Tallgrass Energy Partners, LP
Form 10-Q
May 09, 2016

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

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended March 31, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number 001-35917

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

Delaware	46-1972941
(State or other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification Number)
4200 W. 115th Street, Suite 350	
Leawood, Kansas	66211
(Address of Principal Executive Offices)	(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer", and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x
On May 9, 2016, the Registrant had 72,097,211 Common Units and 834,391 General Partner Units outstanding.

TALLGRASS ENERGY PARTNERS, LP
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Glossary of Common Industry and Measurement Terms
Bakken oil production area: Montana and North Dakota in the United States and Saskatchewan and Manitoba in Canada.
Barrel (or bbl): forty two U.S. gallons.
Base Gas (or Cushion Gas): the volume of gas that is intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates.
BBtu: one billion British Thermal Units.
Bcf: one billion cubic feet.
British Thermal Units or Btus: the amount of heat energy needed to raise the temperature of one pound of water by one degree Fahrenheit.
Commodity sensitive contracts or arrangements: contracts or other arrangements, including tariff provisions, that directly expose our cash flows to increases and decreases in the price of commodities such as crude oil, natural gas and NGLs. Examples are Keep Whole Processing Contracts and Percent of Proceeds Processing Contracts, as well as pipeline loss allowances on our pipelines.
Condensate: a NGL with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
Contract barrels: barrels of crude oil that our customers have contractually agreed to ship in exchange for firm service assurance of capacity and deliverability to delivery points.
Delivery point: any point at which product in a pipeline is delivered to or for the account of a customer.
Dry gas: a gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.
Dth: a dekatherm, which is a unit of energy equal to 10 therms or one million British thermal units.
End-user markets: the ultimate users and consumers of transported energy products.
EPA: the United States Environmental Protection Agency.
FERC: Federal Energy Regulatory Commission.
Firm fee contracts: firm fee contracts generally obligate our customers to pay a fixed recurring charge to reserve an agreed upon amount of capacity and/or deliverability on our assets, regardless if the contracted capacity is actually used by the customer. Such contracts are also commonly known as "take-or-pay" contracts.
Firm services: services pursuant to which customers receive firm assurances regarding the availability of capacity and/or deliverability of natural gas, crude oil or other hydrocarbons or water on our assets up to a contracted amount.
Fractionation: the process by which NGLs are further separated into individual, typically more valuable components including ethane, propane, butane, isobutane and natural gasoline.
GAAP: generally accepted accounting principles in the United States of America.
GHGs: greenhouse gases.
Header system: networks of medium-to-large-diameter high pressure pipelines that connect local gathering systems to large diameter high pressure long-haul transportation pipelines.
Interruptible services: services pursuant to which customers receive limited, or no, assurances regarding the availability of capacity and deliverability in our assets.
Keep Whole Processing Contracts: natural gas processing contracts in which we are required to replace the Btu content of the NGLs extracted from inlet wet gas processed with purchased dry natural gas.
Line fill: the volume of oil, in barrels, in the pipeline from the origin to the destination.

Liquefied natural gas or LNG: natural gas that has been cooled to minus 161 degrees Celsius for transportation, typically by ship. The cooling process reduces the volume of natural gas by 600 times.
Local distribution company or LDC: LDCs are involved in the delivery of natural gas to consumers within a specific geographic area.
Long-term: with respect to any contract, a contract with an initial duration greater than one year.
MMBtu: one million British Thermal Units.
Mcf: one thousand cubic feet.
MMcf: one million cubic feet.
Natural gas liquids or NGLs: those hydrocarbons in natural gas that are separated from the natural gas as liquids through the process of absorption, condensation, adsorption or other methods in natural gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline and liquefied petroleum gases. Natural gas liquids include natural gas plant liquids (primarily ethane, propane, butane and isobutane) and lease condensate (primarily pentanes produced from natural gas at lease separators and field facilities).
Natural Gas Processing: the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream.
Non-contract barrels (or walk-up barrels): barrels of crude oil that our customers ship based solely on availability of capacity and deliverability with no assurance of future capacity.
No-notice service: those services pursuant to which customers receive the right to transport or store natural gas on assets outside of the daily nomination cycle without incurring penalties.
NYMEX: New York Mercantile Exchange.
Park and loan services: those services pursuant to which customers receive the right to store natural gas in (park), or borrow gas from (loan), our facilities on a seasonal basis.
Percent of Proceeds Processing Contracts: natural gas processing contracts in which we process our customer's natural gas, sell the resulting NGLs and residue gas and divide the proceeds of those sales between us and the customer. Some percent of proceeds contracts may also require our customers to pay a monthly reservation fee for processing capacity.
PHMSA: the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration.
Play: a proven geological formation that contains commercial amounts of hydrocarbons.
Produced water: all water removed from a well as a byproduct of the production of hydrocarbons and water removed from a well in connection with operations being conducted on the well, including naturally occurring water in the recovery formation, flow back water recovered during completion and fracturing operations and water entering the recovery formation through water flooding techniques.
Receipt point: the point where a product is received by or into a gathering system, processing facility, or transportation pipeline.
Reservoir: a porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (such as crude oil and/or natural gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.
Residue gas: the natural gas remaining after being processed or treated.
Shale gas: natural gas produced from organic (black) shale formations.
Tailgate: the point at which processed natural gas and NGLs leave a processing facility for transportation to end-user markets.
TBtu: one trillion British Thermal Units.
Tcf: one trillion cubic feet.

Throughput: the volume of products, such as crude oil, natural gas or water, transported or passing through a pipeline, plant, terminal or other facility during a particular period.
Uncommitted shippers (or walk-up shippers): customers that have not signed long-term shipper contracts and have rights under the FERC tariff as to rates and capacity allocation that are different than long-term committed shippers.
Volumetric fee contracts: volumetric fee contracts generally obligate a customer to pay fees based upon the extent to which such customer utilizes our assets for midstream energy services. Unlike firm fee contracts, under volumetric fee contracts our customers are not generally required to pay a charge to reserve an agreed upon amount of capacity and/or deliverability.
Wellhead: the equipment at the surface of a well that is used to control the well's pressure; also, the point at which the hydrocarbons and water exit the ground.
Working gas: the volume of gas in the storage reservoir that is in addition to the cushion or base gas. It may or may not be completely withdrawn during any particular withdrawal season. Conditions permitting, the total working capacity could be used more than once during any season.
Working gas storage capacity: the maximum volume of natural gas that can be cost-effectively injected into a storage facility and extracted during the normal operation of the storage facility. Effective working gas storage capacity excludes base gas and non-cycling working gas.
X/d: the applicable measurement metric per day. For example, MMcf/d means one million cubic feet per day.

PART 1—FINANCIAL INFORMATION
Item 1. Financial Statements
TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	March 31, 2016	December 31, 2015
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$2,885	$1,611
Accounts receivable, net	53,330	57,757
Gas imbalances	552	1,227
Inventories	13,739	13,793
Prepayments and other current assets	2,883	2,835
Total Current Assets	73,389	77,223
Property, plant and equipment, net	2,017,138	2,025,018
Goodwill	343,288	343,288
Intangible asset, net	95,795	96,546
Derivative asset at fair value	37,014	—
Deferred financing costs, net	6,102	5,105
Deferred charges and other assets	14,046	14,894
Total Assets	$2,586,772	$2,562,074
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities:		
Accounts payable (including $10,554 at December 31, 2015 related to variable interest entities)	$17,794	$22,218
Accounts payable to related parties	4,435	7,852
Gas imbalances	935	1,605
Derivative liabilities at fair value	44	—
Accrued taxes	19,450	13,844
Accrued liabilities	6,520	10,019
Deferred revenue	33,823	26,511
Other current liabilities	6,969	6,880
Total Current Liabilities	89,970	88,929
Long-term debt	1,200,000	753,000
Other long-term liabilities and deferred credits	4,904	5,143
Total Long-term Liabilities	1,204,904	758,143
Commitments and Contingencies		
Equity:		
Common unitholders (67,499,543 and 60,644,232 units issued and outstanding at March 31, 2016 and December 31, 2015, respectively)	1,882,611	1,618,766
General partner (834,391 units issued and outstanding at March 31, 2016 and December 31, 2015)	(624,511)	(348,841)
Total Partners' Equity	1,258,100	1,269,925
Noncontrolling interests	$33,798	$445,077
Total Equity	$1,291,898	$1,715,002
Total Liabilities and Equity	$2,586,772	$2,562,074

The accompanying notes are an integral part of these condensed consolidated financial statements.
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TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended March 31,	
	2016	2015
	(in thousands, except per unit amounts)	
Revenues:		
Crude oil transportation services	$94,572	$50,381
Natural gas transportation services	29,280	32,148
Sales of natural gas, NGLs, and crude oil	13,926	21,869
Processing and other revenues	7,627	10,277
Total Revenues	145,405	114,675
Operating Costs and Expenses:		
Cost of sales (exclusive of depreciation and amortization shown below)	13,568	19,593
Cost of transportation services (exclusive of depreciation and amortization shown below)	16,156	10,715
Operations and maintenance	12,477	9,575
Depreciation and amortization	21,692	20,605
General and administrative	13,016	12,689
Taxes, other than income taxes	7,506	11,297
Loss on sale of assets	—	4,483
Total Operating Costs and Expenses	84,415	88,957
Operating Income	60,990	25,718
Other (Expense) Income:		
Interest expense, net	(7,499)	(3,440)
Unrealized loss on derivative instrument	(8,946)	—
Other income, net	566	712
Total Other Expense	(15,879)	(2,728)
Net income	45,111	22,990
Net (income) loss attributable to noncontrolling interests	(1,041)	9,329
Net income attributable to partners	$44,070	$32,319
Allocation of income to the limited partners:		
Net income attributable to partners	$44,070	$32,319
General partner interest in net income	(20,353)	(7,438)
Common and subordinated unitholders' interest in net income	23,717	24,881
Basic net income per common and subordinated unit	$0.35	$0.47
Diluted net income per common and subordinated unit	$0.35	$0.46
Basic average number of common and subordinated units outstanding	66,967	52,727
Diluted average number of common and subordinated units outstanding	67,807	53,994

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

TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Cash Flows from Operating Activities:		
Net income	$45,111	$22,990
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	22,870	21,557
Noncash compensation expense	1,166	1,527
Noncash change in fair value of derivative financial instruments	8,990	(90)
Loss on sale of assets	—	4,483
Changes in components of working capital:		
Accounts receivable and other	5,800	(5,678)
Gas imbalances	566	143
Inventories	(508)	(2,754)
Accounts payable and accrued liabilities	(2,196)	6,546
Deferred revenue	7,204	106
Other operating, net	(246)	(191)
Net Cash Provided by Operating Activities	88,757	48,639
Cash Flows from Investing Activities:		
Capital expenditures	(17,545)	(13,300)
Acquisition of Pony Express membership interest	(49,118)	(700,000)
Other investing, net	25	(311)
Net Cash Used in Investing Activities	(66,638)	(713,611)
Cash Flows from Financing Activities:		
Distributions to unitholders	(59,040)	(28,294)
Acquisition of Pony Express membership interest	(425,882)	—
Contributions from noncontrolling interests	7,152	2,379
Distributions to noncontrolling interests	(1,793)	(1,416)
Borrowings under revolving credit facility, net	447,000	139,000
Proceeds from public offering, net of offering costs	12,636	551,949
Other financing, net	(918)	1,363
Net Cash (Used in) Provided by Financing Activities	(20,845)	664,981
Net Change in Cash and Cash Equivalents	1,274	9
Cash and Cash Equivalents, beginning of period	1,611	867
Cash and Cash Equivalents, end of period	$2,885	$876
Schedule of Noncash Investing and Financing Activities:		
Property, plant and equipment acquired via the cash management agreement with Tallgrass Development, LP	$—	$72,407

The accompanying notes are an integral part of these condensed consolidated financial statements.
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TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(UNAUDITED)

