of Fuel and Lost and Unaccounted For ("FL&U") gas and electric power costs. The proposed rates include an increase in rates on Trailblazer's Existing System Firm Transportation Service. The overall rate increase would be partially offset by a proposed decrease in rates for Expansion System Firm Transportation Service and interruptible services. Trailblazer is also proposing to include a cost recovery mechanism in its tariff to recover future eligible costs related to system safety, integrity, reliability, environmental and cybersecurity issues. Under the NGA and the FERC's regulations, Trailblazer's shippers and other interested parties, including the FERC's Trial Staff, have the right to challenge any aspect of Trailblazer's rate case filing. On July 11, 2018, four protests were filed that challenge various aspects of Trailblazer's rate case filing. FERC action remains pending.

On July 31, 2018, the FERC issued an Order accepting and suspending the rate case filing, and establishing hearing and settlement procedures. In the Order, the FERC approved the as-filed rate decreases for Expansion System Firm Transportation Service, as well as Trailblazer's interruptible services, effective August 1, 2018. The Commission also established a paper hearing to examine the extent to which Trailblazer is entitled to an income tax allowance. All remaining issues, including the proposed rate increases to Existing System Firm Transportation Service have been set for hearing and are accepted effective January 1, 2019, subject to refund. On August 30, 2018, Trailblazer and certain of Trailblazer's shippers filed a request for rehearing of the July 31, 2018 Order, which remains pending before the FERC. Consistent with the July 31, 2018 Order, on August 30, 2018, certain of Trailblazer's shippers and other interested parties filed initial briefs regarding the Income Tax Allowance issue. Trailblazer filed its reply brief regarding the same on September 14, 2018. On November 1, 2018, Trailblazer filed a supplement to its reply brief addressing a recent FERC order regarding the appropriate methodology used to calculate return on equity and discussing the impact of such order on Trailblazer's proposed Income Tax Allowance. The briefs remain pending before the FERC. On August 28, 2018, the participants attended an initial settlement conference. On September 12, 2018, the Chief Administrative Law Judge issued an order continuing settlement judge procedures. On November 15, 2018, the participants attended a second settlement conference. On December 31, 2018, Trailblazer filed a motion with the FERC to move the suspended tariff records into effect as of January 1, 2019. In January 2019, the participants attended a third settlement conference. A fourth settlement conference is scheduled in late February 2019.

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, IS17-464-000, and IS17-465-000 to increase the contract and non-contract rates by an amount reflecting the 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, which became 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, which became effective on February 1, 2018.

On February 28, 2018, Pony Express filed with the FERC in Docket No. IS18-199-000 certain changes to its tariffs to reflect a new origin point in Platteville, Colorado, which became effective on April 1, 2018.

On March 1, 2018, Pony Express submitted proposed revisions to its Rules and Regulations Tariff in Docket No. IS18-204-000 to establish the right to accept "Specialty Batches" of oil that do not conform to the Quality Specifications reflected in the tariff, provided that the acceptance is operationally feasible. These tariff changes became effective on April 1, 2018.

On April 11, 2018, Pony Express filed with the FERC in Docket No. IS18–267–000 certain changes to its tariffs to reflect additional contract rates from a new origin point in Platteville, Colorado, which became effective May 1, 2018.

On May 2, 2018, Pony Express filed with the FERC in Docket No. IS18-297-000 certain changes to its rules and regulations applicable to new intermediate off-system storage points, which became effective May 15, 2018.

On May 31, 2018, Pony Express made tariff filings with the FERC in Docket No. IS18-570-000 to increase the contract and non-contract rates by an amount reflecting the FERC annual index adjustment of approximately 4.4% which became effective July 1, 2018.

On January 11, 2019, Pony Express filed with the FERC in Docket No. IS19-145-000 certain changes to its tariffs to incorporate the Sterling origin point in Logan County, Colorado in the published rate schedules, to establish a line fill return rate from the Natoma origin point, and to make minor clarifying edits.

Iron Horse

Petition for Declaratory Order - FERC Docket No. OR19-9-000

On November 9, 2018, Iron Horse filed a Petition for Declaratory Order with the FERC, requesting approval of Iron Horse's proposed rate structures, Committed Shipper rights, and prorationing provisions for shippers and various other aspects of the Transportation Service Agreement for service on the pipeline. The Petition is pending before the FERC.

19. 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 matters 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, 2018 and 2017.

Rockies Express

Ohio Public Utility Excise Tax

The Ohio Tax Commissioner has assessed Rockies Express a public utility excise tax on transactions concerning product that entered and exited Rockies Express within the state of Ohio. This tax applies to gross receipts from all business conducted within the state, but exempts all receipts derived wholly from interstate business. Rockies Express has disputed any obligation to pay Ohio's public utility excise tax, but has paid the taxes as assessed in order to preserve its right to appeal. The dispute is currently pending before the Ohio Supreme Court, with a final decision possible by the end of 2019. It is Rockies Express' position that the relevant statute exempts receipts derived wholly from interstate business from the public utility excise tax. The Ohio Supreme Court and the United States Supreme Court have both held that, once it enters an interstate pipeline, natural gas is moving in "interstate commerce" for the duration of its journey until it is delivered to a local distribution system. While it is difficult to accurately predict how the Ohio Supreme Court will decide the case, Rockies Express is optimistic about the ultimate outcome.

As of December 31, 2018, Rockies Express has paid public utility excise taxes to the state of Ohio totaling $7.1 million, accrued an additional $3.3 million for amounts expected to be assessed through the year ended December 31, 2018, and has recognized a $10.4 million deposit representing the anticipated refund of the public utility excise taxes paid.

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. We received our 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 currently 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 $7.4 million and $7.7 million at December 31, 2018 and 2017, respectively.

Rockies Express

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. The release required Rockies Express to shut off the flow through the segment until February 27, 2018, when temporary repairs were completed allowing the segment to be placed back into service. Total cost of remediation was approximately $6.1 million prior to any insurance recoveries. Permanent repairs were completed in September 2018. As of February 8, 2019, Rockies Express has recovered a significant majority of these costs from insurance.

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 continued performing remediation to increase and maximize its operating capacity over the long-term and spent approximately $21 million during 2018 for this pipe replacement and remediation work. As of October 2018, the pipeline was returned to its maximum allowable operating capacity. 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 TEP's 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 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, 2016, and 2017, Pony Express completed approximately $18 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. Remediation work was substantially complete as of March 31, 2018.

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.

20. Reportable Segments

Our operations are located in the United States. We are organized into three reportable segments: (1) Natural Gas Transportation, (2) Crude Oil Transportation, and (3) Gathering, Processing & Terminalling. 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 Senior Notes, public company costs, and equity-based compensation expense.

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 provide services to on-system customers (such as third-party LDCs), industrial users and other shippers. The Natural Gas Transportation segment includes our aggregate 75% membership interest in Rockies Express, inclusive of the additional 25.01% membership interest acquired effective February 7, 2018.

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.

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 sold in local wholesale markets or delivered into pipelines for transportation to additional end markets; our crude oil terminal services; water business services provided primarily to the oil and gas exploration and production industry; the transportation of NGLs; and Stanchion.

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. During the second quarter of 2018, upon completion of the TEP Merger, management updated TGE's internal reporting. Beginning in the second quarter of 2018, we consider Adjusted EBITDA, as described below, to be our primary segment performance measure.

We consider Adjusted EBITDA to be 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 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 and deficiency payments received from or utilized by our customers. Adjusted EBITDA is calculated and presented at the Tallgrass Equity level, before consideration of noncontrolling interest associated with the Exchange Right Holders, which we believe provides investors the most complete picture of our overall financial and operational results.

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

	Year Ended December 31,								
	2018			2017			2016		
Revenue:	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue
	(in thousands)								
Natural Gas Transportation..........	$140,459	$ (4,661)	$135,798	$141,021	$ (6,694)	$134,327	$135,097	$ (5,641)	$129,456
Crude Oil Transportation..........	444,454	(39,319)	405,135	364,574	(10,676)	353,898	380,503	(370)	380,133
Gathering, Processing & Terminalling	279,665	(27,339)	252,326	186,211	(18,538)	167,673	113,533	(11,460)	102,073
Total revenue	$864,578	$(71,319)	$793,259	$691,806	$(35,908)	$655,898	$629,133	$(17,471)	$611,662

Tallgrass Equity Adjusted EBITDA:	Year Ended December 31, 2018 Total Adjusted EBITDA	2018 Inter-Segment	2018 External Adjusted EBITDA	2017 Total Adjusted EBITDA	2017 Inter-Segment	2017 External Adjusted EBITDA	2016 Total Adjusted EBITDA	2016 Inter-Segment	2016 External Adjusted EBITDA
				(in thousands)					
Natural Gas Transportation	$377,224	$(4,251)	$372,973	$180,978	$(2,176)	$178,802	$ 75,029	$(1,633)	$ 73,396
Crude Oil Transportation	239,330	(8,147)	231,183	140,785	4,878	145,663	132,154	4,881	137,035
Gathering, Processing & Terminalling	59,203	12,398	71,601	16,083	(2,702)	13,381	4,078	(3,248)	830
Corporate and Other	(21,321)	—	(21,321)	(37,591)	—	(37,591)	(2,142)	—	(2,142)
Reconciliation to Net Income:									
Add:									
Equity in earnings of unconsolidated investments [1]			237,197			66,922			15,287
Gain (loss) on disposal of assets[1]			4,630			189			(526)
Non-cash gain (loss) related to derivative instruments [1]			3,340			(64)			(650)
Gain on remeasurement of unconsolidated investment [1]			—			2,744			—
Less:									
Interest expense, net[1]			(95,465)			(29,403)			(16,632)
Depreciation and amortization expense [1]			(74,998)			(26,131)			(25,567)
Distributions from unconsolidated investments [1]			(302,364)			(86,551)			(22,085)
Non-cash compensation expense [1]			(8,634)			(2,682)			(1,862)
Deficiency payments, net [1]			(14,443)			(7,701)			(9,672)
Loss on debt retirement			(2,245)			—			—
Deferred income tax expense			(55,709)			(208,458)			(17,741)
Net income attributable to Exchange Right Holders			(208,618)			(137,849)			(95,882)
Net income (loss) attributable to TGE			$137,127			$(128,729)			$ 33,789

(1) Net of noncontrolling interest associated with less than wholly-owned subsidiaries of Tallgrass Equity.

Capital Expenditures:	Year Ended December 31, 2018	2017	2016
		(in thousands)	
Natural Gas Transportation	$ 112,529	$ 16,705	$ 28,475
Crude Oil Transportation	65,745	57,022	29,893
Gathering, Processing & Terminalling	185,732	71,417	26,123
Corporate and Other	4,867	—	—
Total capital expenditures	$ 368,873	$ 145,144	$ 84,491

Unconsolidated Investments:	December 31, 2018	December 31, 2017
	(in thousands)	
Natural Gas Transportation	$ 1,794,987	$ 895,873
Crude Oil Transportation	35,467	—
Gathering, Processing & Terminalling	31,232	13,658
Total unconsolidated investments	$ 1,861,686	$ 909,531

Assets:	December 31, 2018	December 31, 2017
	(in thousands)	
Natural Gas Transportation	$ 2,606,696	$ 1,606,666
Crude Oil Transportation	1,423,740	1,407,758
Gathering, Processing & Terminalling	1,522,559	943,340
Corporate and Other	340,514	334,249
Total assets	$ 5,893,509	$ 4,292,013

21. Selected Quarterly Financial Data (Unaudited)

The following tables summarize our unaudited quarterly financial data for 2018 and 2017:

	Quarter Ended 2018 First	Second	Third	Fourth
	(in thousands, except per unit amounts)			
Total revenues	$ 179,094	$ 193,589	$ 200,320	$ 220,256
Operating income	$ 81,913	$ 79,275	$ 90,084	$ 99,359
Net income	$ 114,313	$ 109,701	$ 118,712	$ 124,945
Net income allocable to noncontrolling interests	$ (97,578)	$ (108,638)	$ (59,162)	$ (65,166)
Net income attributable to TGE	$ 16,735	$ 1,063	$ 59,550	$ 59,779
Basic net income per Class A Share	$ 0.29	$ 0.02	$ 0.38	$ 0.38
Diluted net income per Class A Share	$ 0.29	$ 0.02	$ 0.38	$ 0.38

During the second quarter of 2018, we recognized increased deferred income tax expense as a result of our increased ownership in TEP due to the TEP Merger and the resulting increase in income allocated to TGE.

	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	$ 63,226	$ 66,944	$ 74,003	$ 67,674
Net income	$ 67,238	$ 79,167	$ 170,777	$ (93,197)
Net income allocable to noncontrolling interests	$ (55,209)	$ (70,414)	$ (154,911)	$ (72,180)
Net income (loss) attributable to TGE	$ 12,029	$ 8,753	$ 15,866	$ (165,377)
Basic net income (loss) per Class A Share	$ 0.21	$ 0.15	$ 0.27	$ (2.85)
Diluted net income (loss) per Class A Share	$ 0.21	$ 0.15	$ 0.27	$ (2.85)

During the third quarter of 2017, we recognized equity in earnings relating to our proportionate share of the Ultra settlement discussed in Note 19 – *Legal and Environmental Matters.* During the fourth quarter of 2017, we remeasured our deferred tax asset based on the new tax rates as a result of the federal rate change under the TCJA signed into law on December 22, 2017, resulting in an increase to our tax provision. For additional information, see Note 17 – *Income Taxes.*

22. Subsequent Events

Powder River Gateway

In January 2019, we closed on an expansion of our joint venture with Silver Creek. Effective January 1, 2019, we own a 51% membership interest in Powder River Gateway, which owns the Iron Horse Pipeline, the PRE Pipeline, and crude oil terminal facilities in Guernsey, Wyoming. For additional information, see Note 3 – *Acquisitions and Dispositions*.