	Limited Partners		General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
	Common	Subordinated				
	(in thousands)					
Balance at January 1, 2016	$1,618,766	$ —	$(348,841)	$1,269,925	$ 445,077	$1,715,002
Net income	23,717	—	20,353	44,070	1,041	45,111
Issuance of units to public, net of offering costs	12,636	—	—	12,636	—	12,636
Noncash compensation expense	1,869	—	—	1,869	—	1,869
Distributions to unitholders	(42,984)	—	(16,056)	(59,040)	—	(59,040)
Acquisition of additional 31.3% membership interest in Pony Express	268,607	—	(279,967)	(11,360)	(417,679)	(429,039)
Contributions from noncontrolling interest	—	—	—	—	7,152	7,152
Distributions to noncontrolling interest	—	—	—	—	(1,793)	(1,793)
Balance at March 31, 2016	$1,882,611	$ —	$(624,511)	$1,258,100	$ 33,798	$1,291,898

	Limited Partners		General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
	Common	Subordinated				
	(in thousands)					
Balance at January 1, 2015	$800,333	$ 274,133	$(35,743)	$1,038,723	$ 756,428	$1,795,151
Net income (loss)	19,701	5,180	7,438	32,319	(9,329)	22,990
Issuance of units to public, net of offering costs	551,949	—	—	551,949	—	551,949
Noncash compensation expense	2,933	—	—	2,933	—	2,933
Distributions to unitholders	(15,925)	(7,857)	(4,512)	(28,294)	—	(28,294)
Contributions from noncontrolling interest	—	—	—	—	2,379	2,379
Distributions to noncontrolling interest	—	—	—	—	(2,156)	(2,156)
Acquisition of additional 33.3% Pony Express membership interest	—	—	(324,328)	(324,328)	(375,672)	(700,000)
Conversion of subordinated units	271,456	(271,456)	—	—	—	—
Balance at March 31, 2015	$1,630,447	$ —	$(357,145)	$1,273,302	$ 371,650	$1,644,952

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

TALLGRASS ENERGY PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Description of Business

Tallgrass Energy Partners, LP ("TEP" or the "Partnership") is a publicly traded, growth-oriented limited partnership formed to own, operate, acquire and develop midstream energy assets in North America. "We," "us," "our" and similar terms refer to TEP together with its consolidated subsidiaries. We currently provide crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which owns a crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma that includes a lateral in Northeast Colorado that commences in Weld County, Colorado, and interconnects with the pipeline just east of Sterling, Colorado (the "Pony Express System"). We provide natural gas transportation and storage services for customers in the Rocky Mountain and Midwest regions of the United States through the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system located in Colorado, Kansas, Missouri, Nebraska and Wyoming (the "TIGT System"), and a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Nebraska (the "Trailblazer Pipeline"). As discussed in Note 14 – Subsequent Events, we recently acquired a membership interest in Rockies Express Pipeline LLC ("REX"), a Delaware limited liability company engaged in the ownership and operation of the Rockies Express Pipeline, a FERC-regulated natural gas pipeline transportation system, traversing an area from the Rocky Mountain Region to the Appalachian Mountain Region. We also provide services for customers in Wyoming at the Casper and Douglas natural gas processing facilities and the West Frenchie Draw natural gas treating facility (collectively, the "Midstream Facilities"), and NGL transportation services in Northeast Colorado. We perform water business services in Colorado and Texas through BNN Water Solutions, LLC ("Water Solutions"). Our operations are strategically located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg, Powder River, Wind River, Permian and Hugoton-Anadarko Basins and the Niobrara, Mississippi Lime, Eagle Ford and Bakken shale formations.

Our reportable business segments are:

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

The table below summarizes our equity ownership as of March 31, 2016:

Unit Holder	Limited Partner Common Units	General Partner Units	Percentage of Outstanding Limited Partner Common Units	Percentage of Outstanding Common and General Partner Units
Public Unitholders	34,626,063	—	51.30 %	50.67 %
Tallgrass Equity, LLC	20,000,000	—	29.63 %	29.27 %
Tallgrass Development, LP	12,873,480	—	19.07 %	18.84 %
Tallgrass MLP GP, LLC [1]	—	834,391	—	1.22 %
Total	67,499,543	834,391	100.00 %	100.00 %

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

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2. Summary of Significant Accounting Policies
Basis of Presentation
These condensed consolidated financial statements and related notes for the three months ended March 31, 2016 and 2015 were prepared in accordance with the accounting principles contained in the Financial Accounting Standards Board's Accounting Standards Codification, the single source of generally accepted accounting principles in the United States of America ("GAAP") for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP for annual periods. The condensed consolidated financial statements for the three months ended March 31, 2016 and 2015 include all normal, recurring adjustments and disclosures that we believe are necessary for a fair statement of the results for the interim periods. In this report, the Financial Accounting Standards Board is referred to as the FASB and the FASB Accounting Standards Codification is referred to as the Codification or ASC. Certain prior period amounts have been reclassified to conform to the current presentation.
Our financial results for the three months ended March 31, 2016 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2016. The accompanying condensed consolidated interim financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2015 ("2015 Form 10-K") filed with the United States Securities and Exchange Commission (the "SEC") on February 17, 2016.
The condensed consolidated financial statements include the accounts of TEP and its subsidiaries and controlled affiliates. Significant intra-entity items have been eliminated in the presentation. Prior to January 1, 2016, Pony Express participated in a cash management agreement with Tallgrass Development, LP ("TD"), which currently holds a 2.0% common membership interest in Pony Express, under which cash balances were swept periodically and recorded as loans from Pony Express to TD. Effective January 1, 2016, Pony Express entered into a cash management agreement with TEP.
Net income or loss from consolidated subsidiaries that are not wholly-owned by TEP is attributed to TEP and noncontrolling interests. This is done in accordance with substantive profit sharing arrangements, which generally follow the allocation of cash distributions and may not follow the respective ownership percentages held by TEP. Concurrent with TEP's acquisition of an initial 33.3% membership interest in Pony Express effective September 1, 2014, TEP, TD, and Pony Express entered into the Second Amended and Restated Limited Liability Agreement of Tallgrass Pony Express Pipeline, LLC ("the Second Amended Pony Express LLC Agreement"), which provided TEP a minimum quarterly preference payment of $16.65 million (prorated to approximately $5.4 million for the quarter ended September 30, 2014) through the quarter ended September 30, 2015. Effective March 1, 2015 with TEP's acquisition of an additional 33.3% membership interest in Pony Express, the Second Amended Pony Express LLC Agreement was further amended (as amended, "the Pony Express LLC Agreement") to increase the minimum quarterly preference payment to $36.65 million (prorated to approximately $23.5 million for the quarter ended March 31, 2015) and extend the term of the preference period through the quarter ending December 31, 2015. The Pony Express LLC Agreement provides that the net income or loss of Pony Express be allocated, to the extent possible, consistent with the allocation of Pony Express cash distributions. Under the terms of the Pony Express LLC Agreement, Pony Express distributions and net income for periods beginning after December 31, 2015 are attributed to TEP and its noncontrolling interests in accordance with the respective ownership interests.
A variable interest entity ("VIE") is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has a variable interest that could be significant to the VIE and the power to direct the activities that most significantly impact the entity's economic performance. We have presented separately in our condensed consolidated balance sheets, to the extent material, the assets of our consolidated VIE that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of our consolidated VIE for which creditors do not have recourse to our

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

Use of Estimates
Certain amounts included in or affecting these condensed 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.
New Accounting Pronouncements
Accounting Standards Update ("ASU") No. 2014-09, "Revenue from Contracts with Customers (Topic 606)"
In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606). ASU 2014-09 provides a comprehensive and converged set of principles-based revenue recognition guidelines which supersede the existing industry and transaction-specific standards. The core principle of the new guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, entities must apply a five step process to (1) identify the contract with a customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation. ASU 2014-09 also mandates disclosure of sufficient information to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The disclosure requirements include qualitative and quantitative information about contracts with customers, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract.
The amendments in ASU 2014-09 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. Early application is permitted for annual reporting periods beginning after December 15, 2016. We are currently evaluating the impact of ASU 2014-09.
ASU No. 2014-12, "Compensation - Stock Compensation (Topic 718), Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period"
In June 2014, the FASB issued ASU No. 2014-12, Compensation - Stock Compensation (Topic 718), Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. ASU 2014-12 provides explicit guidance on accounting for share-based payments requiring a specific performance target to be achieved in order for employees to become eligible to vest in the awards when that performance target may be achieved after the requisite service period for the award. The ASU requires that such performance targets be treated as a performance condition, and should not be reflected in the estimate of the grant-date fair value of the award. Instead, compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved.
ASU 2014-12 is effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. The adoption of ASU 2014-12 did not have a material impact on our financial position and results of operations.
ASU No. 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis"
In February 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810) - Amendments to the Consolidation Analysis. ASU 2015-02 will change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. ASU 2015-02 will modify the evaluation of whether limited partnerships and other similar legal entities are considered VIEs or voting interest entities, eliminate the presumption that a general partner should consolidate a limited partnership, and change certain aspects of the consolidation analysis for reporting entities that are involved with VIEs, particularly for those with fee arrangements and related party relationships.

The amendments in ASU 2015-02 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2015. The adoption of ASU 2015-02 did not have a material impact on our financial position and results of operations.

ASU No. 2015-11, "Inventory (Topic 330): Simplifying the Measurement of Inventory"
In July 2015, the FASB issued ASU No. 2015-11, Inventory (Topic 330), Simplifying the Measurement of Inventory. ASU 2015-11 establishes a "lower of cost and net realizable value" model for the measurement of most inventory balances. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation.
The amendments in ASU 2015-11 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2016. Early adoption is permitted. We are currently evaluating the impact of ASU 2015-11.
ASU No. 2015-16, "Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments"
In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments. ASU 2015-16 simplifies the accounting for measurement-period adjustments for provisional amounts recognized in a business combination by eliminating the requirement for an acquirer to retrospectively account for measurement-period adjustments. Under the updated guidance, the acquirer must recognize adjustments in the reporting period in which the adjustment amounts are determined and the effect on earnings as a result of the change to the provisional amounts must be calculated as if the accounting had been completed at the acquisition date.
The amendments in ASU 2015-16 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2015. The adoption of ASU 2015-16 did not have a material impact on our financial position and results of operations.
ASU No. 2016-02, "Leases (Topic 842)"
In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). ASU 2016-02 provides a comprehensive update to the lease accounting topic in the Codification intended to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The amendments in ASU 2016-02 include a revised definition of a lease as well as certain scope exceptions. The changes primarily impact lessee accounting, while lessor accounting is largely unchanged from previous GAAP.
The amendments in ASU 2016-02 are effective for public entities for annual reporting periods beginning after December 15, 2018, and for interim periods within that reporting period. Early application is permitted. We are currently evaluating the impact of ASU 2016-02.
ASU No. 2016-08, "Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net)"
In March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net). ASU 2016-08 provides further clarification of the guidance in ASU 2014-09 with respect to principal versus agent considerations and are intended to improve the operability and understandability of the implementation guidance provided in ASU 2014-09.
The amendments in ASU 2016-08 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. Early application is permitted for annual reporting periods beginning after December 15, 2016. We are currently evaluating the impact of ASU 2016-08.
ASU No. 2016-09, "Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting"
In March 2016, the FASB issued ASU No. 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. ASU 2016-09 simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. Among other changes, ASU 2016-09 allows an entity to make an entity-wide accounting policy election to either estimate the number of awards expected to vest (consistent with current GAAP) or account for forfeitures when they occur.
The amendments in ASU 2016-09 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2016. Early adoption is permitted. We are currently evaluating the

impact of ASU 2016-09.

3. Acquisitions

Acquisition of Additional 31.3% Membership Interest in Pony Express

Effective January 1, 2016, TEP acquired an additional 31.3% membership interest in Pony Express in exchange for cash consideration of $475 million and 6,518,000 TEP common units (valued at approximately $268.6 million based on the December 31, 2015 closing price of 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 98.0%. As part of the transaction, TD granted us an 18 month call option to repurchase 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. 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 have not been recast to reflect the additional 31.3% membership interest. The transaction resulted in a deemed distribution to our general partner as discussed further in Note 9 – Partnership Equity and Distributions.

Cash outflows to acquire an additional noncontrolling interest in Pony Express are classified as an investing activity in the accompanying condensed 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 three months ended March 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.

TEP Acquisition of BNN Western, LLC

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

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

TEP's unaudited pro forma revenue and net income attributable to partners for the three months ended March 31, 2015 is presented below as if the acquisition of Western had been completed on January 1, 2015:

	Three Months Ended March 31, 2015
	(in thousands)
Revenue	$ 115,147
Net income attributable to partners	$ 32,483

The pro forma financial information is not necessarily indicative of what the actual results of operations or financial position of TEP would have been if the transactions had in fact occurred on the date or for the period indicated, nor do they purport to project the results of operations or financial position of TEP for any future periods or as of any date.

The pro forma financial information does not give effect to any cost savings, operating synergies, or revenue enhancements expected to result from the transactions or the costs to achieve these cost savings, operating synergies, and revenue enhancements. The pro forma revenue and net income includes adjustments to give effect to TEP's consolidated interest in the estimated results of operations of Western for the periods presented.

4. Related Party Transactions

We have no employees. TD, through its wholly-owned subsidiary Tallgrass Operations, LLC ("Tallgrass Operations"), provided and charged us for direct and indirect costs of services provided to us or incurred on our behalf including employee labor costs, information technology services, employee health and retirement benefits, and all other expenses necessary or appropriate to the conduct of our business. We recorded these costs on the accrual basis in the period in which TD incurred them. On May 17, 2013, in connection with the closing of TEP's initial public offering, TEP and its general partner entered into an Omnibus Agreement with TD and certain of its affiliates, including Tallgrass Operations (the "TEP Omnibus Agreement"). The TEP Omnibus Agreement provides that, among other things, TEP will reimburse TD and its affiliates for all expenses they incur and payments they make on TEP's behalf, including the costs of employee and director compensation and benefits as well as the cost of the provision of certain centralized corporate functions performed by TD, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology and human resources in each case to the extent reasonably allocable to TEP.

There was no interest income from TD recognized for the three months ended March 31, 2016. During the three months ended March 31, 2015 we recognized interest income from TD of $0.4 million on the receivable balance under the Pony Express cash management agreement in effect through December 31, 2015.

Totals of transactions with affiliated companies are as follows:

	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Cost of transportation services	$7,256	$4,358
Charges to TEP: [1]		
Property, plant and equipment, net	$899	$1,307
Operation and maintenance	$6,138	$5,423
General and administrative	$8,966	$9,256

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

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

	March 31, 2016	December 31, 2015
	(in thousands)	
Receivable from related parties:		
Rockies Express Pipeline LLC	$31	$ 15
Total receivable from related parties	$31	$ 15
Accounts payable to related parties:		
Tallgrass Operations, LLC	$4,385	$ 7,792
Tallgrass Equity, LLC	41	36
Deeprock Development, LLC	—	17
Rockies Express Pipeline LLC	9	7
Total accounts payable to related parties	$4,435	$ 7,852

Balances of gas imbalances with affiliated shippers are as follows:

	March 31, 2016	December 31, 2015
	(in thousands)	

Affiliate gas balance receivables	$7	$ 92
Affiliate gas balance payables	$102	$ 227

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5. Inventory

The components of inventory at March 31, 2016 and December 31, 2015 consisted of the following:

	March 31, 2016	December 31, 2015
	(in thousands)	
Crude oil	$4,194	$ 2,661
Materials and supplies	6,741	8,581
Natural gas liquids	303	395
Gas in underground storage	2,501	2,156
Total inventory	$13,739	$ 13,793

6. Property, Plant and Equipment

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

	March 31, 2016	December 31, 2015
	(in thousands)	
Crude oil pipelines	$1,177,790	$1,172,684
Natural gas pipelines	551,983	550,710
Processing and treating assets	255,663	254,073
Water business assets	82,608	81,098
General and other	80,660	69,181
Construction work in progress	21,255	30,699
Accumulated depreciation and amortization	(152,821)	(133,427)
Total property, plant and equipment, net	$2,017,138	$2,025,018

7. Risk Management

We occasionally enter into derivative contracts with third parties for the purpose of hedging exposures that accompany our normal business activities. Our normal business activities directly and indirectly expose us to risks associated with changes in the market price of crude oil and natural gas, among other commodities. For example, the risks associated with changes in the market price of natural gas include, among others (i) pre-existing or anticipated physical natural gas sales, (ii) natural gas purchases and (iii) natural gas system use and storage.

As discussed in Note 3 – Acquisitions, in conjunction with our acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016, TD granted us an 18 month call option to repurchase the newly issued 6,518,000 common units at a price of $42.50. 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 condensed consolidated balance sheets:

	Balance Sheet Location	March 31, 2016	December 31, 2015
		(in thousands)	
Call option derivative	Noncurrent assets	$37,014	$ —
Energy commodity derivative contracts	Current liabilities	$44	$ —

As of March 31, 2016, the fair value shown for commodity contracts was comprised of derivative volumes for short natural gas fixed-price swaps totaling 0.4 Bcf. As of December 31, 2015 there were no derivative contracts outstanding.

Effect of Derivative Contracts in the Statements of Income

The following table summarizes the impact of derivative contracts for the three months ended March 31, 2016 and 2015:

	Location of gain (loss) recognized in income on derivatives	Amount of gain (loss) recognized in income on derivatives Three Months Ended March 31, 2016	2015
		(in thousands)	
Derivatives not designated as hedging contracts:			
Call option derivative	Unrealized loss on derivative instrument	$ (8,946)	$ —
Energy commodity derivative contracts	Sales of natural gas, NGLs, and crude oil	$ (44)	$ 90

Credit Risk

We have counterparty credit risk as a result of our use of derivative contracts. Counterparties to our energy commodity derivatives consist of 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 is TD. Settlement of the call option derivative, if exercised, will require TEP to make a cash payment to TD in exchange for return of the common units.

Our over-the-counter swaps are entered into with counterparties outside central trading organizations such as futures, options or stock exchanges. These contracts are with financial institutions with investment grade credit ratings. While we enter into derivative transactions principally with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future. As of March 31, 2016, the fair value of our commodity derivative contracts was a liability, resulting in no credit exposure from TEP's counterparties as of that date.

As of March 31, 2016 and December 31, 2015, we did not have any outstanding letters of credit or cash in margin accounts in support of our hedging of commodity price risks associated with the sale of natural gas nor did we have any margin deposits with counterparties associated with energy commodity contract positions.

Fair Value

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

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

Certain OTC derivative contracts trade in less liquid markets with limited pricing information; as such, the determination of fair value for these derivative contracts is inherently more difficult. Such contracts are classified within Level 3 of the fair value hierarchy. The valuations of these less liquid OTC derivatives are typically impacted by Level 1 and/or Level 2 inputs that can be observed in the market, as well as unobservable Level 3 inputs. Use of a different valuation model or different valuation input values could produce a significantly different estimate of fair value. However, derivative contracts valued using inputs unobservable in active markets are generally not material to our financial statements. When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management's best estimate is used.

The call option granted by TD is valued using a Black-Scholes option pricing model. Key inputs to the valuation model include the term of the option, risk free rate, the exercise price and current market price, expected volatility and expected distribution yield of the underlying units. The call option valuation is classified within Level 2 of the fair value hierarchy as the value is based on significant observable inputs.

The following table summarizes the fair value measurements of our derivative contracts as of March 31, 2016 based on the fair value hierarchy established by the Codification:

	Total	Asset Fair Value Measurements Using Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(in thousands)			
As of March 31, 2016				
Call option derivative	$37,014	$ —	$ 37,014	$ —

	Total	Liability Fair Value Measurements Using Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(in thousands)			
As of March 31, 2016				
Energy commodity derivative contracts	$44	$ —	$ 44	$ —

8. Long-term Debt

Revolving Credit Facility

Effective January 4, 2016, in connection with the acquisition of an additional 31.3% membership interest in Pony Express, TEP exercised the committed accordion feature to increase the total capacity of the revolving credit facility from $1.1 billion to $1.5 billion. As discussed in Note 14 – Subsequent Events, effective May 6, 2016 we amended the revolving credit facility to increase the total capacity to $1.75 billion.

The following table sets forth the available borrowing capacity under our revolving credit facility as of March 31, 2016 and December 31, 2015:

	March 31, 2016	December 31, 2015
	(in thousands)	
Total capacity under the revolving credit facility	$1,500,000	$1,100,000
Less: Outstanding borrowings under the revolving credit facility	(1,200,000)	(753,000)
Available capacity under the revolving credit facility	$300,000	$347,000

The revolving credit facility contains various covenants and restrictive provisions that, among other things, limit or restrict our ability (as well as the ability of our restricted subsidiaries) to incur or guarantee additional debt, incur certain liens on assets, dispose of assets, make certain distributions (including distributions from available cash, if a default or event of default under the credit agreement then exists or would result from making such a distribution), change the nature of our business, engage in certain mergers or make certain investments and acquisitions, enter into non-arms-length transactions with affiliates and designate certain subsidiaries as "Unrestricted Subsidiaries." In

addition, we are required to maintain a consolidated leverage ratio of not more than 4.75 to 1.00 (which will be increased to 5.25 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and a consolidated interest coverage ratio of not less than 2.50 to 1.00. As of March 31, 2016, we are in compliance with the covenants required under the revolving credit facility.
The unused portion of the revolving credit facility is subject to a commitment fee, which ranges from 0.300% to 0.500%, based on our total leverage ratio. As of March 31, 2016, the weighted average interest rate on outstanding borrowings was 2.20%. During the three months ended March 31, 2016, our weighted average effective interest rate, including the interest on outstanding borrowings, commitment fees, and amortization of deferred financing costs, was 2.48%.

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 condensed consolidated balance sheets as of March 31, 2016 and December 31, 2015, but for which fair value is disclosed:

	Fair Value				
	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total	Carrying Amount
	(in thousands)				
March 31, 2016	$—	$ 1,200,000	$ —	$1,200,000	$1,200,000
December 31, 2015	$—	$ 753,000	$ —	$753,000	$753,000

The long-term debt borrowed under the revolving credit facility is carried at amortized cost. As of March 31, 2016 and December 31, 2015, the fair value approximates the carrying amount for the borrowings under the revolving credit facility using a discounted cash flow analysis. We are not aware of any factors that would significantly affect the estimated fair value subsequent to March 31, 2016.

9. Partnership Equity and Distributions

Equity Distribution Agreement

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

During the three months ended March 31, 2016, we issued and sold 337,311 common units with a weighted average sales price of $38.17 per unit under our equity distribution agreement for net cash proceeds of approximately $12.6 million (net of approximately $240,000 in commissions and professional service expenses). We used the net cash proceeds for general partnership purposes. At March 31, 2016, approximately $83.1 million in aggregate offering price remained available to be issued and sold under the equity distribution agreement. Subsequent to March 31, 2016, we issued and sold an additional 2,180,681 common units with a weighted average sales price of $37.93 per unit under our equity distribution agreement for net cash proceeds of approximately $81.9 million (net of approximately $830,000 in commissions and professional service expenses). We used the net cash proceeds for general partnership purposes.

Tallgrass Development Purchase Program

On February 17, 2016, TEP and Tallgrass Energy GP, LP ("TEGP") announced that the Board of Directors of Tallgrass Energy Holdings, LLC, the sole member of TEGP's general partner and the general partner of TD, has authorized an equity purchase program under which TD may initially purchase up to an aggregate of $100 million of the outstanding Class A shares of TEGP or the outstanding common units of TEP. TD may purchase Class A shares or Common Units from time to time on the open market or in negotiated purchases. The timing and amounts of any such purchases will be subject to market conditions and other factors, and will be in accordance with applicable securities laws and other legal requirements. The purchase plan does not obligate TD to acquire any specific number of Class A shares or Common Units and may be discontinued at any time. No purchases were made under this program during the three months ended March 31, 2016.