Blackstone Acquisition

On January 31, 2019, we announced that BIP had entered into a definitive purchase agreement with Kelso, EMG, and Tallgrass KC pursuant to which BIP will acquire 100% of the membership interests in our general partner and an approximate 44% economic interest in us. Subject to customary closing conditions, the Blackstone Acquisition is expected to close within the first quarter of 2019.

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, 2018, 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, 2018, 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. Based on this assessment and those criteria, management determined that we maintained effective internal control over financial reporting as of December 31, 2018.

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, 2018, 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, 2018 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, LP

Our general partner's board of directors and executive officers manage our operations and activities. Our general partner is not elected by our Class A shareholders and will not be subject to re-election in the future. Directors of our general partner oversee our operations. Class A shareholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operations.

Unlike shareholders in a publicly traded corporation, our shareholders are not entitled to select our general partner or elect the members of the board of directors of our general partner. Tallgrass Energy Holdings is the sole owner of our general partner and has the right to appoint the entire board of directors of our general partner, including our independent directors. As of February 8, 2019, EMG, Kelso and Tallgrass KC own, in the aggregate, approximately 100% of the outstanding membership interests in Tallgrass Energy Holdings. Following consummation of the Blackstone Acquisition, the membership interests in our general partner will be owned by BIP. As of February 8, 2019, all the executive officers and certain of the directors of our general partner are also officers and/or directors of Tallgrass Energy Holdings.

As of December 31, 2018, 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, Thomas A. Gerke, Roy N. Cook and Terrance D. Towner. 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, 2018, the audit committee of the board of directors of our general partner had four 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 TEP GP, Tallgrass Equity, 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 in connection with the management of our business, but Tallgrass Equity reimburses our general partner for all expenses it incurs and payments it makes on our behalf pursuant to our partnership agreement. In addition, Tallgrass Equity reimburses Tallgrass Energy Holdings and its affiliates for all expenses it incurs and payments it makes on our behalf pursuant to the TGE Omnibus Agreement, including the costs of employee and director compensation and benefits as well as the cost of the provision of certain corporate, general and administrative services in each case to the extent properly allocable to us. Any direct expenses associated with being a separate publicly traded entity are borne by Tallgrass Equity. Neither our partnership agreement nor the TGE Omnibus Agreement limits the amount of expenses for which our general partner, Tallgrass Energy Holdings and their respective affiliates may be reimbursed. For more information, see "*Certain Relationships and Related Party Transactions, and Director Independence-Omnibus Agreement.*"

Directors and Executive Officers of Our General Partner

The following table sets forth certain information with respect to the executive officers and directors of our general partner as of February 8, 2019.

Name	Age	Position with Our General Partner
David G. Dehaemers, Jr.	58	President, Chief Executive Officer and Director
William R. Moler	53	Executive Vice President, Chief Operating Officer and Director
Gary J. Brauchle	45	Executive Vice President and Chief Financial Officer
Christopher R. Jones	42	Executive Vice President, General Counsel and Secretary
Gary D. Watkins	46	Vice President and Chief Accounting Officer
Frank J. Loverro	49	Director
Stanley de J. Osborne	48	Director
Jeffrey A. Ball	44	Director
John T. Raymond	48	Director
Thomas A. Gerke	62	Director
Roy N. Cook	61	Director
Terrance D. Towner	60	Director

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

David G. Dehaemers, Jr. has been a director and the President and Chief Executive Officer of our general partner since February 2015. Mr. Dehaemers has served as the President and Chief Executive Officer of TEP GP and Tallgrass Equity since February 2013 and as a director and the President and Chief Executive Officer of Tallgrass Energy Holdings since August 2012. Previously, Mr. Dehaemers served as a director of TEP GP from February 2013 to June 2018. 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.

William R. Moler has been a director, Executive Vice President and Chief Operating Officer of our general partner since February 2015. Mr. Moler has also served as Executive Vice President and Chief Operating Officer of TEP GP and Tallgrass Equity since February 2013 and as a director, Executive Vice President and Chief Operating Officer of Tallgrass Energy Holdings since October 2012. Previously, Mr. Moler served as a director of TEP GP from February 2013 to June 2018. 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.

Gary J. Brauchle has been Executive Vice President and Chief Financial Officer of our general partner since February 2015. Mr. Brauchle has also served as Executive Vice President and Chief Financial Officer of TEP GP and 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 Executive Vice President, General Counsel and Secretary of our general partner since February 2018. Mr. Jones has also served as Executive Vice President, General Counsel and Secretary of TEP GP and Tallgrass Energy Holdings since February 2018. Previously, Mr. Jones served as Vice President, General Counsel and Secretary of our general partner, TEP GP and Tallgrass Energy Holdings from May 2016 to February 2018 and was an Assistant General Counsel at Tallgrass from October 2012 to May 2016. 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 February 2015. Mr. Watkins has also served as Vice President and Chief Accounting Officer of TEP GP since April 2014 and of Tallgrass Equity and 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 2015 and as a director of Tallgrass Energy Holdings since August 2012. Previously, Mr. Loverro served as a director of TEP GP from February 2013 to June 2018. 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 Delphin Shipping 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 board of directors of our general partner.

Stanley de J. Osborne has served as a director of our general partner since February 2015 and as a director of Tallgrass Energy Holdings since August 2012. Previously, Mr. Osborne served as a director of TEP GP from February 2013 to June 2018. 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 LBM Acquisition, LLC, Southern Carlson and Traxys S.a.r.l. 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 board of directors of our general partner.

Jeffrey A. Ball has served as a director of our general partner since February 2015 and as the Chairman of the audit committee of our general partner since April 2015. Further, Mr. Ball has served as a director of Tallgrass Energy Holdings since August 2012. Previously, Mr. Ball served as a director of TEP GP from May 2013 to June 2018 and as the Chairman of the audit committee of TEP GP from May 2013 to June 2018. 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, Ascent Resources, LLC, Sable Permian Resources, 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 board of directors of our general partner.

John T. Raymond has served as a director of our general partner since February 2015 and as a director of Tallgrass Energy Holdings since August 2012. Previously, Mr. Raymond served as a director of TEP GP from February 2013 to June 2018. Mr. Raymond is an owner and founder of The Energy & Minerals Group. EMG is a diversified natural resource private equity fund manager with approximately $16.0 billion of regulatory assets under management (RAUM) as of September 30, 2018. EMG has allocated approximately $11.0 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 board of directors of our general partner.

Thomas A. Gerke has served as a director of our general partner and as a member of the audit committee of our general partner since August 2015. Mr. Gerke has served as the General Counsel and Chief Administrative Officer at H&R Block, a global consumer tax services provider since May 2016 and prior to that starting in January 2012, he served as Chief Legal Officer. In addition, in 2017 while H&R Block went through a CEO transition, Mr. Gerke served as interim President and Chief Executive Officer from August 1, 2017 to October 8, 2017. Prior to joining H&R Block, from January 2011 to April 2011, Mr. Gerke served as Executive Vice President, General Counsel and Secretary of YRC Worldwide, a leading transportation service provider. From July 2009 to December 2010, Mr. Gerke served as Executive Vice Chairman of CenturyLink, a Fortune 500 integrated communications business. From December 2007 to June 2009, he served as President and Chief Executive Officer at Embarq, then a Fortune 500 integrated communications business. He also held the position of Executive Vice President and General Counsel, Law and External Affairs at Embarq from May 2006 to December 2007. From October 1994 through May 2006, Mr. Gerke held several executive and legal positions with Sprint, serving as Executive Vice President and General Counsel for over two years. Mr. Gerke currently serves as a member of the board of directors at Consolidated Communications Holdings, Inc. (NASDAQ: CNSL). He is also a former member of the boards of CenturyLink, Embarq and United States Telecom Association. In addition, he is a former member of the board of trustees for Rockhurst University and the Kansas City Local Investment Commission (LINC). Mr. Gerke earned his Bachelor of Science degree in Business Administration from the University of Missouri in Columbia, his Masters of Business Administration degree from Rockhurst University, and his Juris Doctorate from the University of Missouri School of Law in Kansas City. We believe that Mr. Gerke's leadership roles and board experience at a number of Fortune 500 and other large public companies, as well as his legal acumen and background outside of the energy industry, provides a valuable resource to the board of directors of our general partner.

Roy N. Cook has served as a director of our general partner and as a member of the audit committee of our general partner since September 2018. Previously, Mr. Cook served as a director of TEP GP from September 2013 to June 2018 and as a member of the audit committee of TEP GP from December 2017 to June 2018. 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.

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 September 2018. Previously, Mr. Towner served as a director of TEP GP and as a member of the audit committee of TEP GP from August 2013 to June 2018. Mr. Towner currently serves as the Executive Chairman of Jaguar Management Inc. and its affiliates, which makes direct investments in and provides advisory services to various private companies and clients. Mr. Towner is also a director of Base, Inc., Cando Rail Services Holdings, Inc., West Memphis Transload, West Memphis Base

Railroad and SilverCreek RCM. Prior to joining Jaguar Management, Inc. in November 2018, Mr. Towner provided business advisory services. 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.

Audit Committee

The board of directors of our general partner has a standing audit committee which is currently comprised of four directors, Jeffrey A. Ball, Thomas A. Gerke, Roy N. Cook, and Terrance D. Towner. 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 us and our general partner or the owners of our general partner. 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 the 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.

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 shareholders. Any shareholder 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, 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 Class A shares, Class B shares and other equity securities. Officers, directors and greater than 10% shareholders 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 2015. Our general partner did not accrue any obligations with respect to management incentive or retirement benefits for its directors and executive officers until after our initial public offering in May 2015. 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 Tallgrass Management, LLC ("Tallgrass Management"). Prior to July 1, 2018, Tallgrass Management was a wholly-owned subsidiary of Tallgrass Energy Holdings. Effective July 1, 2018, Tallgrass Management was contributed to Tallgrass Equity in connection with the TEP Merger. As a result, the costs of employer and director compensation and benefits are now incurred directly by Tallgrass Equity.

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 controls our general partner. Prior to July 1, 2018, we reimbursed Tallgrass Energy Holdings and its affiliates for all salaries, benefits and other compensation expenses for employees of Tallgrass Management (including the Named Executive Officers) to the extent such employees provided services to us pursuant to an allocation agreed upon between our general partner and Tallgrass Energy Holdings under the terms of the TGE 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 TGE.

Philosophy and Objectives

Since our initial public offering in May 2015, 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 Class A shareholders, 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 Class A shareholders, and to reward success in reaching such goals.

We use three primary elements of compensation to fulfill that design: salary, bonuses and long-term equity incentive awards. 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' 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 dividends to our Class A shareholders 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 midstream energy companies, but are moderate relative to energy industry competitors for people with similar roles and responsibilities.

Bonuses. Our bonuses are annual discretionary bonuses in which all of our current Named Executive Officers potentially participate. Our bonuses to Named Executive Officers generally consist of a cash bonus. In 2018, Mr. Brauchle, Mr. Moler and Mr. Jones were granted awards under the Legacy LTIP (as defined below) as an additional component of their 2018 bonus. These awards were granted on January 31, 2019 and vested immediately. The recipients of these awards will receive the Class A shares as a result of the vesting on January 31, 2020.

Awards under Long-Term Incentive Plans. We have two long-term incentive plans. The Tallgrass Energy GP, LLC Long-Term Incentive Plan (f/k/a the TEGP Management, LLC Long-Term Incentive Plan), was originally adopted by our general partner effective as of May 1, 2015, and was amended and restated effective August 2, 2018 (as amended, the "TGE LTIP"). In addition, the Tallgrass MLP GP, LLC Long-Term Incentive Plan was originally adopted by TEP GP effective as of May 13, 2013, and was amended and restated effective August 2, 2018 (as amended, the "Legacy LTIP" and together with the TGE LTIP, the "Plans"). In connection with the completion of the TEP Merger effective June 30, 2018, discussed in Note 1 – *Description of Business*, the Legacy LTIP was assumed by our general partner and TEP's outstanding equity participation units were converted to equity participation shares at a ratio of 2.0 equity participation shares for each outstanding TEP equity participation unit.

Awards under the Plans may consist of, among others, unrestricted shares, restricted shares, equity participation shares, options and share appreciation rights which may be granted to (i) the employees of our general partner and its affiliates who perform services for us, (ii) the non-employee directors of our general partner and (iii) the consultants who perform services for us (such awards, the "LTIP Awards"). Historically, we have used equity participation share awards under the Plans to encourage and reward timely achievement of certain events or dividend levels and align the long-term interests of our Named Executive Officers with those of our Class A shareholders. An equity participation share is the right to receive, upon the satisfaction of vesting criteria specified in the grant, a Class A share. Equity participation share awards under the Plans have been, and we expect will continue to be, the primary long-term equity incentive provided to our Named Executive Officers and appropriately incentivizes our Named Executive Officers to seek stable dividend growth.