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

Our partnership agreement requires us to distribute our available cash, as defined in the partnership agreement, to unitholders of record on the applicable record date within 45 days after the end of each quarter. The following table shows the distributions for the periods indicated:

		Distributions				
		Limited Partners	General Partner			
Three Months Ended	Date Paid	Common and Subordinated Units	Incentive Distribution Rights	General Partner Units	Total	Distributions per Limited Partner Unit
		(in thousands, except per unit amounts)				
March 31, 2016	May 13, 2016 [(1)]	$48,238	$19,816	$ 830	$68,884	$ 0.7050
December 31, 2015	February 12, 2016	42,984	15,332	724	59,040	0.6400
September 30, 2015	November 13, 2015	36,347	11,567	660	48,574	0.6000
June 30, 2015	August 14, 2015	35,135	10,418	627	46,180	0.5800
March 31, 2015	May 14, 2015	31,322	6,934	530	38,786	0.5200

(1) The distribution announced on April 12, 2016 for the first quarter of 2016 will be paid on May 13, 2016 to unitholders of record at the close of business on April 21, 2016.

Other Contributions and Distributions

During the three months ended March 31, 2016, TEP was deemed to have made a noncash capital distribution of $280.0 million to the general partner, which represents the excess purchase price over the carrying value of the additional 31.3% membership interest in Pony Express acquired effective January 1, 2016. See Note 3 - Acquisitions for additional information regarding the transaction.

During the three months ended March 31, 2015, TEP was deemed to have made a noncash capital distribution of $324.3 million to the general partner, which represents the excess purchase price over the carrying value of the additional 33.3% membership interest in Pony Express acquired effective March 1, 2015.

10. Net Income per Limited Partner Unit

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

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

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

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

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit reflects the potential dilution of common equivalent units that could occur if equity participation units are converted into common units.

The following table illustrates the Partnership's calculation of net income per common and subordinated unit for the three months ended March 31, 2016 and 2015:

	Three Months Ended March 31,	
	2016	2015
	(in thousands, except per unit amounts)	
Net income	$45,111	$22,990
Net (income) loss attributable to noncontrolling interests	(1,041)	9,329
Net income attributable to partners	44,070	32,319
General partner interest in net income	(20,353)	(7,438)
Net income available to common and subordinated unitholders	$23,717	$24,881
Basic net income per common and subordinated unit	$0.35	$0.47
Diluted net income per common and subordinated unit	$0.35	$0.46
Basic average number of common and subordinated units outstanding	66,967	52,727
Equity Participation Unit equivalent units	840	1,267
Diluted average number of common and subordinated units outstanding	67,807	53,994

11. Regulatory Matters

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

TIGT

General Rate Case Filing – FERC Docket RP16-137

On October 30, 2015, TIGT filed a general rate case with the FERC pursuant to Section 4 of the NGA. The rate case proposed a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by TIGT. In addition, TIGT proposed certain changes to the transportation rate design of its system to replace the current rate zone structure with a single "postage stamp" rate. TIGT also proposed new incremental charges, including (i) a charge for deliveries made to points without certain electronic flow measurement equipment, and (ii) a Cost Recovery Mechanism ("CRM") charge to completely or partially reimburse TIGT for certain costs it incurred to maintain system safety, environmental compliance and reliability. TIGT also proposed to replace its fixed fuel and lost and unaccounted for ("FL&U") charge with a FL&U tracker that would compensate TIGT for its actual FL&U expenses and adjust each year to reflect the previous period's under/over collection and the forecasted FL&U expense for the upcoming period. TIGT also proposed to implement a power cost tracker to recover the actual power costs incurred by

TIGT to power its compressors. Finally, TIGT proposed certain revisions to its FERC Gas Tariff addressing a number of other rate and non-rate matters. Under the NGA and the FERC's regulations, TIGT's shippers and other interested parties, including the FERC's Trial Staff, have a right to challenge any aspect of TIGT's rate case filing. Accordingly, numerous TIGT customers have protested aspects of TIGT's NGA Section 4 rate filing.

On November 30, 2015, the FERC issued an order accepting and suspending the proposed rates and a majority of the proposed tariff records to be effective upon motion May 1, 2016, subject to refund, certain modifications to TIGT's proposed CRM charge, and the outcome of an evidentiary hearing before a FERC Administrative Law Judge (the "Suspension Order"). In the Suspension Order, the FERC also accepted two tariff records related to force majeure events and reservation charge crediting to be effective December 1, 2015, subject to certain modifications. On December 21, 2015, TIGT made a compliance filing with the FERC to modify TIGT's proposed CRM charge and update the tariff records related to force majeure events and reservation charge crediting as directed by the FERC in the Suspension Order. No comments or protests were filed in response to the compliance filing and FERC accepted the compliance filing on February 1, 2016. The FERC Administrative Law Judge assigned to the proceeding has issued an order establishing the procedural schedule and TIGT, the FERC's Trial Staff, and other participants that successfully intervened are actively participating in the litigated proceeding to address those rate and tariff matters set for hearing by the FERC in its Suspension Order. On March 22, 2016, a Settlement Judge was appointed in the case to assist the participants explore the possibility of settlement. On March 31, 2016, the FERC issued an order denying a request for rehearing with respect to its challenge of TIGT's proposed CRM. The FERC granted in part and denied in part a motion for technical conference, and denied a rehearing request made in the alternative on this issue, and retained for resolution through hearing the pro forma tariff records related to TIGT's proposed charge at delivery points lacking electronic flow measurement and removed from hearing the other issues related to the pro forma tariff records. Whether such issues will be resolved through technical conference is pending. The FERC also directed TIGT to provide additional information related to certain pro forma tariff records, which TIGT filed on April 14, 2016. TIGT has reached an agreement in principle with customers representing a majority of firm fee revenue on the TIGT System for the year ended December 31, 2015 to settle all rate related issues set for hearing in its existing FERC rate case, including the issues of a cost recovery mechanism and a non-Electronic Flow Measurement charge. The settlement remains subject to the final approval of the FERC.

Trailblazer

2016 Annual Fuel Tracker Filing – FERC Docket RP16-814-000

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.

12. Legal and Environmental Matters

Legal

In addition to the matters discussed below, we are a defendant in various lawsuits arising from the day-to-day operations of our business. Although no assurance can be given, we believe, based on our experiences to date, that the ultimate resolution of such routine items will not have a material adverse impact on our business, financial position, results of operations or cash flows. We have evaluated claims in accordance with the accounting guidance for contingencies that we deem both probable and reasonably estimable and, accordingly, had no reserve for legal claims as of March 31, 2016 or December 31, 2015.

Environmental, Health and Safety

We are subject to a variety of federal, state and local laws that regulate permitted activities relating to air and water quality, waste disposal, and other environmental matters. We believe that compliance with these laws will not have a material adverse impact on our business, cash flows, financial position or results of operations. However, there can be no assurances that future events, such as changes in existing laws, the promulgation of new laws, or the development of new facts or conditions will not cause us to incur significant costs. We had environmental reserves of $4.6 million and $4.8 million at March 31, 2016 and December 31, 2015, respectively.

TMID

Casper Plant, EPA Notice of Violation

In August 2011, the EPA and the Wyoming Department of Environmental Quality ("WDEQ") conducted an inspection of the Leak Detection and Repair ("LDAR") Program at the Casper Gas Plant in Wyoming. In September 2011, Tallgrass Midstream, LLC ("TMID") received a letter from the EPA alleging violations of the Standards of Performance of Equipment Leaks for Onshore Natural Gas Processing Plant requirements under the Clean Air Act. TMID received a letter from the EPA concerning settlement of this matter in April 2013 and received additional settlement communications from the EPA and Department of Justice beginning in July 2014. Settlement negotiations are continuing, including the expected inclusion of TIGT as a party to any possible settlement as a result of TIGT owning a compressor that is located adjacent to the Casper Gas Plant site.

Casper Mystery Bridge Superfund Site

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

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.

Trailblazer

Pipeline Integrity Management Program

In 2014 and 2015, Trailblazer conducted smart tool surveys and preliminary analysis on segments of its natural gas pipeline to evaluate the growth rate of corrosion downstream of compressor stations. Trailblazer currently believes that approximately 25 - 35 miles of pipe will likely need to be repaired or replaced in order for the pipeline to operate at its maximum allowable operating pressure of 1,000 pounds per square inch. Such repair or replacement will likely occur over a period of years, depending upon final assessment of corrosion growth rates and the remediation and repair plan implemented by Trailblazer. Trailblazer is currently operating at less than its current maximum allowable operating pressure, public notice of which was first provided in June 2014. The current pressure reduction is not expected to prevent Trailblazer from fulfilling its firm service obligations at existing subscription levels and to date it has not had a material adverse financial impact on TEP.

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

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

13. Reporting Segments

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

Crude Oil Transportation & Logistics

The Crude Oil Transportation & Logistics segment is engaged in the ownership and operation of the Pony Express System, which is a FERC-regulated crude oil pipeline serving the Bakken Shale and other nearby oil producing basins. The mainline portion of the Pony Express System was placed in service in October 2014. The Pony Express System also includes a lateral pipeline in Northeast Colorado, which interconnects with the Pony Express System just east of Sterling, Colorado and was placed in service in the second quarter of 2015.

Natural Gas Transportation & Logistics

The Natural Gas Transportation & Logistics segment is engaged in the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities that provide services to on-system customers (such as third-party LDCs), industrial users and other shippers.

Processing & Logistics

The Processing & Logistics segment is engaged in the ownership and operation of natural gas processing, treating and fractionation facilities that produce NGLs and residue gas that is sold in local wholesale markets or delivered into pipelines for transportation to additional end markets, as well as water business services provided primarily to the oil and gas exploration and production industry and the transportation of NGLs.

Corporate and Other

Corporate and Other includes corporate overhead costs that are not directly associated with the operations of our reportable segments, such as interest and fees associated with our revolving credit facility, public company costs, and equity-based compensation expense.

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

We consider Adjusted EBITDA our primary segment performance measure as we believe it is the most meaningful measure to assess our financial condition and results of operations as a public entity. We define Adjusted EBITDA, a non-GAAP measure, as net income excluding the impact of interest, income taxes, depreciation and amortization, non-cash income or loss related to derivative instruments, non-cash long-term compensation expense, impairment losses, gains or losses on asset or business disposals or acquisitions, gains or losses on the repurchase, redemption or early retirement of debt, and earnings from unconsolidated investments, but including the impact of distributions from unconsolidated investments.

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

Revenue:	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue
	(in thousands)					
Crude Oil Transportation & Logistics	$94,572	$—	$94,572	$50,381	$—	$50,381
Natural Gas Transportation & Logistics	30,987	(1,355)	29,632	33,610	(1,346)	32,264
Processing & Logistics	21,201	—	21,201	32,030	—	32,030
Corporate and Other	—	—	—	—	—	—
Total Revenue	$146,760	$(1,355)	$145,405	$116,021	$(1,346)	$114,675

Adjusted EBITDA:	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
	Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA
	(in thousands)					
Crude Oil Transportation & Logistics	$64,541	$1,345	$65,886	$25,506	$1,346	$26,852
Natural Gas Transportation & Logistics	17,152	(1,355)	15,797	19,246	(1,346)	17,900
Processing & Logistics	3,351	10	3,361	8,718	—	8,718
Corporate and Other	(1,352)	—	(1,352)	(635)	—	(635)
Reconciliation to Net Income:						
Add:						
Non-cash loss allocated to noncontrolling interest			—			9,377
Less:						
Interest expense, net of noncontrolling interest			(7,499)			(3,440)
Depreciation and amortization expense, net of noncontrolling interest			(21,967)			(20,533)
Non-cash (loss) gain related to derivative instruments			(8,990)			90
Non-cash compensation expense			(1,166)			(1,527)
Non-cash loss from asset sales			—			(4,483)
Net income attributable to partners			$44,070			$32,319

Capital Expenditures:	Three Months Ended March 31, 2016	2015
	(in thousands)	
Crude Oil Transportation & Logistics	$12,311	$6,480
Natural Gas Transportation & Logistics	2,133	3,865
Processing & Logistics	3,101	2,955
Corporate and Other	—	—
Total capital expenditures	$17,545	$13,300

Assets:	March 31, 2016	December 31, 2015
	(in thousands)	
Crude Oil Transportation & Logistics	$1,433,153	$1,439,418
Natural Gas Transportation & Logistics	698,745	706,576
Processing & Logistics	411,509	409,795
Corporate and Other	43,365	6,285
Total assets	$2,586,772	$2,562,074

14. Subsequent Events

Acquisition of a Membership Interest in Rockies Express Pipeline LLC

On March 29, 2016, TD's indirect wholly owned subsidiary Rockies Express Holdings, LLC ("REX Holdings") signed a purchase agreement (the "Purchase Agreement") with a unit of Sempra U.S. Gas and Power ("Sempra") to acquire Sempra's 25% membership interest in Rockies Express Pipeline LLC ("REX") for cash consideration of $440 million, subject to adjustment under the Purchase Agreement. A subsidiary of Phillips 66, which owns a 25% membership interest in REX, has waived its right to purchase its proportionate share of Sempra's 25% membership interest being sold to REX Holdings (the "Right of First Refusal") in exchange for Sempra and REX Holdings agreeing to certain modifications to the REX Limited Liability Company Agreement.

On April 28, 2016, we announced that TD offered us the right to assume the rights and obligations of REX Holdings under the Purchase Agreement. On May 6, 2016, TEP REX Holdings, LLC ("TEP REX"), an indirect wholly-owned subsidiary of the Partnership, and REX Holdings entered into an Assignment and Assumption Agreement pursuant to which REX Holdings assigned to TEP REX all of its rights under the Purchase Agreement and, in exchange, TEP REX assumed all of the rights and obligations of REX Holdings under the Purchase Agreement. Subsequently on May 6, 2016, TEP REX closed the purchase of a 25% membership interest in REX 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.

Revolving Credit Facility Increase

In connection with our acquisition of an interest in REX, we have amended our revolving credit facility to, among other things, increase the lender commitments from $1.5 billion to $1.75 billion effective May 6, 2016. As of May 6, 2016, TEP had approximately $1.4 billion of outstanding borrowings under its revolving credit facility.

Unregistered Sale of Equity Securities

On April 28, 2016, we issued an aggregate of 2,416,987 common units representing limited partnership interests in the Partnership for net cash proceeds of $90.0 million in a private placement transaction to certain funds managed by Tortoise Capital Advisors, L.L.C.

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

As used in this Quarterly Report, unless the context otherwise requires, "we," "us," "our," the "Partnership," "TEP" and similar terms refer to Tallgrass Energy Partners, LP, together with its consolidated subsidiaries. The term our "general partner" refers to Tallgrass MLP GP, LLC. References to "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 condensed consolidated financial statements and related notes thereto included elsewhere in this Quarterly Report. Additionally, the following discussion and analysis should be read in conjunction with our audited financial statements and notes thereto, the related "Management's Discussion and Analysis of Financial Condition and Results of Operations," the discussion of "Risk Factors" and the discussion of TEP's "Business" in our Annual Report on Form 10-K for the year ended December 31, 2015 (our "2015 Form 10-K") filed with the United States Securities and Exchange Commission (the "SEC") on February 17, 2016.

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

Cautionary Statement Regarding Forward-Looking Statements

This Quarterly Report and the documents incorporated by reference herein contain forward-looking statements concerning our operations, economic performance and financial condition. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as "could," "will," "may," "assume," "forecast," "position," "predict," "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 Quarterly Report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including guidance regarding our and TD's infrastructure programs, revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Quarterly Report. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- our ability to complete and integrate acquisitions from TD or from third parties, including our acquisition of a 25% membership interest in Rockies Express Pipeline LLC ("REX") that was completed in May 2016, our acquisition of water business assets in Weld County, Colorado that was completed in December 2015 and our purchase of an additional 31.3% membership interest in Tallgrass Pony Express Pipeline, LLC ("Pony Express") that was completed in January 2016;
- large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by third-party operators, processors and transporters;
- the demand for our services, including crude oil transportation services, natural gas transportation, storage and processing services and water business services;
- our ability to successfully implement our business plan;
- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;
-

the level of production of crude oil, natural gas and other hydrocarbons and the resultant market prices of crude oil, natural gas, NGLs, and other hydrocarbons;

- the availability and price of natural gas and crude oil, and fuels derived from both, to the consumer compared to the price of alternative and competing fuels;

- competition from the same and alternative energy sources;
- energy efficiency and technology trends;
- operating hazards and other risks incidental to transporting crude oil, transporting, storing and processing natural gas, and transporting, gathering and disposing of water produced in connection with hydrocarbon exploration and production activities;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- certain factors discussed elsewhere in this Quarterly Report.

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

Overview

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

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

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

Recent Developments

Distribution Announced

On April 12, 2016, we announced a cash distribution for the quarter ended March 31, 2016 of $0.705 per common unit. The distribution will be paid on May 13, 2016, to unitholders of record on April 21, 2016.

Acquisition of a Membership Interest in Rockies Express Pipeline LLC

On March 29, 2016, TD's indirect wholly owned subsidiary Rockies Express Holdings, LLC ("REX Holdings") signed a purchase agreement (the "Purchase Agreement") with a unit of Sempra U.S. Gas and Power ("Sempra") to acquire Sempra's 25% membership interest in REX for cash consideration of $440 million, subject to adjustment under the Purchase Agreement. A subsidiary of Phillips 66, which owns a 25% membership interest in REX, has waived its right to purchase its proportionate share of Sempra's 25% membership interest being sold to REX Holdings (the "Right of First Refusal") in exchange for Sempra and REX Holdings agreeing to certain modifications to the REX Limited Liability Company Agreement.

On April 28, 2016, we announced that TD offered us the right to assume the rights and obligations of REX Holdings under the Purchase Agreement. On May 6, 2016, TEP REX Holdings, LLC ("TEP REX"), an indirect wholly-owned subsidiary of the Partnership, and REX Holdings entered into an Assignment and Assumption Agreement pursuant to which REX Holdings assigned to TEP REX all of its rights under the Purchase Agreement and, in exchange, TEP REX assumed all of the rights and obligations of REX Holdings under the Purchase Agreement. Subsequently on May 6, 2016, TEP REX closed the purchase of a 25% membership interest in REX 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.

Revolving Credit Facility Increase

In connection with our acquisition of an interest in REX, we have amended our revolving credit facility to, among other things, increase the lender commitments from $1.5 billion to $1.75 billion effective May 6, 2016. As of May 6, 2016, TEP had approximately $1.4 billion of outstanding borrowings under its revolving credit facility.

Unregistered Sale of Equity Securities

On April 28, 2016, we issued an aggregate of 2,416,987 common units representing limited partnership interests in the Partnership for net cash proceeds of $90.0 million in a private placement transaction to certain funds managed by Tortoise Capital Advisors, L.L.C.

U.S. Crude Oil and Natural Gas Supply and Demand Dynamics

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.

Current Commodity Environment

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

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

The recent commodity price declines may also negatively impact the financial condition of our customers and could impact their ability to meet their financial obligations to us. As a result of the current environment, we have seen a number of bankruptcies and credit downgrades within the industry. As a result of credit downgrades, the percent of our revenue from customers with investment grade credit ratings fell to slightly below 50% during the three months ended March 31, 2016, as discussed further in Item 3.—Quantitative and Qualitative Disclosures About Market Risk.

Additionally, lower commodity prices generally lead to reduced utilization of our assets. For example, reduced utilization could result in increased deficiency balances held by customers of our Pony Express System. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment of our goodwill or long-lived assets due to the potential impact on our operations and cash flows.

How We Evaluate Our Operations

We evaluate our results using, among other measures, contract profile and volumes, operating costs and expenses, Adjusted EBITDA and Distributable Cash Flow. Adjusted EBITDA and Distributable Cash Flow are non-GAAP measures and are defined below.

Contract Profile and Volumes

Our results are driven primarily by the volume of crude oil transportation capacity, natural gas transportation and storage capacity, NGL transportation capacity, and water transportation, gathering and disposal capacity under firm fee contracts, as well as the volume of natural gas that we process and the fees assessed for such services.

Operating Costs and Expenses

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

Adjusted EBITDA and Distributable Cash Flow

Adjusted EBITDA and Distributable Cash Flow are non-GAAP supplemental financial measures that management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

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

We believe that the presentation of Adjusted EBITDA and Distributable Cash Flow provides useful information to investors in assessing our financial condition and results of operations. Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income, operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP, nor should Adjusted EBITDA and Distributable Cash Flow be considered alternatives to available cash, operating surplus, distributions of available cash from operating surplus or other definitions in our partnership agreement. Adjusted EBITDA and Distributable Cash Flow have important limitations as analytical tools because they exclude some but not all items that affect net income and net cash provided by operating activities. Additionally, because Adjusted EBITDA and Distributable Cash Flow may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Non-GAAP Financial Measures

We generally define Adjusted EBITDA as net income excluding the impact of interest, income taxes, depreciation and amortization, non-cash income or loss related to derivative instruments, non-cash long-term compensation expense, impairment losses, gains or losses on asset or business disposals or acquisitions, gains or losses on the repurchase, redemption or early retirement of debt, and earnings from unconsolidated investments, but including the impact of distributions from unconsolidated investments. We also use Distributable Cash Flow, which we generally define as Adjusted EBITDA, plus preferred distributions received from Pony Express in excess of its distributable cash flow attributable to our net interest and adjusted for deficiency payments received from or utilized by Pony Express shippers, less cash interest expense, maintenance capital expenditures, distributions to noncontrolling interests in excess of earnings allocated to noncontrolling interests, and certain cash reserves permitted by our partnership agreement, to analyze our performance. Maintenance capital expenditures are cash expenditures incurred (including expenditures for the construction or development of new capital assets) that we expect to maintain our long-term operating income or operating capacity. These expenditures typically include certain system integrity, compliance and safety improvements. As discussed in Note 2 – Summary of Significant Accounting Policies, prior to December 31, 2015, we received preferred distributions from Pony Express. Effective January 1, 2016 with our acquisition of an additional 31.3% membership interest in Pony Express, distributable cash flow from Pony Express is distributed pro rata based on ownership.

Pony Express collects deficiency payments for barrels committed by the customer to be transported in a month but not physically received for transport or delivered to the customers' agreed upon destination point. These deficiency payments are recorded as a deferred liability until the barrels are physically transported and delivered by TEP.

Earnings at Pony Express prior to December 31, 2015 were allocated between TEP and noncontrolling interests in accordance with a substantive profit sharing arrangement rather than pro rata by ownership. Distributions made by Pony Express to its noncontrolling interests reduce the Distributable Cash Flow available to TEP.