Vesting Conditions. The vesting conditions applicable to the equity participation shares held by Named Executive Officers that are outstanding under the Plans can generally be divided into the following categories:

- The first category of awards was originally granted by TEP 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 TEP 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 vests 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, and the first half of the awards in this category vested on May 13, 2018. The remaining half will vest on May 13, 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 shares in this category. The Blackstone Acquisition constitutes a change of control with respect to the awards in this category and as a result, any outstanding awards in this category will vest upon consummation of the Blackstone Acquisition.
- The second category of awards was granted by TGE in 2015 to Mr. Jones and to Mr. Watkins. 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 TGE pays a regular quarterly dividend of at least \$0.35 on each outstanding Class A share (the "TGE Dividend Achievement Date") or May 12, 2019. The TGE Dividend Achievement Date was met upon payment of the \$0.3550 dividend 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. The Blackstone Acquisition constitutes a change of control with respect to the awards in this category and as a result, any outstanding awards in this category will vest upon consummation of the Blackstone Acquisition.
- The third category of awards was originally granted by TEP 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 shares in this category. The Blackstone Acquisition constitutes a change of control with respect to the awards in this category and as a result, any outstanding awards in this category will vest upon consummation of the Blackstone Acquisition.

- The fourth category of awards was originally granted by TEP 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 TGE's regular quarterly distributions, based upon the regular quarterly distribution paid by TGE on, or immediately prior to, such date is at least 5% over an annualized distribution rate of $1.67 per TGE Class A share, as determined by the board of directors of our general partner. If such date has not occurred by August 2, 2024, such equity participation shares 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 shares in this category. The 2017 Grants do not vest solely as a result of the consummation of the Blackstone Acquisition. See *"Potential Payments upon Termination or Change-in-Control"* for a description of the conditions that would accelerate vesting of the 2017 Grants.
- The fifth category of awards was originally granted by TEP in February 2018 and will vest on January 1, 2020 as long as the employee satisfies the continuing service requirement set for in the applicable award agreement. Mr. Brauchle, Mr. Moler, and Mr. Jones are the only Named Executive Officers that were granted equity participation shares in this category. The Blackstone Acquisition constitutes a change of control with respect to the awards in this category and as a result, any outstanding awards in this category will vest upon consummation of the Blackstone Acquisition.
- The sixth category of awards was granted by TGE in October 2018 (the "2018 Grants") and will vest on the earliest date on or after November 1, 2022, on which the average compounded annual distribution growth rate, based upon the regular quarterly distribution paid by TGE on, or immediately prior to, such date is at least 5% over an annualized distribution rate of $1.99 per TGE Class A share, as determined by the board of directors of our general partner. If such date has not occurred by October 19, 2025, such equity participation shares 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 shares in this category. The 2018 Grants do not vest solely as a result of the consummation of the Blackstone Acquisition. See *"Potential Payments upon Termination or Change-in-Control"* for a description of the conditions that would accelerate vesting of the 2018 Grants.

Relation of Compensation Elements to Compensation Objectives

Our compensation program is designed to motivate, reward and retain our Named Executive Officers. Bonuses serve as a near-term motivation and reward for achieving positive short-term results, such as meeting specified dividend 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 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 Class A shareholders, (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. One of the primary measures of our performance is our ability to enhance the ability of our assets to generate cash available for dividends that we can use to increase quarterly dividends to our Class A shareholders. In the period since our initial public offering through December 31, 2018, our compounded annual dividend growth rate is 48%. This dividend growth has, in part, supported our decision to pay bonuses to our Named Executive Officers related to 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 Bonuses. Annual discretionary bonuses are determined based on our performance relative to our annual budget, our dividend 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, cash available for dividend, dividend coverage, and growth in the annualized quarterly dividend level per Class A share relative to annual growth targets. We also compare our market performance relative to our peers and major indices. Our primary performance metric is our ability to generate increasing and sustainable cash dividends to our Class A shareholders. 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 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 2018

In connection with the announcement of the TEP Merger in March 2018, we established the following financial performance objectives for 2018:

- Adjusted EBITDA of $755 - $835 million for the year ended December 31, 2018;
- Maintenance capital of $20 - 30 million for the year ended December 31, 2018;
- Dividend coverage of greater than 1.20x for the year ended December 31, 2018; and
- Growth of approximately 38 - 42% in our annualized dividend rate for the calendar year 2018.

We met or exceeded all these goals:

- Our Adjusted EBITDA for the year ended December 31, 2018 was approximately $860.4 million;
- Our maintenance capital for the year ended December 31, 2018 was approximately $21 million;
- Our dividend coverage for the year ended December 31, 2018 was approximately 1.26x; and
- Our dividends on Class A shares in the fourth quarter of 2018 represented a 41.5% increase from the fourth quarter of 2017.

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 execution of the Merger Agreement and successful completion of the TEP Merger with the expected benefits of streamlining our corporate structure, lowering our cost of capital, and broadening our investor appeal;

- The acquisitions from Tallgrass Development of an additional 25.01% membership interest in Rockies Express and the remaining 2% membership interest in Pony Express in February 2018;
- Third-party acquisitions in 2018, including the acquisition of a 38% membership interest in Deeprock North in January 2018, a 100% membership interest in Buckhorn Energy Services, LLC and Buckhorn SWD Solutions, LLC in January 2018, a 51% membership interest in Pawnee Terminal in April 2018, and a 100% membership interest in NGL Water Solutions Bakken, LLC in November 2018;
- The assignment by Fitch Ratings of investment grade ratings to TEP and Rockies Express in September 2018;
- The amendment of the TEP revolving credit facility in July 2018, increasing the available amount from $1.75 billion to $2.25 billion and permitting the repayment of the Tallgrass Equity revolving credit facility; and
- The senior note offerings of the 2023 Notes in an aggregate principal amount of $500 million in September 2018.

For 2018, the elements of compensation were applied as described below.

Salary. In 2018, we did not implement material salary increases for Mr. Dehaemers, Mr. Brauchle, or Mr. Moler. Mr. Jones and Mr. Watkins received salary increases of approximately 10% over 2017.

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 2018 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. Each of our Named Executive Officers, with the exception of Mr. Dehaemers, received grants under the Plans in 2018. As noted below, we believe the substantial direct and indirect equity interests held by our management team, including our Named Executive Officers, in TGE, Tallgrass Energy Holdings and Tallgrass Equity aligns their interests with those of our Class A shareholders, and is taken into account when considering the level of equity incentives 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 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 TGE. Based on the closing price of Class A shares on February 6, 2019, 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 2018. We believe that the substantial direct and indirect equity interests held by our management team in TGE and Tallgrass Energy Holdings further aligns their interests with those of our Class A shareholders, and is taken into account when considering the level of equity incentives granted to our Named Executive Officers under our compensation programs.

Equity Ownership in TGE, Tallgrass Energy Holdings and Tallgrass Equity. Each of our Named Executive Officers beneficially own Class A shares in TGE and some of our Named Executive Officers indirectly own equity interests in Tallgrass Energy Holdings, Tallgrass Equity and TGE through Tallgrass KC, an entity controlled by Mr. Dehaemers. As of February 6, 2019, our Named Executive Officers beneficially owned, in the aggregate, 3,544,643 of TGE's Class A shares (excluding any unvested LTIP Awards). As of February 6, 2019, Tallgrass KC owned 29,416,692 Class B Shares in TGE and 29,416,692 Units in Tallgrass Equity, representing an approximate 10.50% ownership interest in TGE and Tallgrass Equity, respectively. In addition, as of February 6, 2019, Mr. Dehaemers controlled 281,171 Class B Shares in TGE and 281,171 Units in Tallgrass Equity through the David G. Dehaemers, Jr. Revocable Trust, dated April 26, 2006.

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 share grants to our Named Executive Officers other than the 2017 Grants and 2018 Grants include accelerated vesting triggered upon a change of control, as defined in the respective award agreements. The Blackstone Acquisition constitutes a change of control with respect to these equity participation shares and as a result, any outstanding equity participation shares to our Named Executive Officers other than the 2017 Grants and the 2018 Grants will vest upon consummation of the Blackstone Acquisition. Although the Blackstone Acquisition will constitute a qualifying transaction under the 2017 Grants and the 2018 Grants, vesting under such awards will not accelerate until one of the subsequent conditions described below occurs.

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 or certain of its affiliates, or (ii) (A) Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner or certain of its affiliates, and (B) the Named Executive Officer is thereafter terminated without cause.

The 2018 Grants to Mr. Jones include accelerated vesting if either (i) both (A) a qualifying transaction occurs, as defined in the award agreement, and (B) in connection with or within 12 months following such qualifying transaction, Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner or certain of its affiliates, or (ii) (A) Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner or certain of its affiliates, and (B) within 2 years after the occurrence of such event, Mr. Jones is terminated without cause. The 2018 Grants to Mr. Watkins include accelerated vesting if either (i) both (A) a qualifying transaction occurs, and (B) in connection with or within 12 months following such qualifying transaction, Mr. Dehaemers, Mr. Moler, Mr. Brauchle or Mr. Jones cease to comprise at least one of the roles of Chief Executive Officer, Chief Operating Officer, Chief Financial Officer or General Counsel of our general partner or certain of its affiliates, or (ii) (A) Mr. Dehaemers, Mr. Moler, Mr. Brauchle or Mr. Jones cease to comprise at least one of the roles of Chief Executive Officer, Chief Operating Officer, Chief Financial Officer or General Counsel of our general partner or certain of its affiliates, and (B) within 2 years after the occurrence of such event, Mr. Watkins is 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 to Mr. Jones and Mr. Watkins and the 2018 Grants to Mr. Jones, if Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner or certain of its 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, in order to achieve the dividend growth performance hurdles.

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 2018 (the "Named Executive Officers") for services rendered to all Tallgrass-related entities, including TEP, TGE, Tallgrass Management and Tallgrass Development, for the fiscal years ending December 31, 2018, 2017, and 2016.

	Year	Salary (1)	Cash Bonus (2)	Equity Awards (3)	All Other Compensation (4)	Total
David G. Dehaemers, Jr.	2018	$ 300,000	$1,000,000	$ —	$ 28,652	$ 1,328,652
President, Chief Executive	2017	$ 300,000	$1,000,739	$ —	$ 28,152	$ 1,328,891
Officer and Director	2016	$ 300,000	$ 651,467	$ —	$ 27,544	$ 979,011
William R. Moler	2018	$ 300,000	$ 500,000	$ 951,328	$ 28,652	$ 1,779,980
Executive Vice President, Chief	2017	$ 300,000	$ 400,943	$ —	$ 28,152	$ 729,095
Operating Officer and Director	2016	$ 300,000	$ 576,468	$ —	$ 24,544	$ 901,012
Gary J. Brauchle	2018	$ 300,000	$ 500,000	$ 710,854	$ 28,459	$ 1,539,313
Executive Vice President and	2017	$ 299,712	$ 750,942	$ —	$ 27,955	$ 1,078,609
Chief Financial Officer	2016	$ 294,904	$ 576,144	$ —	$ 27,537	$ 898,585
Christopher R. Jones	2018	$ 297,116	$ 500,000	$ 3,821,254	$ 28,644	$ 4,647,014
Executive Vice President,	2017	$ 271,569	$ 750,942	$ 3,545,100	$ 27,686	$ 4,595,297
General Counsel and Secretary	2016	$ 240,068	$ 426,467	$ 69,836	$ 24,486	$ 760,857
Gary D. Watkins	2018	$ 247,116	$ 250,000	$ 1,209,600	$ 25,664	$ 1,732,380
Vice President and	2017	$ 224,922	$ 248,435	$ 1,378,650	$ 23,356	$ 1,875,363
Chief Accounting Officer	2016	$ 222,975	$ 201,470	$ 69,836	$ 23,081	$ 517,362

(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 cash bonuses paid in 2019, 2018 and 2017 based on performance in 2018, 2017 and 2016, respectively, as well as a bonus of $500 after tax that was paid to all employees in 2017, and a bonus of $1,000 after tax that was paid to all employees in 2016.

(3) The amounts in this column include equity participation shares granted pursuant to the Plans. Each of our Named Executive Officers, with the exception of Mr. Dehaemers, received grants under the Plans in 2018. In addition, Mr. Moler, Mr. Brauchle, and Mr. Jones each received grants in January 2019 as a component of their 2018 bonuses. Mr. Jones and Mr. Watkins were the only Named Executive Officers to receive grants under the Plans during 2016 and 2017. These amounts represent the aggregate grant date fair value determined in accordance with ASC Topic 718 for equity participation units, or EPUs, granted under the Legacy LTIP prior to June 30, 2018 and equity participation shares, or EPSs granted under the Plans. 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 TGE'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 16 – *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 $27,500 for Mr. Dehaemers, $27,500 for Mr. Moler, $27,307 for Mr. Brauchle, $27,500 for Mr. Jones, and $24,712 for Mr. Watkins for the year ended December 31, 2018; $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; and $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 the dollar value of premiums paid for group life, accidental death and dismemberment insurance.

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. 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, 2018 through December 31, 2018. We determined that our Chief Executive Officer had annual total compensation of $1,328,652, 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 $96,979. Therefore, our Chief Executive Officer's annual total compensation is 13.7 times that of the median of the annual total compensation of all employees of Tallgrass Management.

Grants of Plan-Based Awards Table

The following table provides information concerning each grant of an award made to a Named Executive Officer during 2018 under the Plans.