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

	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Reconciliation of Adjusted EBITDA to Net Income		
Net income attributable to partners	$44,070	$32,319
Add:		
Interest expense, net of noncontrolling interest	7,499	3,440
Depreciation and amortization expense, net of noncontrolling interest	21,967	20,533
Non-cash loss (gain) related to derivative instruments	8,990	(90)
Non-cash compensation expense	1,166	1,527
Non-cash loss from asset sales	—	4,483
Less:		
Non-cash loss allocated to noncontrolling interest	—	(9,377)
Adjusted EBITDA	$83,692	$52,835
Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Cash Provided by Operating Activities		
Net cash provided by operating activities	$88,757	$48,639
Add:		
Interest expense, net of noncontrolling interest	7,499	3,440
Other, including changes in operating working capital	(12,564)	756
Adjusted EBITDA	$83,692	$52,835
Add:		
Pony Express deficiency payments received, net	7,157	292
Less:		
Cash interest cost	(6,821)	(3,031)
Maintenance capital expenditures	(2,168)	(1,511)
Distributions to noncontrolling interest in excess of earnings	—	(2,103)
Distributable Cash Flow	$81,860	$46,482

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:

	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Reconciliation of Adjusted EBITDA to Operating Income in the Crude Oil Transportation & Logistics Segment (1)		
Operating income	$52,666	$14,273
Add:		
Depreciation and amortization expense, net of noncontrolling interest	12,918	11,233
Adjusted EBITDA attributable to noncontrolling interests	(1,043)	9,377
Less:		
Non-cash loss allocated to noncontrolling interest	—	(9,377)
Segment Adjusted EBITDA	$64,541	$25,506

Reconciliation of Adjusted EBITDA to Operating Income in the Natural Gas Transportation & Logistics Segment [1]		
Operating income	$10,664	$12,553
Add:		
Depreciation and amortization expense	5,878	6,071
Non-cash loss (gain) related to derivative instruments	44	(90)
Other income, net	566	712
Segment Adjusted EBITDA	$17,152	$19,246
Reconciliation of Adjusted EBITDA to Operating Income in the Processing & Logistics Segment [1]		
Operating income	$178	$1,054
Add:		
Depreciation and amortization expense, net of noncontrolling interest	3,171	3,229
Non-cash loss from asset sales	—	4,483
Adjusted EBITDA attributable to noncontrolling interests	2	(48)
Segment Adjusted EBITDA	$3,351	$8,718
Total Segment Adjusted EBITDA	$85,044	$53,470
Corporate general and administrative costs	(1,352)	(635)
Total Adjusted EBITDA	$83,692	$52,835

(1) Segment results as presented represent total operating income and Adjusted EBITDA, including intersegment activity, for the Crude Oil Transportation & Logistics, Natural Gas Transportation & Logistics, and Processing & Logistics segments. For reconciliations to the consolidated financial data, see Note 13 – Reporting Segments to the accompanying consolidated financial statements.

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Results of Operations

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

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
	(in thousands, except operating data)	
Revenues:		
Crude oil transportation services	$ 94,572	$ 50,381
Natural gas transportation services	29,280	32,148
Sales of natural gas, NGLs, and crude oil	13,926	21,869
Processing and other revenues	7,627	10,277
Total Revenues	145,405	114,675
Operating Costs and Expenses:		
Cost of sales (exclusive of depreciation and amortization shown below)	13,568	19,593
Cost of transportation services (exclusive of depreciation and amortization shown below)	16,156	10,715
Operations and maintenance	12,477	9,575
Depreciation and amortization	21,692	20,605
General and administrative	13,016	12,689
Taxes, other than income taxes	7,506	11,297
Loss on sale of assets	—	4,483
Total Operating Costs and Expenses	84,415	88,957
Operating Income	60,990	25,718
Other (Expense) Income:		
Interest expense, net	(7,499)	(3,440)
Unrealized loss on derivative instrument	(8,946)	—
Other income, net	566	712
Total Other Expense	(15,879)	(2,728)
Net income	45,111	22,990
Net (income) loss attributable to noncontrolling interests	(1,041)	9,329
Net income attributable to partners	$ 44,070	$ 32,319
Other Financial Data: [1]		
Adjusted EBITDA	$ 83,692	$ 52,835
Operating Data:		
Crude oil transportation average throughput (Bbls/d) [2]	291,274	165,409
Gas transportation firm contracted capacity (MMcf/d)	1,485	1,609
Natural gas processing inlet volumes (MMcf/d)	98	145

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

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

Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015

Revenues. Total revenues were $145.4 million for the three months ended March 31, 2016, compared to $114.7 million for the three months ended March 31, 2015, which represents an increase of $30.7 million, or 27%, in total revenues. The overall increase in revenue was largely driven by increased revenues of $44.2 million in the Crude Oil Transportation & Logistics segment, partially offset by decreased revenues of $10.8 million and $2.6 million in the Processing & Logistics and Natural Gas Transportation & Logistics segments, respectively, as discussed further below.

Operating costs and expenses. Operating costs and expenses were $84.4 million for the three months ended March 31, 2016 compared to $89.0 million for the three months ended March 31, 2015, which represents a decrease of $4.5 million, or 5%. The overall decrease in operating costs and expenses is primarily driven by decreased operating costs and expenses of $10.0 million and $0.7 million in the Processing & Logistics and Natural Gas Transportation & Logistics segments, respectively, partially offset by increased operating costs and expenses of $5.8 million in the Crude Oil Transportation & Logistics segment, as discussed further below.

Interest expense, net. Interest expense of $7.5 million for the three months ended March 31, 2016 was primarily composed of interest and fees associated with TEP's revolving credit facility. Interest expense of $3.4 million for the three months ended March 31, 2015 was primarily composed of interest and fees associated with TEP's revolving credit facility, partially offset by interest income of $0.4 million on the cash balance swept to TD under the Pony Express cash management agreement. The increase in interest and fees associated with TEP's revolving credit facility is primarily due to increased borrowings to fund a portion of our 2015 acquisitions and our recent acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016.

Unrealized loss on derivative instrument. Unrealized loss on derivative instrument of $8.9 million represents the change in fair value of the call option received from TD as part of the acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016. The call option grants TEP the right to repurchase the 6,518,000 common units issued to TD as a portion of the consideration for the acquisition at a price of $42.50.

Other income, net. Other income, net typically includes rental income, income earned from certain customers related to the capital costs we incurred to connect these customers to our system, and the allowance for funds used during construction at our regulated entities. Other income for the three months ended March 31, 2016 was $0.6 million compared to $0.7 million for the three months ended March 31, 2015.

Net (income) loss attributable to noncontrolling interests. Net income attributable to noncontrolling interests of $1.0 million for the three months ended March 31, 2016 primarily reflects the net income allocated to TD's 2% noncontrolling interest in Pony Express. Net loss attributable to noncontrolling interest of $9.3 million for the three months ended March 31, 2015 primarily reflects losses allocated to TD's 33.3% noncontrolling interest of Pony Express as a result of the income allocated to TEP as a result of the minimum quarterly preference payment received for the first quarter of 2015.

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

Segment Financial Data - Crude Oil Transportation & Logistics [1]	Three Months Ended March 31, 2016	2015
	(in thousands)	
Revenues:		
Crude Oil transportation services	$94,572	$50,381
Total revenues	94,572	50,381
Operating costs and expenses:		
Cost of transportation services	14,495	8,709
Operations and maintenance	3,831	1,415
Depreciation and amortization	12,639	11,233
General and administrative	5,034	5,155
Taxes, other than income taxes	5,907	9,596
Total operating costs and expenses	41,906	36,108
Operating income	$52,666	$14,273

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 13 – Reporting Segments to the accompanying condensed consolidated financial statements.

Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015

Revenues. Crude Oil Transportation & Logistics segment revenues were $94.6 million for the three months ended March 31, 2016, compared to $50.4 million for the three months ended March 31, 2015, which represents an increase of $44.2 million, or 88%, in segment revenues primarily due to $27.8 million of revenue from a full quarter of operations on the lateral in Northeast Colorado, which began commercial operations during the second quarter of 2015, and approximately $10.6 million related to the activation of one of our joint tariffs in the second quarter of 2015.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were $41.9 million for the three months ended March 31, 2016 compared to $36.1 million for the three months ended March 31, 2015, which represents an increase of $5.8 million, or 16%. The overall increase in operating costs and expenses was primarily driven by a $5.8 million increase in cost of transportation services, a $2.4 million increase in operations and maintenance costs, and a $1.4 million increase in depreciation and amortization, all primarily driven by the costs associated with a full quarter of operations on the lateral in Northeast Colorado, which began commercial operations during the second quarter of 2015. These increases were partially offset by a $3.7 million decrease in taxes, other than income taxes, due to lower property tax estimates for 2015 as a result of successful appeals with state taxing authorities on the assessed value of property, which lowered 2015 tax accruals beginning in the second quarter of 2015, partially offset by increased estimates for 2016 resulting from the lateral in Northeast Colorado that was placed into service during the second quarter of 2015.

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

Segment Financial Data - Natural Gas Transportation & Logistics [1]	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Revenues:		
Natural gas transportation services	$30,635	$33,494
Sales of natural gas, NGLs, and crude oil	348	105
Processing and other revenues	4	11
Total revenues	30,987	33,610
Operating costs and expenses:		
Cost of sales	1,146	74
Cost of transportation services	2,455	3,316
Operations and maintenance	5,880	5,740
Depreciation and amortization	5,878	6,071
General and administrative	3,788	4,261
Taxes, other than income taxes	1,176	1,595
Total operating costs and expenses	20,323	21,057
Operating income	$10,664	$12,553

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 13 – Reporting Segments to the accompanying condensed consolidated financial statements.

Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015

Revenues. Natural Gas Transportation & Logistics segment revenues were $31.0 million for the three months ended March 31, 2016, compared to $33.6 million for the three months ended March 31, 2015, which represents a decrease of $2.6 million, or 8%, in segment revenues as a result of a $2.9 million decrease in natural gas transportation services primarily driven by decreased prices on fuel reimbursements and warmer weather conditions that created less demand for short-term transportation capacity during the three months ended March 31, 2016 compared to the three months ended March 31, 2015.

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Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation & Logistics segment were $20.3 million for the three months ended March 31, 2016 compared to $21.1 million for the three months ended March 31, 2015, which represents a decrease of $0.7 million, or 3%. The overall decrease in operating costs and expenses was primarily driven by a $0.9 million decrease in cost of transportation services due to lower costs associated with fuel reimbursements as a result of decreased prices, a $0.5 million decrease in general and administrative costs due to a reduction in costs allocated to the segment, a $0.4 million decrease in taxes, other than income taxes, due to lower property tax estimates as a result of successful appeals with state taxing authorities on the assessed value of property, which lowered 2015 and 2016 tax accruals beginning in the second quarter of 2015. These decreases were partially offset by a $1.1 million increase in cost of sales due to increased volumes of natural gas sold, partially offset by a 31% decrease in natural gas prices.

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

Segment Financial Data - Processing & Logistics (1)	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Revenues:		
Sales of natural gas, NGLs, and crude oil	$13,578	$21,764
Processing and other revenues	7,623	10,266
Total revenues	21,201	32,030
Operating costs and expenses:		
Cost of sales	12,432	19,519
Cost of transportation services	551	36
Operations and maintenance	2,766	2,420
Depreciation and amortization	3,175	3,301
General and administrative	1,676	1,111
Taxes, other than income taxes	423	106
Loss on sale of assets	—	4,483
Total operating costs and expenses	21,023	30,976
Operating income	$178	$1,054

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 13 – Reporting Segments to the accompanying condensed consolidated financial statements.

Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015

Revenues. Processing & Logistics segment revenues were $21.2 million for the three months ended March 31, 2016, compared to $32.0 million for the three months ended March 31, 2015, which represents a $10.8 million, or 34%, decrease in segment revenues. The decrease in segment revenues was primarily due to a $8.2 million decrease in the sales of natural gas, NGLs, and crude oil driven by lower NGL sales of $7.5 million due to a 27% decrease in NGL prices and lower volumes processed and lower natural gas sales of $0.7 million, a $2.6 million decrease in processing and other revenues driven by lower processing fees at TMID due to decreased volumes processed, and a $2.0 million decrease in fresh water transportation revenue at Water Solutions, partially offset by $1.4 million of salt water disposal revenue from BNN Western, LLC ("Western"), which was acquired on December 16, 2015.

Operating costs and expenses. Operating costs and expenses in the Processing & Logistics segment were $21.0 million for the three months ended March 31, 2016 compared to $31.0 million for the three months ended March 31, 2015, which represents a decrease of $10.0 million, or 32%. The decrease in operating costs and expenses was driven by a decrease of $7.1 million in cost of sales, primarily due to decreased NGL prices and volumes processed as discussed above, and a $4.5 million noncash loss recognized on the sale of compressor assets in 2015. These decreases were partially offset by a $0.6 million increase in general and administrative costs due to increased costs allocated to Water Solutions as a result of increased operating income, and a $0.5 million increase in cost of transportation services due to costs associated with Western.

Liquidity and Capital Resources Overview

Our primary sources of liquidity for the three months ended March 31, 2016 were borrowings under our revolving credit facility, cash generated from operations, and proceeds from the issuance of common units. We expect our sources of liquidity in the future to include:

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

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

Our total liquidity as of March 31, 2016 and December 31, 2015 was as follows:

	March 31, 2016	December 31, 2015
	(in thousands)	
Cash on hand	$2,885	$1,611
Total capacity under the TEP revolving credit facility	1,500,000	1,100,000
Less: Outstanding borrowings under the TEP revolving credit facility	(1,200,000)	(753,000)
Available capacity under the TEP revolving credit facility	300,000	347,000
Total liquidity	$302,885	$348,611

Revolving Credit Facility

Effective January 4, 2016, in connection with the acquisition of an additional 31.3% membership interest in Pony Express, TEP exercised the committed accordion feature to increase the total capacity of the revolving credit facility from $1.1 billion to $1.5 billion. As discussed in "Recent Developments," effective May 6, 2016 we amended the revolving credit facility to increase the total capacity to $1.75 billion.

The revolving credit facility contains various covenants and restrictive provisions that, among other things, limit or restrict our ability (as well as the ability of our restricted subsidiaries) to incur or guarantee additional debt, incur certain liens on assets, dispose of assets, make certain distributions (including distributions from available cash, if a default or event of default under the credit agreement then exists or would result from making such a distribution), change the nature of our business, engage in certain mergers or make certain investments and acquisitions, enter into non-arms-length transactions with affiliates and designate certain subsidiaries as "Unrestricted Subsidiaries." In addition, we are required to maintain a consolidated leverage ratio of not more than 4.75 to 1.00 (which will be increased to 5.25 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and a consolidated interest coverage ratio of not less than 2.50 to 1.00. As of March 31, 2016, we are in compliance with the covenants required under the revolving credit facility.

The unused portion of the revolving credit facility is subject to a commitment fee, which ranges from 0.300% to 0.500%, based on our total leverage ratio. As of March 31, 2016, the weighted average interest rate on outstanding borrowings was 2.20%. During the three months ended March 31, 2016, our weighted average effective interest rate, including the interest on outstanding borrowings, commitment fees, and amortization of deferred financing costs, was 2.48%.

Equity Distribution Agreement

On October 31, 2014, we entered into an equity distribution agreement pursuant to which we may sell from time to time through a group of managers, as our sales agents, common units representing limited partner interests having an aggregate offering price of up to $200 million. On May 13, 2015 the amount was subsequently amended to $100.2 million in order to account for follow-on equity offerings under our S-3 shelf registration statement. Sales of the common units, if any, will be made by means of ordinary brokers' transactions, to or through a market maker or directly on or through an electronic communication network, a "dark pool" or any similar market venue, or as

otherwise agreed by the Partnership and one or more of the managers. We intend to use the net cash proceeds from any sale of the units for general partnership purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.
During the three months ended March 31, 2016, we issued and sold 337,311 common units with a weighted average sales price of $38.17 per unit under our equity distribution agreement for net cash proceeds of approximately $12.6 million (net of approximately $240,000 in commissions and professional service expenses). We used the net cash proceeds for general partnership purposes. At March 31, 2016, approximately $83.1 million in aggregate offering price remained available to be issued and sold under the equity distribution agreement. Subsequent to March 31, 2016, we issued and sold an additional 2,180,681 common units with a weighted average sales price of $37.93 per unit under our equity distribution agreement for net cash proceeds of approximately $81.9 million (net of approximately $830,000 in commissions and professional service expenses). We used the net cash proceeds for general partnership purposes.
Working Capital
Working capital is the amount by which current assets exceed current liabilities. While various other factors may impact our working capital requirements from period to period, our working capital requirements have typically been, and we expect will continue to be, driven by changes in accounts receivable and accounts payable. Factors impacting changes in accounts receivable and accounts payable could include the timing of collections from customers, payments to suppliers, and the level of spending for capital expenditures. Changes in the market prices of energy commodities, primarily NGLs, that we buy and sell in the normal course of business can also impact the timing of changes in accounts receivable and accounts payable.
As of March 31, 2016, we had a working capital deficit of $16.6 million compared to a working capital deficit of $11.7 million at December 31, 2015, which represents a decrease in working capital of $4.9 million. The overall decrease in working capital was primarily attributable to the following:

- an increase in deferred revenue of $7.3 million from deficiency payments collected by Pony Express;
- an increase in accrued taxes of $5.6 million due to higher estimated property taxes for 2016 as a result of the Pony Express lateral in Northeast Colorado placed into service during the second quarter of 2015 and the Western assets acquired in December 2015; and
- a decrease of $4.4 million in accounts receivable, due to a decrease in incremental barrels shipped at Pony Express in March 2016 compared to December 2015.

These working capital decreases were partially offset by:

- a decrease of $4.4 million in accounts payable, primarily driven by the timing of project invoices and payment of contractor retainages related to the construction of the Pony Express lateral in Northeast Colorado;
- a decrease of $3.5 million in accrued liabilities, primarily driven by employee short-term incentive payments during the three months ended March 31, 2016; and
- a decrease of $3.4 million in accounts payable to related parties driven by the payment of balances due to TD as of December 31, 2015 to fund TEP's portion of expansion capital projects 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:

	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$88,757	$48,639
Investing activities	$(66,638)	$(713,611)
Financing activities	$(20,845)	$664,981

Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015

Operating Activities. Cash flows provided by operating activities were $88.8 million and $48.6 million for the three months ended March 31, 2016 and 2015, respectively. The increase in net cash flows provided by operating activities of $40.1 million was primarily driven by the increase in operating results and a net increase in cash inflows from changes in working capital, primarily driven by a $11.5 million increase in net cash inflows from accounts receivable due to decreased receivables at Pony Express during the three months ended March 31, 2016, compared to an increase in receivables at Pony Express during the three months ended March 31, 2015, and a $7.1 million increase in deficiency payments received by Pony Express, partially offset by an $8.7 million increase in net cash outflows from accounts payable and accrued liabilities.

Investing Activities. Cash flows used in investing activities were $66.6 million and $713.6 million for the three months ended March 31, 2016 and 2015, respectively. During the three months ended March 31, 2016, net cash used in investing activities were driven by the $49.1 million cash outflow for a portion of the acquisition of an additional 31.3% membership interest in Pony Express, the remainder of which is classified as a financing activity as discussed below, and capital expenditures of $17.5 million, primarily due to post in-service spending on Pony Express System projects. During the three months ended March 31, 2015, net cash used in investing activities were driven by the $700.0 million cash outflow for the acquisition of an additional 33.3% membership interest in Pony Express and capital expenditures of $13.3 million, primarily due to construction of the Pony Express System.

Financing Activities. Cash flows used in, and provided by, financing activities were $20.8 million and $665.0 million for the three months ended March 31, 2016 and 2015, respectively. Financing cash outflows for the three months ended March 31, 2016 were primarily driven 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; and
- distributions to unitholders of $59.0 million.

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

- net borrowings under the revolving credit facility of $447.0 million;
- the issuance of 337,311 common units under the Equity Distribution Agreement for net cash proceeds of $12.6 million; and
- contributions from noncontrolling interests of $7.2 million, which primarily consisted of contributions from TD to Pony Express.

Cash flows provided by financing activities for the three months ended March 31, 2015 were primarily driven by:

- net cash proceeds of $551.9 million from the issuance of 11.2 million common units in a public offering; and
- net borrowings under the revolving credit facility of $139.0 million.

These financing cash inflows were partially offset by distributions to unitholders of $28.3 million.

Distributions

We do not have a legal obligation to pay distributions except as provided in our partnership agreement. A distribution of $0.705 per unit, or $68.9 million in the aggregate, for the three months ended March 31, 2016 was announced on April 12, 2016 and will be paid on May 13, 2016 to unitholders of record on April 21, 2016. As of May 9, 2016, we had a total of 72,931,602 common and general partner units outstanding, which equates to an aggregate MQD of approximately $21.0 million per quarter and approximately $83.9 million per year. We intend to continue to pay quarterly distributions at or above the amount of the MQD, which is $0.2875 per unit.

Capital Requirements

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

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

or improvements on the capital assets owned, or acquisition or construction of new capital assets).

We expect to incur approximately $36 million for capital expenditures in 2016, of which approximately $24 million is expected for expansion projects and approximately $12 million, net of anticipated reimbursements from affiliates, is expected for maintenance capital expenditures.

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

	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Maintenance capital expenditures	$2,170	$1,511
Expansion capital expenditures	11,731	80,996
Total capital expenditures incurred	$13,901	$82,507

Capital expenditures incurred represent capital expenditures paid and accrued during the period, inclusive of Pony Express capital expenditures paid by TD on behalf of Pony Express and settled via the cash management agreement during periods prior to December 31, 2015. The increase in maintenance capital expenditures to $2.2 million for the three months ended March 31, 2016 from $1.5 million for the three months ended March 31, 2015 is primarily driven by increased maintenance capital expenditures in the Natural Gas Transportation & Logistics segment. Maintenance capital expenditures on our assets occur on a regular schedule, but most major maintenance projects are not required every year so the level of maintenance capital expenditures naturally varies from year to year and from quarter to quarter. The decrease in expansion capital expenditures to $11.7 million for the three months ended March 31, 2016 from $81.0 million for the three months ended March 31, 2015 is primarily driven by spending on the Pony Express System lateral in Northeast Colorado prior to commencement of commercial operations in the second quarter of 2015. Expansion capital expenditures of $11.7 million for the three months ended March 31, 2016 consisted primarily of post in-service spending on Pony Express System projects.

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

Contractual Obligations

There have been no material changes in our contractual obligations as reported in our 2015 Form 10-K.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The critical accounting policies and estimates used in the preparation of our condensed consolidated financial statements are set forth in our 2015 Form 10-K for the year ended December 31, 2015 and have not changed.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

As of March 31, 2016 approximately 92% of our reserved processing capacity was subject to firm or volumetric fee contracts, with the majority of fee revenue based on the volumes actually processed. The remaining 8% was subject to commodity sensitive contracts such as percent of proceeds or keep whole processing contracts. The profitability of our commodity sensitive processing contracts that include keep whole or percent of proceeds components is affected by volatility in prevailing NGL and natural gas prices. We do not currently hedge the commodity exposure in our commodity sensitive contracts in our Processing & Logistics segment and we do not expect to in the foreseeable future. During 2015, NGL and natural gas prices declined substantially and these declines directly and indirectly resulted in lower realizations and processing volumes on our percent of proceeds and keep whole processing contracts. Our Processing & Logistics segment comprised approximately 4% and 17% of our Adjusted EBITDA for the three months ended March 31, 2016 and 2015, respectively.

We have a limited amount of direct commodity price exposure related to crude oil collected as part of our contractual pipeline loss allowance at Pony Express. We do not currently hedge this commodity exposure, but we may enter into hedging agreements in the future. We also have a limited amount of direct commodity price exposure related to natural gas collected related to electrical compression costs and lost and unaccounted for gas on the TIGT System. Historically, we have entered into derivative contracts with third parties for a substantial majority of the gas we expect to collect during the current year for the purpose of hedging our commodity price exposures. As of March 31, 2016, we had natural gas swaps outstanding with a notional volume of approximately 0.4 Bcf short, representing a portion of the natural gas that is expected to be sold by our Natural Gas Transportation & Logistics segment through the end of 2016. The fair value of these swaps was a liability of approximately $44,000 at March 31, 2016.

We measure the risk of price changes in our natural gas swaps utilizing a sensitivity analysis model. The sensitivity analysis measures the potential income or loss (i.e., the change in fair value of the derivative instruments) based upon a hypothetical 10% movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. We enter into derivative contracts solely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore, both the sensitivity analysis model and the change in the market value of our outstanding derivative contracts are offset largely by changes in the value of the underlying physical natural gas sales. A hypothetical 10% increase in the natural gas price forward curve would result in a decrease of approximately $0.1 million in the net fair value of our derivative instruments for the quarter ended March 31, 2016 as a result of our hedging program. For the purpose of determining the change in fair value associated with the hypothetical natural gas price increase scenario, we have assumed a parallel shift in the forward curve through the end of 2016.