	Grant Type	Grant Date	Number of Shares or Units		Grant Date Fair Value of Awards[(1)]
Gary J. Brauchle					
Executive Vice President and	TEP Equity Participation Units	2/14/18	6,700	(2)	$ 30.83
Chief Financial Officer	TGE Equity Participation Shares	—	—		$ —
William R. Moler					
Executive Vice President, Chief	TEP Equity Participation Units	2/14/18	14,500	(2)	$ 30.83
Operating Officer and Director	TGE Equity Participation Shares	—	—		$ —
Christopher R. Jones					
Executive Vice President, General	TEP Equity Participation Units	2/14/18	6,700	(2)	$ 30.83
Counsel and Secretary	TGE Equity Participation Shares	10/19/18	180,000	(3)	$ 17.28
Gary D. Watkins					
Vice President and	TEP Equity Participation Units	—	—		$ —
Chief Accounting Officer	TGE Equity Participation Shares	10/19/18	70,000	(3)	$ 17.28

(1) 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 Legacy LTIP prior to June 30, 2018 and equity participation shares, or EPSs, granted under the Plans. 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 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 TGE'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 16 – *Equity-Based Compensation*. These amounts do not correspond to the actual value that will be recognized by the executive.

(2) Vesting of the EPUs will occur on January 1, 2020 as long as the employee satisfies the continuing service requirement set forth in the applicable award agreement. These awards were converted to EPSs effective June 30, 2018 at a ratio of 2.0 EPSs for each outstanding EPU. The Blackstone Acquisition constitutes a change of control with respect to these EPSs and as a result, any outstanding EPSs under these awards will vest upon consummation of the Blackstone Acquisition.

(3) Vesting of the EPSs will occur on the earliest date on or after November 1, 2022, on which the average compounded annual distribution growth rate, based upon the regular quarterly distribution paid by TGE on, or immediately prior to, such date is at least 5% over an annualized distribution rate of $1.99 per TGE Class A share, as determined by the board of directors of our general partner. If such date has not occurred by October 19, 2025, such EPSs will expire and terminate and no vesting will occur. These EPSs do not vest solely as a result of the consummation of the Blackstone Acquisition. See *"Potential Payments upon Termination or Change-in-Control"* for a description of the conditions that would accelerate vesting of these EPSs.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Award Table

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

Outstanding Equity Awards at Fiscal Year-End

Effective June 30, 2018, all outstanding TEP equity participation units under the Legacy LTIP were converted to equity participation shares at a ratio of 2.0 equity participation shares for each outstanding TEP equity participation unit. The following table reflects all outstanding equity awards of our named executive officers as of December 31, 2018.

	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 [(2)]	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	29,000 [(3)]	$ 705,860	—	$ —
Gary J. Brauchle	13,400 [(4)]	$ 326,156	—	$ —
Christopher R. Jones	418,200 [(5)]	$ 10,178,988	—	$ —
Gary D. Watkins	185,400 [(6)]	$ 4,512,636	—	$ —

(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 Class A Shares.

(2) Reflects the closing price of $24.34 per Class A share at December 31, 2018.

(3) Mr. Moler holds 29,000 equity participation shares issued under the fifth category of awards described under *"Elements of Compensation"* above.

(4) Mr. Brauchle holds 13,400 equity participation shares issued under the fifth category of awards described under *"Elements of Compensation"* above.

(5) Mr. Jones holds 5,800, 35,000, 4,000, 180,000, 13,400, and 180,000 equity participation shares issued under the first, second, third, fourth, fifth, and sixth categories, respectively, as described under *"Elements of Compensation"* above.

(6) Mr. Watkins holds 6,400, 35,000, 4,000, 70,000, and 70,000 equity participation shares issued under the first, second, third, fourth, and sixth categories, respectively, as described under *"Elements of Compensation"* above.

Vested LTIP Awards

The following table sets forth certain information regarding the vesting of LTIP Awards held by the Named Executive Officers granted under the Legacy LTIP prior to the June 30, 2018 effective date of the TEP Merger. No LTIP Awards held by the Named Executive Officers under the TGE LTIP vested during 2018 and no LTIP Awards held by the Named Executive Officers under the Legacy LTIP vested after June 30, 2018.

	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*	—	$ —
Gary J. Brauchle *Executive Vice President and Chief Financial Officer*	—	$ —
Christopher R. Jones *Executive Vice President, General Counsel and Secretary*	2,900	$ 123,801
Gary D. Watkins *Vice President and Chief Accounting Officer*	3,200	$ 136,608

(1) Represents the gross number of EPUs that vested during the year ended December 31, 2018. The actual number of TEP common units 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 TEP 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 ($42.69) of TEP's common units on the date they vested (May 13, 2018) 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 TEP's general partner, 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 TGE 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, if curable, is not cured within 30 days of receiving a written notice of such gross neglect or gross or willful misconduct; (iv) Mr. Dehaemers' willful failure or refusal to carry out the reasonable and lawful instructions of the board of managers of Tallgrass Energy Holdings, and, in each case, such failure or refusal has continued for a period of 30 calendar days following written notice; (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 limited liability company agreements of Tallgrass Energy Holdings, our general partner, Tallgrass Equity and TEP GP, including willfully causing any applicable Tallgrass entity to take any material action prohibited by such organizational documents, that Mr. Dehaemers failed to cure, if curable, within 30 days following written notice thereof, specifically identifying such willful and material breach.
- "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 and 2018 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 Legacy LTIP Awards and TGE LTIP Awards held by our Named Executive Officers other than the 2017 Grants and 2018 Grants typically provide for acceleration of vesting in connection with a change in control. The LTIP Awards held by our Named Executive Officers other than the 2017 Grants and 2018 Grants vest and/or become exercisable in full upon a "change in control" of us or our general partner. The Blackstone Acquisition constitutes a change of control with respect to these LTIP Awards and as a result, any outstanding LTIP Awards to our Named Executive Officers other than the 2017 Grants and the 2018 Grants will vest upon consummation of the Blackstone Acquisition.

Under the Plans, "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 our general partner or (B) the general partner interests in TGE;
- the limited partners of TGE approve, in one or a series of transactions, a plan of complete liquidation of TGE; or
- the sale or other disposition by TGE of all or substantially all of its assets in one or more transactions to any person other than our general partner an affiliate of our general partner.

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 or certain of its affiliates, or (ii) (A) Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner or certain of its 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 TEP's general partner, the ownership of 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;

- TEP's 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 TEP's general partner and its affiliates.

The 2017 Grants do not vest solely as a result of the consummation of the Blackstone Acquisition.

The 2018 Grants to Mr. Jones include accelerated vesting if either (i) both (A) a qualifying transaction occurs, and (B) in connection with or within 12 months following such qualifying transaction, Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner or certain of its affiliates, or (ii) (A) Mr. Dehaemers ceases to be the Chief Executive Officer of our general partner or certain of its affiliates, and (B) within 2 years after the occurrence of such event, Mr. Jones is terminated without cause.

The 2018 Grants to Mr. Watkins include accelerated vesting if either (i) both (A) a qualifying transaction occurs, and (B) in connection with or within 12 months following such qualifying transaction, Mr. Dehaemers, Mr. Moler, Mr. Brauchle or Mr. Jones cease to comprise at least one of the roles of Chief Executive Officer, Chief Operating Officer, Chief Financial Officer or General Counsel of our general partner or certain of its affiliates, or (ii) (A) Mr. Dehaemers, Mr. Moler, Mr. Brauchle or Mr. Jones cease to comprise at least one of the roles of Chief Executive Officer, Chief Operating Officer, Chief Financial Officer or General Counsel of our general partner or certain of its affiliates, and (B) within 2 years after the occurrence of such event, Mr. Watkins is terminated without cause.

Under the award agreements for the 2018 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 more than 50% of the voting interests in our general partner, the ownership of more than 50% of the general partner interests in TGE, 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 TGE, whether through the ownership of voting rights, by contract, or otherwise, or if TGE becomes a corporation or limited liability company or if the limited partners of TGE become eligible to elect the members of the board of our general partner, the direct or indirect ability to appoint a majority of the board of directors of the corporation or limited liability company or the board of our general partner, as the case may be.
- TGE's limited partners approve, in one or a series of transactions, a plan of complete liquidation of TGE; or
- the sale or other disposition by TGE 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 2018 Grants do not vest solely as a result of the consummation of the Blackstone Acquisition.

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 Plans if a triggering change in control event described above occurred on December 31, 2018.

	Upon a Change in Control [1]
David G. Dehaemers, Jr.	$ —
William R. Moler	$ 705,860
Gary J. Brauchle	$ 326,156
Christopher R. Jones	$ 10,178,988
Gary D. Watkins	$ 4,512,636

(1) The stated value upon a change in control is computed by assuming that a triggering change of control event occurred on December 31, 2018 and multiplying the closing market price ($24.34) of the Class A shares on such date by the number of Class A 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 and 2018 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 LTIP Awards are forfeited without vesting, and (iii) the date such LTIP Awards expire. Each of the Named Executive Officers has signed a confidentiality agreement in connection with their employment by Tallgrass Management.

Compensation of TGE 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 2018, 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.

In addition, Mr. Cook and Mr. Towner received compensation during the year ended December 31, 2018 for their service on the TEP board of directors prior to the TEP Merger. Mr. Cook and Mr. Towner were appointed as directors of our general partner on September 7, 2018.

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 Plans.

The following table sets forth certain information with respect to our non-employee directors receiving cash compensation during the year ended December 31, 2018:

Name and Principal Position	Fees Earned	Equity Participation Share Awards [1]	Non-Equity Incentive Plan Compensation	Total
Thomas A. Gerke	$ 60,000	$ —	$ —	$ 60,000
Roy N. Cook	$ 105,000	$ 130,840	$ —	$ 235,840
Terrance D. Towner	$ 65,000	$ 130,840	$ —	$ 195,840
W. Curtis Koutelas [2]	$ 30,000	$ —	$ —	$ 30,000

(1) The amounts in this column include equity participation shares granted pursuant to the Plans. These amounts represent the aggregate grant date fair value determined in accordance with ASC Topic 718 for equity participation shares granted under the Plans. Pursuant to SEC rules, the amounts shown in the table above 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 EPSs are non-participating, therefore the grant date fair value is discounted from the grant date fair value of TGE'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 16 – *Equity-Based Compensation*. These amounts do not correspond to the actual value that will be recognized by the directors.

(2) Mr. Koutelas resigned from the board of directors of our general partner effective September 7, 2018.

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, 2018 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
Thomas A. Gerke
Roy N. Cook
Terrance D. Towner

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

Tallgrass Energy, LP

The following tables set forth certain information regarding the beneficial ownership of our Class A shares and Class B shares as of February 6, 2019 owned by:

- each person who is known to us to beneficially own more than 5% of the Class A shares (calculated in accordance with Rule 13d-3);
- the named executive officers of our general partner;
- each of the directors of our general partner; and
- all the directors and executive officers of our general partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more shareholders, as the case may be. The amounts and percentage of Class A shares and Class B shares beneficially owned are reported on the basis of SEC regulations 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 Class A shares and Class B shares shown as beneficially owned by them, subject to community property laws where applicable. Unless otherwise noted, the address of each beneficial owner named in the chart below is 4200 W. 115th Street, Suite 350, Leawood, Kansas 66211, Attn: General Counsel.

Name and Address of Beneficial Owner	Class A and Class B shares Beneficially Owned [1]	Percentage of Class A and Class B shares Beneficially Owned [2]	Combined Voting Power [3]
5% shareholders			
Entities affiliated with Kelso [4]	46,727,603	23.01%	16.67%
Entities affiliated with EMG [5]	46,386,232	22.88%	16.55%
Tallgrass KC [6]	29,416,692	15.83%	10.5%
OppenheimerFunds, Inc. [7]	26,697,437	17.08%	9.53%
Tortoise Capital Advisors, L.L.C. [8]	24,224,847	15.49%	8.64%
Kayne Anderson Capital Advisors, L.P. [9]	8,822,918	5.64%	3.15%
Salient Capital Advisors LLC [10]	7,847,848	5.02%	2.8%
Directors and named Executive officers:			
David G. Dehaemers, Jr. [11]	31,504,182	16.91%	11.24%
William R. Moler [12]	2,903,053	1.82%	1.04%
Gary J. Brauchle [13]	2,328,812	1.47%	*
Christopher R. Jones [14]	358,978	*	*
Gary D. Watkins	46,830	*	*
Frank J. Loverro [4]	46,727,603	23.01%	16.67%
Stanley de J. Osborne [4]	46,727,603	23.01%	16.67%
Jeffrey A. Ball	100,000	*	*
John T. Raymond [15]	46,833,283	23.1%	16.71%
Thomas A. Gerke	54,300	*	*
Roy N. Cook	116,165	*	*
Terrance D. Towner	53,000	*	*
All directors and executive officers of our general partner as a group (11 persons)	131,026,206	46.98%	46.75%

* Less than 1%.

(1) Pursuant to Rule 13d-3 under the Exchange Act, a person has beneficial ownership of a security as to which that person, directly or indirectly, through any contract, arrangement, understanding, relationship, or otherwise has or shares voting power and/or investment power of such security and as to which that person has the right to acquire beneficial ownership of such security within 60 days. In addition to Class A shares, this column includes Class B shares beneficially owned by such persons that are, together with a corresponding number of Tallgrass Equity Units, exchangeable at any time and from time to time for Class A shares on a one-for-one basis (subject to the terms of the Tallgrass Equity limited liability company agreement and our partnership agreement). See *"Certain Relationships and Related Party Transactions, and Director Independence-Exchange Right."*

(2) The Class A shares to be issued upon the exchange of Class B shares and Tallgrass Equity Units as described in footnote (1) above are deemed to be outstanding and beneficially owned by the person holding the Class B shares for the purpose of computing the percentage of beneficial ownership of Class A shares for that person and any group of which that person is a member, but are not deemed outstanding for purpose of computing the percentage of beneficial ownership of any other person. As such, the percentage of Class A shares shown as being beneficially owned by each person is based on an assumption that each such person exchanged all of such person's Class B shares, together with a corresponding number of Tallgrass Equity Units, for Class A shares and that no other person made a similar exchange.

(3) Represents the percentage of voting power of the Class A shares and Class B shares held by such person voting together as a single class.

(4) Consists of Class B shares held of record by: (i) KIA VIII (Rubicon), L.P., a Delaware limited partnership, or KIA VIII, and (ii) KEP VI AIV (Rubicon), LLC, a Delaware limited liability company, or KEP VI AIV. KIA VIII and KEP VI AIV, due to their common control, could be deemed to beneficially own each of the other's shares. Each of KIA VIII and KEP VI AIV disclaim such beneficial ownership. Frank T. Nickell, Thomas R. Wall, IV, George E. Matelich, Michael B. Goldberg, David I. Wahrhaftig, Frank K. Bynum, Jr., Philip E. Berney, Frank J. Loverro, James J. Connors, II, Church M. Moore, Stanley de J. Osborne, Christopher L. Collins, A. Lynn Alexander, Howard A. Matlin, John K. Kim, Henry

Mannix, III, Matthew S. Edgerton and Stephen C. Dutton (the "Kelso Individuals") may be deemed to share beneficial ownership of shares held of record or beneficially owned by KIA VIII and KEP VI AIV, by virtue of their status as managing members of KEP VI AIV and of Kelso GP VIII, LLC, a Delaware limited liability company, the principal business of which is serving as the general partner of KIA VIII (Rubicon) GP, L.P., a Delaware limited partnership, the principal business of which is serving as the general partner of KIA VIII. Each of Kelso GP VIII, LLC and KIA VIII (Rubicon) GP, L.P. due to their common control, could be deemed to beneficially own each other's securities and the shares held of record or beneficially owned by KIA VIII and KEP VI AIV. Kelso GP VIII, LLC disclaims beneficial ownership of all the securities owned of record, or deemed beneficially owned, by KIA VIII (Rubicon) GP, L.P., KIA VIII and KEP VI AIV, except to the extent, if any, of its pecuniary interest therein, and the inclusion of these securities in the table above shall not be deemed an admission of beneficial ownership of all the reported securities for any purpose. KIA VIII (Rubicon) GP, L.P. disclaims beneficial ownership of all of the securities owned of record, or deemed beneficially owned, by Kelso GP VIII, LLC, KIA VIII and KEP VI AIV, except to the extent, if any, of its pecuniary interest therein, and the inclusion of these securities in the table above shall not be deemed an admission of beneficial ownership of all the reported securities for any purpose. The Kelso Individuals may be deemed to share beneficial ownership of securities owned of record or beneficially owned by Kelso GP VIII, LLC, KIA VIII (Rubicon) GP, L.P., KIA VIII and KEP VI AIV, by virtue of their status as managing members of Kelso GP VIII, LLC and KEP VI AIV, but disclaim beneficial ownership of such securities, and the inclusion of these securities in the table above shall not be deemed an admission that any of the Kelso Individuals is the beneficial owner of these securities for any purposes. Frank J. Loverro, who serves as a Managing Director and Co-Chief Executive Officer of Kelso & Company, which manages the investments in KIA VIII, KEP VI AIV, is one of our directors. Stanley de J. Osborne, who serves as a Managing Director of Kelso & Company, is also one of our directors. The business address for these persons is c/o Kelso & Company, 320 Park Avenue, 24th Floor, New York, NY 10022.

(5) Consists of Class B shares held of record by Tallgrass Holdings, LLC. The manager of Tallgrass Holdings, LLC is EMG Fund II Management, LP. EMG Fund II Management, LP's general partner is EMG Fund II Management, LLC. John T. Raymond, who serves as one of our directors, is the sole member of EMG Fund II Management, LLC and as such, has sole voting and dispositive power with respect to the shares held by Tallgrass Holdings, LLC; however, he disclaims beneficial ownership of those shares except to the extent of his pecuniary interest therein. The address for Tallgrass Holdings, LLC is The Energy & Minerals Group, 2229 San Felipe, Suite 1300, Houston, Texas 77019.

(6) Consists of Class B shares held of record by Tallgrass KC. David G. Dehaemers, Jr. has sole voting and dispositive power with respect to the Class B shares held by Tallgrass KC; however, he disclaims beneficial ownership of those shares except to the extent of his pecuniary interest therein.

(7) As reported on Schedule 13G filed with the SEC on January 18, 2019. The business address for this person is Two World Financial Center, 225 Liberty Street, New York, New York 10281.

(8) As reported on Schedule 13G filed with the SEC on August 9, 2018. 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.

(9) As reported on Schedule 13G filed with the SEC on February 1, 2019. Kayne Anderson Capital Advisors, L.P. is the general partner (or general partner of the general partner) of the limited partnerships and investment adviser to the other accounts. Richard A. Kayne is the controlling shareholder of the corporate owner of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. Mr. Kayne is also a limited partner of each of the limited partnerships and a shareholder of the registered investment company. Kayne Anderson Capital Advisors, L.P. disclaims beneficial ownership of the shares reported, except those shares attributable to it by virtue of its general partner interests in the limited partnerships. Mr. Kayne disclaims beneficial ownership of the shares reported,

except those shares held by him or attributable to him by virtue of his limited partnership interests in the limited partnerships, his indirect interest in the interest of Kayne Anderson Capital Advisors, L.P. in the limited partnerships, and his ownership of common stock of the registered investment company. The business address for these persons is 1800 Avenue of the Stars, Second Floor, Los Angeles California 90067.

(10) As reported on Schedule 13G filed with the SEC on April 10, 2017. The business address for this person is 4265 San Felipe, 8th Floor, Houston, TX 77027.

(11) Consists of (i) 29,416,692 Class B shares held of record by Tallgrass KC, (ii) 281,171 Class B shares held indirectly through the David G. Dehaemers, Jr. Revocable Trust, dated April 26, 2006 (the "Dehaemers Trust"), for which Mr. Dehaemers serves as Trustee and (iii) 1,806,319 Class A shares held indirectly through the Dehaemers Trust. Mr. Dehaemers has sole voting and dispositive power with respect to the shares held by Tallgrass KC; however, he disclaims beneficial ownership of those shares except to the extent of his pecuniary interest therein.

(12) Consists of (i) 1,403,765 Class B shares held of record by Tallgrass KC and (ii) 1,499,288 Class A shares held indirectly through the William R. Moler Revocable Trust U.T.A. dated August 27, 2013 ("Moler Trust"), for which Mr. Moler serves as Trustee. Mr. Moler indirectly holds a membership interest in Tallgrass KC through the Moler Trust, that includes 1,403,765 TEGP Tracking Units. Pursuant to Tallgrass KC's limited liability company agreement, Mr. Moler is permitted to exchange his TEGP Tracking Units in Tallgrass KC for an equivalent number of Class A shares of TGE.

(13) Consists of (i) 2,183,636 Class B shares held of record by Tallgrass KC and (ii) 145,176 Class A shares held indirectly through the Brauchle Revocable Trust, under a trust agreement dated April 10, 2014, for which Mr. Brauchle serves as a Trustee (the "Brauchle Trust"). Mr. Brauchle indirectly holds a membership interest in Tallgrass KC through the Brauchle Trust, that includes 2,183,636 TEGP Tracking Units. Pursuant to Tallgrass KC's limited liability company agreement, Mr. Brauchle is permitted to exchange his TEGP Tracking Units in Tallgrass KC for an equivalent number of Class A shares of TGE.

(14) Consists of (i) 311,948 Class B shares held of record by Tallgrass KC and (ii) 47,030 Class A shares held directly by Mr. Jones. Mr. Jones holds a membership interest in Tallgrass KC that includes 311,948 TEGP Tracking Units. Pursuant to Tallgrass KC's limited liability company agreement, Mr. Jones is permitted to exchange his TEGP Tracking Units in Tallgrass KC for an equivalent number of Class A shares of TGE.

(15) Consists of (i) 46,386,232 Class B shares held of record by Tallgrass Holdings, LLC and (ii) 447,051 Class A shares held directly by John T. Raymond. The manager of Tallgrass Holdings, LLC is EMG Fund II Management, LP. EMG Fund II Management, LP's general partner is EMG Fund II Management, LLC. John T. Raymond, who serves as one of our directors, is the sole member of EMG Fund II Management, LLC and as such, has sole voting and dispositive power with respect to the shares held by Tallgrass Holdings, LLC; however, he disclaims beneficial ownership of those shares except to the extent of his indirect pecuniary interest therein.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information about our Class A shares that may be issued under equity compensation plans as of December 31, 2018:

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	3,049,644 [1]	$ 18.25	17,735,121
Equity compensation plans not approved by security holders [2]	—	$ —	—
Total	3,049,644	$ 18.25	17,735,121

(1) Amounts shown represent equity participation share awards outstanding under the Plans as of December 31, 2018. The outstanding awards will be settled in Class A shares 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 Class A shares may be issued except for the Plans.

For additional information regarding the Plans, see Note 16 – *Equity-Based Compensation* to our Consolidated Financial Statements in Item 8.—Financial Statements and Supplementary Data of this Annual Report.

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

We are a Delaware limited partnership formed in February 2015. Although we were formed as a limited partnership, we have elected to be taxed as a corporation for U.S. federal income tax purposes.

Limited Liability Company Agreement of Tallgrass Equity

As of February 8, 2019, we own Tallgrass Equity units representing 55.79% of the membership interests in Tallgrass Equity. In accordance with the Tallgrass Equity limited liability company agreement, the net profits and net losses of Tallgrass Equity will generally be allocated to the holders of Tallgrass Equity units on a pro rata basis in accordance with their relative number of Tallgrass Equity units held. Accordingly, net profits and losses of Tallgrass Equity are currently allocated 55.79% to us and 44.21% to the Exchange Right Holders with respect to their Tallgrass Equity units. If we cause a distribution to be made, such distribution will be made to the holders of Tallgrass Equity units on a pro rata basis in accordance with their relative number of Tallgrass Equity units held.

For purposes of any transfer or exchange of Tallgrass Equity units initially owned by the Exchange Right Holders and our Class B shares, the Tallgrass Equity limited liability company agreement and our partnership agreement contain provisions linking each such Tallgrass Equity unit with one of our Class B shares. Our Class B shares cannot be transferred without transferring an equal number of Tallgrass Equity units and vice versa.

The Exchange Right Holders and any permitted transferees of their Tallgrass Equity units each have the right to exchange all or a portion of their Tallgrass Equity units into Class A shares at an exchange ratio of one Class A share for each Tallgrass Equity unit exchanged. The above Exchange Right may be exercised only if, simultaneously therewith, an equal number of our Class B shares are transferred by the exercising party to us.

The above mechanisms are subject to customary conversion rate adjustments for equity splits, equity dividends and reclassifications.

In addition, pursuant to our partnership agreement and the Tallgrass Equity limited liability company agreement, our capital structure and the capital structure of Tallgrass Equity generally replicate one another and provide for customary antidilution mechanisms in order to maintain the one-for-one exchange ratio between the Tallgrass Equity units and Class B shares, on the one hand, and our Class A shares, on the other hand.

TGE Omnibus Agreement

In connection with the closing of the TGE IPO, we, our general partner, Tallgrass Equity and Tallgrass Energy Holdings entered into the TGE Omnibus Agreement, that addresses the following matters:

- Tallgrass Equity's obligation to reimburse Tallgrass Energy Holdings and its affiliates for expenses incurred (i) on our behalf, (ii) on behalf of our general partner and (iii) for any other purposes related to our business and activities or those of our general partner, including our public company expenses and general and administrative expenses; and
- Our use of the name "Tallgrass" and any associated or related marks.

Pursuant to the TGE Omnibus Agreement, Tallgrass Energy Holdings may perform, or cause its affiliates to perform, centralized general and administrative services for TGE, such as accounting, audit, business development, corporate record keeping, treasury services (including cash management), real property/land, legal, operations/engineering, investor relations, risk management, commercial/marketing, information technology, insurance, government relations/compliance, tax, payroll, human resources and environmental, health and safety. In exchange, Tallgrass Equity reimburses Tallgrass Energy Holdings and its affiliates for their expenses to the extent incurred on our behalf in providing these services. All reimbursements to our general partner, Tallgrass Energy Holdings and their respective affiliates by Tallgrass Equity will proportionally reduce cash distributions by Tallgrass Equity to its members, which in turn will reduce the amount of cash we distribute to our Class A shareholders.

Effective January 1, 2018, these costs are incurred by Tallgrass Equity directly. For the years ended December 31, 2017 and 2016, Tallgrass Equity reimbursed Tallgrass Management and its affiliates $2.0 million pursuant to the TGE Omnibus Agreement.

TEP Omnibus Agreement

In May 2013, TEP entered into an Omnibus Agreement with Tallgrass Equity (as successor to Tallgrass Development), Tallgrass Energy Holdings, and TEP GP, which we refer to as the TEP Omnibus Agreement, that governs TEP's relationship with them regarding the following matters:

- the provision by Tallgrass Energy Holdings to TEP of certain administrative services and TEP's agreement to reimburse it for such services;

- the provision by Tallgrass Energy Holdings of such employees as may be necessary to operate and manage TEP's business, and TEP's agreement to reimburse it for the expenses associated with such employees;
- certain indemnification obligations; and
- TEP's use of the name "Tallgrass" and related marks.

Pursuant to the TEP Omnibus Agreement, Tallgrass Energy Holdings may perform, or causes its affiliates to perform, centralized corporate, general and administrative services for TEP, 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, TEP reimburses Tallgrass Energy Holdings and its affiliates for their expenses to the extent incurred on TEP's behalf in providing these services.

Exchange Right

The Exchange Right Holders and any permitted transferees of their Tallgrass Equity units each have the right to exchange all or a portion of their Tallgrass Equity units into Class A shares at an exchange ratio of one Class A share for each Tallgrass Equity unit exchanged, which we refer to as the Exchange Right. The Exchange Right may be exercised only if, simultaneously therewith, an equal number of our Class B shares are transferred by the exercising party to us. Upon such exchange, we will cancel the Class B shares received from the exercising party.

For purposes of any transfer or exchange of Tallgrass Equity units initially owned by the Exchange Right Holders and our Class B shares, the Tallgrass Equity limited liability company agreement and our partnership agreement contain provisions effectively linking one Tallgrass Equity unit with one of our Class B shares. Class B shares cannot be transferred without transferring an equal number of Tallgrass Equity units and vice versa. In connection with the Secondary Offering completed in November 2016, the participating Exchange Right Holders exercised their Exchange Right with respect to a total of 10,350,000 Tallgrass Equity units and an equal number of Class B shares. In addition, during the year ended December 31, 2018, 2,821,332 Class A shares were issued and an equal number of Class B shares were cancelled as a result of the exercise of the Exchange Right.

The above mechanisms are subject to customary conversion rate adjustments for equity splits, equity dividends and reclassifications.

Registration Rights Agreement

In connection with the closing of the TGE IPO, we entered into a shareholder and registration rights agreement, which we refer to as the registration rights agreement, with certain of the Exchange Right Holders. Pursuant to the registration rights agreement, we agreed to register the resale of 109,504,440 Class A shares issuable upon exercise of the Exchange Right held by the Exchange Right Holders or any of their permitted transferees to the registration rights agreement under certain circumstances. In addition, we agreed to register the 27,554,785 Class A shares issuable upon the exercise of the Exchange Right with respect to 27,554,785 Tallgrass Equity units and Class B shares, respectively, issued in connection with the acquisition of the 25.01% membership interest in Rockies Express and the 5,619,218 additional TEP common units acquired by Tallgrass Equity in February 2018. We refer to such Class A shares issuable upon exercise of the Exchange Right as the Registrable Securities.

In accordance with our obligations under the registration rights agreement, we have registered the resale of 125,291,659 Class A shares issuable upon exercise of the Exchange Right pursuant to our Form S-3 (File No. 333-225382) filed with the SEC on June 1, 2018, which became effective June 13, 2018. We are required to maintain the effectiveness of such registration statement until the date on which all Registrable Securities covered by the shelf registration statement have been sold thereunder in accordance with the plan and method of distribution disclosed in the annual report included in the shelf registration statement, or otherwise cease to be Registrable Securities under the registration rights agreement.

Demand and Piggyback Rights

The Exchange Right Holders have the right to require that we register their Registrable Securities and/or facilitate an underwritten offering of their Registrable Securities. There is no aggregate limit on the number of such demand requests; however, the demand rights of these holders are subject to a number of size, frequency and other limitations. In November 2016, EMG and Kelso exercised this "demand" registration right under the registration rights agreement and together with the other participating Exchange Right Holders, sold 10,350,000 Class A Shares in the Secondary Offering that closed on November 22, 2016. For a period of 120 days following the closing of the Secondary Offering, the participating Exchange Right Holders were not permitted to exchange any of their Tallgrass Equity units pursuant to the terms of the underwriting agreement.

In the event we propose to conduct an underwritten offering of Registrable Securities, then the holders of Registrable Securities will generally have customary rights to participate in such offering, subject to customary offering size limitations and related allocation provisions and other limitations. Similarly, in the event that eligible holders demand that we conduct an underwritten offering of their Registrable Securities, then we will generally have customary rights to participate in such offering, subject to customary offering size limitations and related allocation provisions and other limitations.

Delay Rights

We will not be required to comply with any demand request, and may suspend the holders' ability to use any shelf registration statement, following our delivery of written notice to the holders of customary blackout periods and deferral events.

Expenses

The holders of Registrable Securities will pay certain selling expenses, including any underwriters' discounts and commissions. We will generally cause Tallgrass Equity to pay all other registration expenses in connection with our obligations under the registration rights agreement.

Pursuant to the terms of the registration rights agreement discussed above, the Company was obligated to cause Tallgrass Equity to pay all fees and expenses related to the Secondary Offering, excluding certain selling expenses, including any underwriters' discounts and commissions. The Company did not receive any proceeds from the sale of Class A shares in the Secondary Offering. The total expenses paid by Tallgrass Equity in connection with the Secondary Offering, and associated filings, were approximately $1.0 million.

Other Transactions

In January 2018, we 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 $30.6 million. The transaction closed on April 1, 2018. Kelso owns an indirect equity interest in Zenith Energy Terminals Holdings, LLC.

Effective February 1, 2018, TEP 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 its aggregate membership interest in Pony Express to 100%.

On February 7, 2018, Tallgrass Development merged into Tallgrass Development Holdings, a wholly-owned subsidiary of Tallgrass Equity, and as a result of the merger, Tallgrass Equity acquired a 25.01% membership interest in Rockies Express and an additional 5,619,218 TEP common units. As consideration for the acquisition, TGE and Tallgrass Equity issued 27,554,785 TGE Class B shares and Tallgrass Equity units, valued at approximately $644.8 million based on the closing price on February 6, 2018, to the limited partners of Tallgrass Development.

In August 2018, we entered into an agreement with Silver Creek to expand the Iron Horse joint venture through the contribution by us and Silver Creek of cash and additional Powder River Basin assets. These additional contributions closed in January 2019. The expanded joint venture operates under the name Powder River Gateway, LLC, and owns the Iron Horse Pipeline, the PRE Pipeline, a 70-mile crude oil pipeline that transports crude oil from the Powder River Basin to Guernsey, Wyoming, and crude oil terminal facilities in Guernsey, Wyoming. Effective January 1, 2019, we own a 51% membership interest in Powder River Gateway and continue to operate the joint venture, while Silver Creek owns a 49% membership interest. EMG owns an indirect equity interest in Silver Creek.

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 Tallgrass Equity (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) of 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,	
	2018	2017
	(in thousands)	
Audit fees [(1)]	$ 1,935	$ 1,843
Audit related fees [(2)]	—	—
Tax fees [(3)]	520	611
Total	$ 2,455	$ 2,454

(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, 2018.

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, 2018, 2017 and 2016

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, 2018 and 2017, and the related statements of income, members' equity, and cash flows for each of the three years in the period ended December 31, 2018.

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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matters

As described in Note 6 to the financial statements, the Company has significant transactions with related parties.

As discussed in Notes 2 and 7 to the financial statements, the Company changed the manner in which it accounts for revenue in 2018.

Our opinion is not modified with respect to these matters.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 8, 2019

ROCKIES EXPRESS PIPELINE LLC
BALANCE SHEETS

	December 31, 2018	December 31, 2017
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1.1	$ 25.7
Accounts receivable, net	76.8	75.8
Gas imbalances	7.4	6.3
Current portion of contract asset	31.8	—
Other current assets	3.6	14.6
Total Current Assets	120.7	122.4
Property, plant and equipment, net	5,759.0	5,939.2
Contract asset	157.0	—
Deferred charges and other assets	15.2	11.8
Total Noncurrent Assets	5,931.2	5,951.0
Total Assets	$ 6,051.9	$ 6,073.4
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts payable	$ 21.0	$ 20.3
Accrued interest	39.0	56.3
Accrued taxes	81.8	60.0
Current portion of long-term debt	525.0	550.0
Accrued other current liabilities	23.6	27.4
Total Current Liabilities	690.4	714.0
Long-term Liabilities and Deferred Credits:		
Long-term debt, net	1,492.7	2,014.8
Other long-term liabilities and deferred credits	10.2	34.5
Total Long-term Liabilities and Deferred Credits	1,502.9	2,049.3
Commitments and Contingencies		
Members' Equity:		
Members' equity	3,858.6	3,310.1
Total Liabilities and Members' Equity	$ 6,051.9	$ 6,073.4

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

ROCKIES EXPRESS PIPELINE LLC
STATEMENTS OF INCOME

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Revenues:			
Transportation services	$ 907.7	$ 839.6	$ 715.1
Natural gas sales	6.9	9.6	—
Total Revenues	914.6	849.2	715.1
Operating Costs and Expenses:			
Cost of transportation services	32.3	29.8	26.5
Cost of natural gas sales	5.0	7.3	—
Operations and maintenance	27.0	25.3	24.8
Depreciation and amortization	219.6	218.4	204.3
General and administrative	28.2	30.5	39.9
Taxes, other than income taxes	85.3	65.3	71.9
Total Operating Costs and Expenses	397.4	376.6	367.4
Operating Income	517.2	472.6	347.7
Other (Expense) Income:			
Interest expense, net	(150.0)	(168.0)	(158.6)
Gain on litigation settlement	—	150.0	61.7
Other income, net	2.3	3.4	27.7
Total Other Expense, net	(147.7)	(14.6)	(69.2)
Net Income to Members	$ 369.5	$ 458.0	$ 278.5

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, 2016	$ 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
Cumulative effect of ASC 606 implementation	125.2	51.0	42.9	—	31.3
Net Income to Members	369.5	44.9	232.2	—	92.4
Contributions from Members	576.5	1.6	430.7	—	144.2
Distributions to Members	(522.7)	(63.7)	(328.4)	—	(130.6)
Transfer of equity interest (see Note 1)	—	(861.7)	861.7	—	—
Balance at December 31, 2018	$ 3,858.6	$ —	$ 2,893.8	$ —	$ 964.8

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

ROCKIES EXPRESS PIPELINE LLC
STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Cash Flows from Operating Activities:			
Net income to Members	$ 369.5	$ 458.0	$ 278.5
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	224.7	223.7	209.6
Change in contract asset	(62.3)	—	—
Changes in components of working capital:			
Accounts receivable	(1.7)	(25.4)	28.2
Current regulatory assets and liabilities, net	10.0	3.4	(12.5)
Accounts payable and accrued other current liabilities	(19.6)	(7.0)	12.2
Accrued taxes	11.4	(7.6)	(0.6)
Other current assets and liabilities	(2.8)	—	(0.7)
Return of customer deposits	(29.9)	(55.7)	—
Receipt of customer deposits	8.4	5.8	52.9
Other operating, net	3.9	1.1	(22.5)
Net Cash Provided by Operating Activities	511.6	596.3	545.1
Cash Flows from Investing Activities:			
Capital expenditures	(36.5)	(108.9)	(305.7)
Other investing, net	(3.3)	(2.2)	(2.3)
Net Cash Used in Investing Activities	(39.8)	(111.1)	(308.0)
Cash Flows from Financing Activities:			
Contributions from Members	576.5	92.0	304.9
Distributions to Members	(522.7)	(669.9)	(471.6)
Repayment of senior notes	(550.0)	—	—
Other financing, net	(0.2)	—	—
Net Cash Used in Financing Activities	(496.4)	(577.9)	(166.7)
Net Change in Cash and Cash Equivalents	(24.6)	(92.7)	70.4
Cash and Cash Equivalents, beginning of period	25.7	118.4	48.0
Cash and Cash Equivalents, end of period	$ 1.1	$ 25.7	$ 118.4
Supplemental Disclosures:			
Cash payments for interest, net	$ (164.9)	$ (164.9)	$ (155.6)
Schedule of Noncash Investing and Financing Activities:			
Increase in accrual for payment of property, plant and equipment	$ 2.8	$ —	$ —

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, 2018 are as follows:

- 75% - TEP REX Holdings, LLC ("TEP REX"), an indirect wholly owned subsidiary of Tallgrass Energy Partners, LP ("TEP"); and
- 25% - P66REX LLC, a wholly owned subsidiary of Phillips 66.

On March 31, 2017, TEP, Tallgrass Development LP ("TD"), and Rockies Express Holdings, LLC ("REX Holdings"), an indirect wholly owned subsidiary of TD, 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 REX's aggregate membership interest in Rockies Express to 49.99%.

On February 7, 2018, Tallgrass Development Holdings, LLC ("Tallgrass Development Holdings"), a wholly owned subsidiary of Tallgrass Equity, 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 Equity is the sole member of TEP's general partner. Effective July 1, 2018, REX Holdings was merged into TEP REX, resulting in TEP REX owning a 75% membership interest in Rockies Express.

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 periodically reviews and evaluates 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 $1.0 million and $2.0 million at December 31, 2018 and 2017, respectively.

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 $0.7 million and $10.9 million at December 31, 2018 and 2017, respectively, and regulatory liabilities of approximately $1.8 million and $2.0 million at December 31, 2018 and 2017, respectively. Regulatory assets and liabilities at December 31, 2018 and 2017 were primarily attributable to the fuel tracker discussed in *"Fuel Recovery Mechanism"* above. For additional details see Note 10 – *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

Rockies Express has elected to compute depreciation using a composite method employed by applying a single depreciation rate to a group of assets with similar economic characteristics. The annual composite rate of depreciation for the years ended December 31, 2018, 2017, and 2016 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, 2018, 2017 and 2016 Rockies Express recognized AFUDC associated with the estimated cost of debt of approximately $0.3 million, $0.2 million, and $9.3 million, respectively, recorded as "Interest expense, net" on the accompanying statements of income. During the years ended December 31, 2018, 2017, and 2016, Rockies Express recognized AFUDC associated with the estimated cost of capital from equity funds of approximately $0.6 million, $0.5 million, and $24.8 million, respectively, recorded as "Other income, net" on the accompanying statements of income.

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.

Management 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. Revenues presented in the comparative financial statements for periods prior to January 1, 2018 have not been 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 rates that vary throughout the term of the contract. 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.

See Note 7 – *Revenue from Contracts with Customers* for revenue disclosures related to both the implementation and 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.

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 $0.5 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, 2018, 2017, and 2016 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, 2018 and 2017.

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.

Accounting Pronouncements Not Yet Adopted

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 right-of-use ("ROU") 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.

Subsequent to issuing ASU 2016-02, the FASB has issued a series of subsequent updates to the lease guidance in Topic 842, including ASU No. 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842, ASU No. 2018-10, Codification Improvements to Topic 842, Leases, ASU No. 2018-11, Leases (Topic 842): Targeted Improvements, and ASU 2018-20, Leases (Topic 842): Narrow-Scope Improvements for Lessors. The amendments in ASU 2016-02, ASU 2018-01, ASU 2018-10, ASU 2018-11, and ASU 2018-20 are effective for public entities for annual reporting periods beginning after December 15, 2018, 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, 2019. The approach allows Rockies Express to (i) initially apply ASC 842 at the adoption date, January 1, 2019 and (ii) continue reporting comparative periods presented in the financial statements in the period of adoption under ASC 840. Rockies Express will not recast comparative periods in the accompanying financial statements. Management elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allowed Rockies Express to carry forward the historical lease classification. Management also elected the practical expedient related to land easements, allowing Rockies Express to carry forward the accounting treatment for land easements on existing agreements.

Adoption of the new standard resulted in the recognition of ROU assets and lease liabilities for operating leases of approximately $40.0 million.

3. Property, Plant and Equipment

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

	December 31,	
	2018	2017
	(in millions)	
Natural gas pipelines	$ 7,677.0	$ 7,661.2
General and other	15.8	15.4
Construction work in progress	27.8	11.9
Accumulated depreciation and amortization	(1,961.6)	(1,749.3)
Total property, plant and equipment, net	$ 5,759.0	$ 5,939.2

Depreciation expense was approximately $219.6 million, $218.4 million and $204.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

4. Financing

Debt

Total outstanding debt as of December 31, 2018 and 2017 consisted of the following:

	December 31,	
	2018	2017
	(in millions)	
6.85% senior notes due July 15, 2018 [(1)]	$ —	$ 550.0
6.00% senior notes due January 15, 2019 [(2)]	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	(7.3)	(10.2)
Total debt, net	2,017.7	2,564.8
Less: Current portion	(525.0)	(550.0)
Total long-term debt, net	$ 1,492.7	$ 2,014.8

(1) The 6.85% senior notes were repaid on July 15, 2018. The repayment was funded by contributions from the Rockies Express Members, as discussed further below.

(2) The 6.00% senior notes were repaid on January 15, 2019. The repayment was funded by the issuance of a 364-Day Term Loan Agreement effective January 8, 2019, as discussed further below.

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, 2018, 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, 2018 are summarized as follows (in millions):

Year	Scheduled Maturities
2019	$ 525.0
2020	750.0
2021	—
2022	—
2023	—
Thereafter	750.0
Total scheduled maturities	2,025.0
Unamortized debt discount and deferred financing costs	(7.3)
Total debt	$ 2,017.7

The 6.00% senior notes were repaid on January 15, 2019. The repayment was funded by the issuance of a 364-Day Term Loan Agreement effective January 8, 2019 (the "Term Loan") which matures on January 7, 2020. As a result, Rockies Express has $525 million of debt scheduled to mature within one year of the issuance of these financial statements. 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 8, 2019 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, 2018, 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. 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.

Covenants Under the Term Loan and Revolving Credit Facility

The Term Loan and the revolving credit facility generally require Rockies Express to comply with various affirmative and negative covenants, including a limit on the leverage ratio (as defined in each 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, 2018, Rockies Express was in compliance with the covenants required under the revolving credit facility.

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, 2018 and 2017, 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, 2018	$ —	$ 2,086.9	$ —	$ 2,086.9	$ 2,017.7
December 31, 2017	$ —	$ 2,752.1	$ —	$ 2,752.1	$ 2,564.8

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, 2018.

5. Members' Equity

During the years ended December 31, 2018, 2017, and 2016, Rockies Express made distributions to Members of $522.7 million, $669.9 million, and $471.6 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 11 – *Legal and Environmental Matters.*

During the years ended December 31, 2018, 2017, and 2016, Rockies Express received contributions from Members of $576.5 million, $92.0 million, and $304.9 million, respectively. Contributions from Members during the year ended December 31, 2018 included a special contribution of approximately $550 million to fund the repayment of senior notes as discussed in Note 4 – *Financing*. 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 10 – *Regulatory Matters*.

Additional contributions and distributions were made subsequent to December 31, 2018. For details see Note 12 – *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,		
	2018	2017	2016
		(in millions)	
Revenues: Transportation services [1]	$ —	$ —	$ 14.4
Charges to Rockies Express:			
Compensation, benefits and other charges	$ 18.1	$ 18.6	$ 20.6
General and administrative charges from affiliate	$ 10.3	$ 8.9	$ 9.4
Management Fees:			
Tallgrass NatGas Operator, LLC	$ 7.5	$ 8.5	$ 6.2

(1) Transportation services revenue for the year ended December 31, 2016 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,	
	2018	2017
	(in millions)	
Payables to affiliated companies:		
TEP	$ 3.4	$ 1.3
TD	—	2.3
Total payables to affiliated companies	$ 3.4	$ 3.6

Gas imbalances with affiliated shippers are as follows:

	December 31,	
	2018	2017
	(in millions)	
Affiliate gas imbalance receivables	$ 0.8	$ 0.4

7. Revenue from Contracts with Customers

As discussed in Note 2 – *Summary of Significant Accounting Policies*, Rockies Express adopted the guidance in ASC Topic 606 effective January 1, 2018 using the modified retrospective method of adoption. As a result, revenue reported for the years ended December 31, 2017 and 2016 have not been revised. The following tables provide the impact of the guidance on the Rockies Express balance sheet as of December 31, 2018 and statement of income for the year ended December 31, 2018:

	December 31, 2018		
	As currently reported	Under previous guidance	Impact of ASC Topic 606
		(in millions)	
Current portion of contract asset	$ 31.8	$ —	$ 31.8 [1]
Contract asset	$ 157.0	$ —	$ 157.0 [1]

	Year Ended December 31, 2018		
	As currently reported	Under previous guidance	Impact of ASC Topic 606
		(in millions)	
Transportation services	$ 907.7	$ 845.4	$ 62.3 (1)
General and administrative	$ 28.2	$ 27.6	$ 0.6 (2)
Net Income to Members	$ 369.5	$ 307.8	$ 61.7

(1) Reflects the impact of the allocation of the transaction price to a series of individual performance obligations in certain long-term transportation contracts with rates that vary throughout the term of the contract and related contract asset.

(2) Reflects the additional management fee associated with the effect of the change in gas transportation revenue.

Disaggregated Revenue

A summary of our revenue by line of business is as follows:

	Year Ended December 31, 2018
	(in millions)
Firm Transportation - West to East	$ 467.7
Firm Transportation - East to West	425.0
All other	15.0
Total firm transportation	907.7
Natural gas sales	6.9
Total revenue	$ 914.6

Performance Obligations

A performance obligation is a promise in a contract to transfer a distinct good or service to the customer, and is the unit of account in ASC Topic 606. A contract's transaction price is allocated to each distinct performance obligation and recognized as revenue when, or as, the performance obligation is satisfied. The majority of Rockies Express' contracts have a single performance obligation and are billed and collected monthly. These performance obligations typically include an obligation to stand ready to provide natural gas transportation service over the life of the contract, which is a series. These performance obligations are satisfied over time using each day of service to measure progress toward satisfaction of the performance obligation.

Rockies Express also engages in commodity sales, in which the performance obligations include an obligation to deliver the specified volume of a commodity to the designated receipt point. Revenue from commodity sales is recognized at a point in time when the customer obtains control of the commodity, typically upon delivery to the designated delivery point when the customer accepts and takes possession of the commodity.

On December 31, 2018, we had $7.5 billion of remaining performance obligations, which we refer to as total backlog. Total backlog includes performance obligations under firm transportation contracts, and excludes variable consideration that is not estimated at contract inception, as discussed further below. We expect to recognize the total backlog during future periods as follows (in millions):

Year	**Estimated Revenue**
2019	$ 853.9
2020	617.3
2021	606.3
2022	576.2
2023	572.0
Thereafter	4,278.5
Total	$ 7,504.2

Contract Estimates

Accounting for long-term contracts involves the use of various techniques to estimate total contract revenue. Contract estimates are based on various assumptions to project the outcome of future events that often span several years.

The nature of our contracts gives rise to several types of variable consideration, including volumetric charges for actual volumes delivered, overrun charges, and other fees that are contingent on the actual volumes delivered by our customers. As the amount of variable consideration is allocable to each distinct performance obligation within the series of performance obligations that comprise the performance obligation, we do not estimate the total variable consideration for the overall performance obligation because the uncertainty related to the consideration is resolved each month as the distinct service is provided. Consequently, we are able to include in the transaction price each month the actual amount of variable consideration because no uncertainty exists surrounding the services provided that month.

Contract Balances

The timing of revenue recognition, billings, and cash collections may result in billed accounts receivable, unbilled receivables (contract assets), and deferred revenue (contract liabilities) on our balance sheets. Revenue is generally billed and collected monthly based on services provided or volumes sold. As of December 31, 2018, we had recognized a contract asset of $188.8 million reflecting the amount by which the revenue recognized exceeds the actual cash collected from certain contracts with rates that vary throughout the term of the contract.

8. Commitments and Contingent Liabilities

Leases

Total rental expense under operating leases was $29.2 million for the years ended December 31, 2018, 2017, and 2016. Future minimum commitments related to these leases as of December 31, 2018 are as follows (in millions):

Year		Future Minimum Lease Payments
2019	$	29.1
2020		29.1
2021		29.1
2022		29.1
2023		29.1
Thereafter		116.4
Total	$	261.9

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 $60.8 million of Rockies Express' capital expenditure budget for 2019 had been committed for purchases of property, plant and equipment at December 31, 2018.

9. Major Customers

During 2018, three non-affiliated shippers accounted for $168.5 million (18%), $118.7 million (13%), and $112.2 million (12%), respectively of Rockies Express' total revenues. 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. Rockies Express attempts to mitigate credit risk by seeking collateral or financial guarantees and letters of credit from customers.

10. 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.

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 Natural Gas Act ("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. On April 4, 2018, the FERC issued a letter order accepting Rockies Express' proposal, subject to certain modifications. Rockies Express submitted a compliance filing reflecting the approved tariff provisions and requested modifications on April 10, 2018. No comments on the compliance filing were submitted by the comment deadline of April 16, 2018. On April 18, 2018, the FERC issued an order accepting Rockies Express' compliance filing effective April 19, 2018.

2018 Annual FERC Fuel Tracking Filing - FERC Docket No. RP18-453

On February 20, 2018, in Docket No. RP18-453, Rockies Express made its annual fuel and power cost tracker filing with a proposed effective date of April 1, 2018. The FERC issued an order accepting the filing on March 19, 2018.

Cheyenne Hub Enhancement Project - FERC Docket CP18-103

On March 2, 2018, Rockies Express submitted an application pursuant to section 7(c) of the NGA for a certificate of public convenience and necessity authorizing the construction and operation of certain booster compressor units and ancillary facilities located at the Cheyenne Hub in Weld County, Colorado that will enable Rockies Express to provide a new hub service allowing for firm receipts and deliveries between Rockies Express and certain other interconnected pipelines at the Cheyenne Hub. The comment period for the Cheyenne Hub Enhancement Project closed on April 9, 2018. To date, various comments have been filed by market participants and others regarding the proposed project. Rockies Express has also responded to data requests from FERC's relevant program offices. On October 11, 2018, the FERC issued a Notice of Schedule of Environmental Review setting December 18, 2018 as the date of issuance of the Environmental Assessment and March 18, 2019 as the deadline for decisions by other federal agencies on requests for authorizations for the proposed project. On December 18, 2018, the FERC issued the Environmental Assessment.

Rockies Express Form No. 501-G Filing - FERC Docket No. RP19-412

On December 6, 2018, Rockies Express submitted its one-time informational filing in compliance with Order No. 849, which required interstate natural gas pipelines to make a one-time informational filing on the rate effect of the changes in tax laws and policy following the Tax Cuts and Jobs Act and FERC's changes to its Income Tax Policy Statement following the decision of the U.S. Court of Appeals for the D.C. Circuit in United Airlines, Inc. v. FERC in 2016. The filing remains pending before the FERC.

11. 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, 2018 or 2017.

Ohio Public Utility Excise Tax

The Ohio Tax Commissioner has assessed Rockies Express a public utility excise tax on transactions concerning product that entered and exited Rockies Express within the state of Ohio. This tax applies to gross receipts from all business conducted within the state, but exempts all receipts derived wholly from interstate business. Rockies Express has disputed any obligation to pay Ohio's public utility excise tax, but has paid the taxes as assessed in order to preserve its right to appeal. The dispute is currently pending before the Ohio Supreme Court, with a final decision possible by the end of 2019. It is Rockies Express' position that the relevant statute exempts receipts derived wholly from interstate business from the public utility excise tax. The Ohio Supreme Court and the United States Supreme Court have both held that, once it enters an interstate pipeline, natural gas is moving in "interstate commerce" for the duration of its journey until it is delivered to a local distribution system. As of December 31, 2018, Rockies Express has paid public utility excise taxes to the state of Ohio totaling $7.1 million and has accrued an additional $3.3 million for amounts expected to be assessed through the year ended December 31, 2018. While it is difficult to accurately predict how the Ohio Supreme Court will decide the case, Rockies Express is optimistic about the ultimate outcome and has recorded a $10.4 million asset representing the anticipated refund of the public utility excise taxes paid.

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.

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. The release required Rockies Express to shut off the flow through the segment until February 27, 2018, when temporary repairs were completed allowing the segment to be placed back into service. Total cost of remediation was approximately $6.1 million prior to any insurance recoveries. Permanent repairs were completed in September 2018. As of February 8, 2019, Rockies Express has recovered a significant majority of these costs from insurance.

12. Subsequent Events

Subsequent events, which are events or transactions that occurred after December 31, 2018 through the issuance of the accompanying financial statements, have been evaluated through February 8, 2019.

Members' Equity

Rockies Express paid distributions of $46.3 million to its Members and received contributions from its Members of $7.9 million in January 2019.

(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
2.1	Agreement and Plan of Merger, dated as of March 26, 2018, by and among Tallgrass Energy GP, LP, Tallgrass Equity, LLC, Razor Merger Sub, LLC, Tallgrass Energy Partners, LP and Tallgrass MLP GP, LLC (incorporated by reference to Exhibit 2.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on March 27, 2018).
2.2	Agreement and Plan of Merger, dated as of February 7, 2018, by and among Tallgrass Energy GP, LP, Tallgrass Development, LP, Tallgrass Equity, LLC, Tallgrass Development Holdings, LLC and Tallgrass Energy Holdings, LLC (incorporated by reference to Exhibit 2.2 to Tallgrass Energy, LP's Quarterly Report on Form 10-Q filed on May 3, 2018).
3.1	Certificate of Limited Partnership of Tallgrass Energy GP, LP, dated February 10, 2015 (incorporated by reference to Exhibit 3.1 to Tallgrass Energy GP, LP's Registration Statement on Form S-1 filed February 24, 2015).
3.2	Certificate of Formation of TEGP Management, LLC, dated February 10, 2015 (incorporated by reference to Exhibit 3.3 to Tallgrass Energy GP, LP's Registration Statement on Form S-1 filed February 24, 2015).
3.3	Certificate of Formation of Tallgrass GP Holdings, LLC, dated March 28, 2013 (now known as Tallgrass Equity, LLC) (incorporated by reference to Exhibit 3.5 to Tallgrass Energy GP, LP's Registration Statement on Form S-1 filed February 24, 2015).
3.4	Certificate of Amendment to Certificate of Formation of Tallgrass GP Holdings, LLC, dated February 20, 2015 (now known as Tallgrass Equity, LLC) (incorporated by reference to Exhibit 3.6 to Tallgrass Energy GP, LP's Registration Statement on Form S-1 filed February 24, 2015).
3.5	Second Amended and Restated Limited Liability Company Agreement of Tallgrass Equity, LLC, dated May 12, 2015 (incorporated by reference to Exhibit 3.7 to Tallgrass Energy GP, LP's Quarterly Report on Form 10-Q filed on June 18, 2015).
3.6	Certificate of Amendment to Limited Liability Company Certificate of Formation of TEGP Management, LLC, dated June 29, 2018 (incorporated by reference to Exhibit 3.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on July 2, 2018).
3.7	Certificate of Amendment to Certificate of Limited Partnership of Tallgrass Energy GP, LP, dated June 29, 2018 (incorporated by reference to Exhibit 3.2 to Tallgrass Energy, LP's Current Report on Form 8-K filed on July 2, 2018).
3.8	Second Amended and Restated Agreement of Limited Partnership of Tallgrass Energy, LP, dated July 1, 2018 (incorporated by reference to Exhibit 3.3 to Tallgrass Energy, LP's Current Report on Form 8-K filed on July 2, 2018).
3.9	Second Amended and Restated Limited Liability Company Agreement of Tallgrass Energy GP, LLC, dated July 1, 2018 (incorporated by reference to Exhibit 3.4 to Tallgrass Energy, LP's Current Report on Form 8-K filed on July 2, 2018).
4.1	Specimen certificate representing Class A Shares (incorporated by reference to Exhibit 4.1 to Tallgrass Energy GP, LP's Registration Statement on Form S-1/A filed April 20, 2015).
4.2	Registration Rights Agreement, dated May 12, 2015, by and among Tallgrass Energy GP, LP and each of the Initial Holders listed on an annex thereto (incorporated by reference to Exhibit 4.2 to Tallgrass Energy GP, LP's Quarterly Report on Form 10-Q filed on June 18, 2015).
4.3	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 Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on September 1, 2016).
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 Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on September 1, 2016).
4.5	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 Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on September 15, 2017).

4.6	Form of 5.50% Senior Note (included as Exhibit A in Exhibit 4.1 which is incorporated by reference to Exhibit 4.1 to Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on September 15, 2017).
4.7	Indenture, dated as of September 26, 2018, 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 Tallgrass Energy, LP's Current Report on Form 8-K filed on September 26, 2018).
4.8	Form of 4.75% Senior Note (included as Exhibit A in Exhibit 4.1 which is incorporated by reference to Exhibit 4.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on September 26, 2018).
10.1	Omnibus Agreement, dated May 12, 2015, by and among Tallgrass Energy Holdings, LLC, Tallgrass Energy GP, LP, TEGP Management, LLC and Tallgrass Equity, LLC (incorporated by reference to Exhibit 10.1 to Tallgrass Energy GP, LP's Current Report on Form 8-K filed May 12, 2015).
10.2†	Form of Employee Equity Participation Share Agreement (incorporated by reference to Exhibit 4.5 to the Partnership's Registration Statement on Form S-8 filed on July 17, 2015).
10.3†	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 Tallgrass Energy Partners, LP's Annual Report on Form 10-K filed February 15, 2017).
10.4†	Form of Employee Equity Participation Unit Agreement (incorporated by reference to Exhibit 4.5 to Tallgrass Energy Partners, LP's Registration Statement on Form S-8 filed on June 18, 2013).
10.5	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).
10.6	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).
10.7	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).
10.8	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).
10.9	Form of Employee Equity Participation Unit Agreement (incorporated by reference to Exhibit 10.1 to Tallgrass Energy Partners, LP's Current Report on Form 10-Q filed on November 2, 2017).
10.10	Support Agreement, dated as of March 26, 2018, by and among Tallgrass Energy GP, LP, Tallgrass Equity, LLC and Tallgrass Energy Partners, LP (incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on March 27, 2018).
10.11	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 Tallgrass Energy Partners, LP's Current Report on Form 8-K filed May 17, 2013).
10.12	Second Amended and Restated Credit Agreement, dated June 2, 2017, by and among Tallgrass Energy Partners, LP, Wells Fargo Bank, National Association, as administrative agent, and a syndicate of lenders named therein (incorporated by reference to Exhibit 10.1 to Tallgrass Energy Partners, LP’s Quarterly Report on Form 10-Q filed on August 2, 2017).
10.13	Tallgrass Energy GP, LLC Long-Term Incentive Plan (as amended and restated effective August 2, 2018) (incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP’s Quarterly Report on Form 10-Q filed on August 2, 2018).
10.14	Tallgrass MLP GP, LLC Long-Term Incentive Plan (as amended and restated effective August 2, 2018) (incorporated by reference to Exhibit 10.2 to Tallgrass Energy, LP’s Quarterly Report on Form 10-Q filed on August 2, 2018).

10.15	Form of Equity Participation Share Agreement (incorporated by reference to Exhibit 10.3 to Tallgrass Energy, LP's Quarterly Report on Form 10-Q filed on August 2, 2018).
10.16	Amendment No. 1 to Second Amended and Restated Credit Agreement, dated July 26, 2018, (incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on July 27, 2018).
21.1*	List of Subsidiaries of Tallgrass Energy, LP.
23.1*	Consent of PricewaterhouseCoopers LLP on Consolidated Financial Statements of Tallgrass Energy, LP and the effectiveness of Tallgrass Energy, 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, LP

By: Tallgrass Energy GP, LLC, its general partner

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

David G. Dehaemers, Jr.

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

Date: February 8, 2019

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 8, 2019
/s/ Gary J. Brauchle Gary J. Brauchle	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 8, 2019
/s/ Gary D. Watkins Gary D. Watkins	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 8, 2019
/s/ Frank J. Loverro Frank J. Loverro	Director	February 8, 2019
/s/ Stanley de J. Osborne Stanley de J. Osborne	Director	February 8, 2019
/s/ Jeffrey A. Ball Jeffrey A. Ball	Director	February 8, 2019
/s/ John T. Raymond John T. Raymond	Director	February 8, 2019
/s/ William R. Moler William R. Moler	Director	February 8, 2019
/s/ Thomas A. Gerke Thomas A. Gerke	Director	February 8, 2019
/s/ Roy N. Cook Roy N. Cook	Director	February 8, 2019
/s/ Terrance D. Towner Terrance D. Towner	Director	February 8, 2019

Exhibit 21.1

Tallgrass Energy, LP
Subsidiaries

Company	**Jurisdiction of Organization**
Alpha Reclaim Technology, LLC	Texas
BNN Colorado Water, Inc.	Colorado
BNN Colorado Water, LLC	Delaware
BNN Great Plains, LLC	Delaware
BNN North Dakota, LLC	Delaware
BNN Recycle, LLC	Delaware
BNN Redtail, LLC	Delaware
BNN South Texas, LLC	Delaware
BNN Water Solutions, LLC	Delaware
BNN West Texas, LLC	Delaware
BNN Western, LLC	Delaware
Cheyenne Connector Pipeline, Inc.	Colorado
Cheyenne Connector, LLC	Delaware
Deeprock Development, LLC	Delaware
Pawnee Terminal, LLC	Delaware
Plaquemines Liquids Terminal, LLC	Delaware
Seahorse Pipeline, LLC	Delaware
Stanchion Energy, LLC	Delaware
Tallgrass Cheyenne Connector Holdings, LLC	Delaware
Tallgrass Colorado Pipeline, Inc.	Colorado
Tallgrass Energy Finance Corp.	Delaware
Tallgrass Energy Investments, LLC	Delaware
Tallgrass Energy Partners, LP	Delaware
Tallgrass Equity Investments, LLC	Delaware
Tallgrass Equity, LLC	Delaware
Tallgrass Interstate Gas Transmission, LLC	Colorado
Tallgrass PRG Holdings, LLC	Delaware
Tallgrass PRG Operator, LLC	Delaware
Tallgrass Management, LLC	Delaware
Tallgrass Midstream Gathering, LLC	Colorado
Tallgrass Midstream, LLC	Delaware
Tallgrass MLP GP, LLC	Delaware
Tallgrass MLP Operations, LLC	Delaware
Tallgrass NatGas Operator, LLC	Delaware
Tallgrass PLT Operator, LLC	Delaware
Tallgrass Pony Express Pipeline, LLC	Delaware
Tallgrass Sterling Terminal, LLC	Delaware
Tallgrass Terminals, LLC	Delaware
TEP REX Holdings, LLC	Delaware
Trailblazer Pipeline Company 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 (No. 333-225382), S-3/ASR (No. 333-226086), S-8 (Nos. 333-226537 and 333-205717) of Tallgrass Energy, LP, of our report dated February 8, 2019, 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 8, 2019

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 (No. 333-225382), S-3/ASR (No. 333-226086), S-8 (Nos. 333-226537 and 333-205717) of Tallgrass Energy, LP, of our report dated February 8, 2019, relating to the financial statements of Rockies Express Pipeline LLC, which appears in this Form 10-K of Tallgrass Energy, LP.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 8, 2019

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, 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 Energy GP, LLC (the general partner of Tallgrass Energy, LP)

Date: February 8, 2019

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, 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 Energy GP, LLC (the general partner of Tallgrass Energy, LP)

Date: February 8, 2019

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, LP (the “Partnership”) on Form 10-K for the year ended December 31, 2018, 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 Energy 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 Energy GP, LLC (the general partner of Tallgrass Energy, LP)

Date: February 8, 2019

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, LP (the "Partnership") on Form 10-K for the year ended December 31, 2018, 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 Energy 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 and of Tallgrass Energy GP, LLC (the general partner of Tallgrass Energy, LP)

Date: February 8, 2019

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained and furnished to the Securities and Exchange Commission or its staff upon request.

CORPORATE INFORMATION

BOARD OF DIRECTORS

David G. Dehaemers Jr.

William R. Moler

Jeffrey A. Ball

Roy N. Cook

Thomas A. Gerke

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
Executive Vice President,
General Counsel & Secretary

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TRANSFER AGENT

American Stock Transfer and Trust

TICKER SYMBOL

NYSE: TGE

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TALLGRASS ENERGY

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