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

Interest Rate Risk

As described in "Liquidity and Capital Resources Overview" above, TEP currently has a $1.5 billion revolving credit facility with borrowings of approximately $1.2 billion as of March 31, 2016. Borrowings under the revolving credit facility will bear interest, at our option, at either (a) a base rate, which will be a rate equal to the greatest of (i) the prime rate, (ii) the U.S. federal funds rate plus 0.5% and (iii) a one-month reserve adjusted Eurodollar rate plus 1.00% or (b) a reserve adjusted Eurodollar Rate, plus, in each case, an applicable margin. For loans bearing interest based on the base rate, the applicable margin was initially 1.00%, and for loans bearing interest based on the reserve adjusted Eurodollar rate, the applicable margin was initially 2.00%. After June 25, 2014, the applicable margin ranges from 0.75% to 2.75%, based upon our total leverage ratio and whether we have elected the base rate or the reserve adjusted Eurodollar rate. We do not currently hedge the interest rate risk on our borrowings under the revolving credit facility. However, in the future we may consider hedging the interest rate risk or may consider choosing longer Eurodollar borrowing terms in order to fix all or a portion of our borrowings for a period of time. We estimate that a 1% increase in interest rates would decrease the fair value of the debt by $0.3 million based on our debt obligations as of March 31, 2016.

Credit Risk

We are exposed to credit risk. Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We manage our exposure to credit risk associated with customers to whom we extend credit through a credit approval process which includes credit analysis, the establishment of credit limits and

ongoing monitoring procedures. We may request letters of credit, cash collateral, prepayments, guarantees or bonds as forms of credit support. We have historically experienced only minimal credit losses in connection with our receivables.
A substantial majority of our revenue is produced under long-term firm fee contracts with high-quality customers. The customer base we currently serve under these contracts generally has a strong credit profile, with slightly under 50% of our revenues derived from customers who have an investment grade credit rating or are part of corporate families with investment grade credit ratings as of March 31, 2016. This represents a decrease in the portion of our revenues derived from customers with an investment grade credit rating from previous quarters, primarily as a result of credit downgrades at several of our customers and throughout the industry due to the current commodity price environment.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control over Financial Reporting

During the first quarter of 2016, we completed an upgrade of our general ledger system. This system was used to produce information contained in this Quarterly Report. There have been no other changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended March 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Item 1A of our 2015 Form 10-K for the year ended December 31, 2015 set forth information relating to important risks and uncertainties that could materially adversely affect our business, financial condition or operating results. Those risk factors continue to be relevant to an understanding of our business, financial condition and operating results for the quarter ended March 31, 2016. Other than as set forth below, there have been no material changes to the risk factors contained in our 2015 Form 10-K for the three months ended March 31, 2016.

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 October 2015, PHMSA issued a notice of proposed rule-making to its hazardous liquid pipeline safety regulations. Among other things, the proposed regulations would expand the current leak-detection requirements, apply new, more conservative repair criteria and establish timelines for inspecting pipeline facilities potentially affected by an extreme weather event or natural disaster. The proposal would also increase the stringency of integrity management program requirements and set deadlines for the use of internal inspection tools on certain systems. In addition, on April 8, 2016, PHMSA published a notice of proposed rule-making (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. We are still monitoring and evaluating the effect of these proposed requirements on our operations. 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.

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

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

In connection with our acquisition of the Trailblazer Pipeline, Tallgrass Development agreed to contractually indemnify TEP for any out of pocket costs incurred between April 1, 2014 and April 1, 2017 related to repairing or remediating the Trailblazer Pipeline, to the extent that such actions are necessitated by external corrosion caused by the pipeline's disbonded Hi-Melt CTE coating. The contractual indemnity provided by Tallgrass Development is currently capped at $20 million and is subject to an annual $1.5 million deductible. We will continue pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the U.S. Department of Transportation regulations. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines, which expenditures could be material.

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

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

Further, additional laws, regulations and policies that may be enacted or adopted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. For example, PHMSA issued an Advisory Bulletin in May 2012 which advised pipeline operators that they must have records to document the MAOP for each section of their pipeline and that the records must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing (including hydrotesting) or modifying or replacing facilities to meet the demands of verifiable pressures, could significantly increase our costs. TIGT continues to investigate and, when necessary, report to PHMSA the miles of pipeline for which it has incomplete records for MAOP. We are currently undertaking an extensive internal record review in view of the anticipated PHMSA annual reporting requirements. Additionally, failure to locate such records or verify maximum pressures could require us to operate at reduced pressures, which would reduce available capacity on our natural gas pipeline systems. These specific requirements do not currently apply to crude oil pipelines, but forthcoming regulations implementing the Pipeline Safety Act of 2011 likely will expand the scope of regulation applicable to crude oil pipelines. There can be no assurance as to the amount or timing of future expenditures required to comply with pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. In addition, we may be subject to enforcement actions and penalties for failure to comply with pipeline regulations. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial position, results of operations and prospects. In addition, we may be subject to enforcement actions and penalties for failure to comply with pipeline regulations.

The Partnership may fail to realize the growth anticipated as a result of the REX Acquisition.

As discussed in Item 5.—Other Information, the Partnership has consummated the acquisition of a 25% membership interest in REX and such consummation involves potential risks, including, without limitation, the failure to realize expected profitability, growth or accretion; the incurrence of liabilities or other compliance costs related to environmental, pipeline safety or regulatory matters, including potential liabilities that may be imposed without regard to fault or the legality of conduct; and the incurrence of unanticipated liabilities and costs for which indemnification is unavailable or inadequate. For example, on April 8, 2016, the Pipeline and Hazardous Materials Safety Administration published a notice of proposed rulemaking that would revise safety requirements for natural gas transmission and gathering lines. Though this is still a notice of proposed rulemaking, if it were to become final, this rule and others like it could result in significant costs. If these risks or other unanticipated liabilities were to materialize, any desired benefits of the acquisition of the membership interest in REX may not be fully realized, if at all, and the Partnership's future financial performance and results of operations could be negatively impacted.

A significant amount of REX's revenue in 2015 was derived under long-term firm fee contracts for west-to-east service expiring in 2019, and it is expected that a significant amount of REX's revenue in 2016 will be derived under these contracts. REX may not be able to renew or replace expiring contracts at favorable rates or on a long-term basis. If REX is not able to renew or replace its expiring customer contracts at favorable rates or on a long-term basis, the Partnership's financial condition, results of operations, cash flows and ability to make cash distributions to its unitholders will be adversely affected.

A majority of REX's west-to-east pipeline capacity is subject to long-term firm fee contracts that expire at various dates in 2019 and a significant amount of REX's revenue in 2015 was derived under these contracts. The Partnership expects a significant amount of REX's revenue in 2016 to be derived under these contracts despite the completion of the Zone 3 East-to-West Project that was placed into commercial service on August 1, 2015.

If an existing REX shipper terminates or breaches its long-term firm contract or elects to not renew its contract at the end of its term, REX may be subject to a loss of revenue if REX is unable to promptly resell the capacity to another shipper on substantially equivalent terms. REX's ability to enter into a long-term firm fee contract with another shipper on substantially equivalent terms and conditions is uncertain and depends on a number of factors beyond the Partnership's control, including:

- the timing, volume and location of new market demands;
- competition from alternative sources of natural gas and other fuels;
- differences in the supply and price of natural gas in the Rocky Mountain region and supply basins outside the Rocky Mountain region, including the Marcellus and Utica shales;
- the demand for natural gas in markets served by REX;
- the effects of federal and state regulation on customer contracting practices; and

•the availability and competitiveness of alternative gas transportation services in the markets REX serves.

The rapid increase in the production of natural gas over the past several years from the Marcellus and Utica shale formations, among other supply basins, has resulted in a decreased demand for the transportation of Rocky Mountain gas to the Northeast. In addition, this increase has resulted in a market price for natural gas in the Marcellus and Utica shale formations that is lower relative to NYMEX Henry Hub. A continuation of this trend will make it difficult for REX to replace its existing long-term firm fee contracts for shipments from west-to-east on terms and with pricing similar to that contained in REX's existing contracts to ship gas from west-to-east.

The Partnership cannot assure you that REX will be able to negotiate replacements of its existing contracts on terms and conditions, including pricing, that are as favorable to REX as its existing contracts. If REX is unable to extend its current transportation contracts when they expire or replace them with new contracts that have terms as favorable as the existing contracts, the Partnership could suffer a material reduction in its revenues, earnings and cash flows and its ability to make cash distributions to its unitholders may be materially impaired.

REX is exposed to the creditworthiness and performance of its customers, suppliers and contract counterparties, and any material nonpayment or nonperformance by one or more of these parties could adversely affect the Partnership's financial condition, cash flows, and operating results.

Although REX attempts to assess the creditworthiness of its customers, suppliers and contract counterparties, there can be no assurance that its 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 the Partnership's business, results of operations, financial condition and ability to make cash distributions to its unitholders. REX's long-term firm fee contracts obligate its customers to pay reservation charges regardless of whether they utilize REX's assets, except for certain circumstances outlined in applicable customer agreements. As a result, during the term of REX's long-term firm fee contracts, and absent an event of force majeure, REX's revenues will generally depend on its customers' financial condition and their ability to pay rather than upon the amount of natural gas transported. The recent decline in natural gas prices has negatively impacted the financial condition of some of REX's customers and further declines, sustained lower prices, or continued volatility could impact their ability to meet their financial obligations to REX. Further, REX's contract counterparties may not perform or adhere to REX's existing or future contractual arrangements. To the extent one or more of REX's 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 or other bankruptcy and insolvency laws. Any material nonpayment or nonperformance by REX's contract counterparties due to inability or unwillingness to perform or adhere to contractual arrangements, whether due to a filing under the United States Bankruptcy Code or otherwise, could have a material adverse impact on REX's business, results of operations, financial condition and ability to make distributions to its members.

For example, in early 2016, Ultra Resources, Inc., or Ultra, defaulted on its firm transportation service agreement for approximately 0.2 Bcf/d through November 11, 2019. Approximately 13% of REX's revenue in 2015 was derived from the Ultra contract. In late March 2016, REX terminated Ultra's service agreement. As of April 4, 2016, in addition to other amounts owed under law or equity, REX has asserted that Ultra owes approximately $303 million for past transportation service charges and for reservation charge fees that REX would have received over the term of the service agreement had Ultra not defaulted. In a Form 10-K filed with the SEC by Ultra Petroleum Corp., Ultra's parent, on February 29, 2016, significant liquidity and capital structure issues were outlined that suggested Ultra might pursue a filing under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act. Ultra Petroleum Corp. announced on April 1, 2016 that it was deferring a $26 million interest payment to its noteholders, starting a 30 day grace period to make the interest payment. REX intends to pursue all available legal remedies to maximize its recovery, and on April 14, 2016 REX filed a lawsuit against Ultra for breach of contract and damages in Harris County, Texas, in which REX seeks approximately $303 million in damages and other relief. REX currently believes it may be unlikely that it will be able to collect all of the amounts it seeks from Ultra and it is uncertain how much, if any, REX will ultimately be able to recover. In particular, Ultra, together with its parent and other affiliates, filed voluntary petitions for relief pursuant to Chapter 11 of the United States Bankruptcy Code on April 30, 2016. Such filing by Ultra will likely further limit REX's ability to recover damages. Further, it is also

unlikely that REX will be able to remarket the capacity that was subject to the service agreement at the rate stated in the now-terminated Ultra service agreement and, as a result, REX may be unable to remarket the capacity at all for a term longer than one year due to the most favored nations rights in the Partnership's other original long term transportation contracts described in the risk factor below.
In addition, Triad Hunter, LLC, or Triad, together with certain of its affiliates, filed voluntary petitions for relief pursuant to Chapter 11 of the United States Bankruptcy Code in December 2015, which the Partnership refers to as the Chapter 11 Cases. Triad and REX are parties to a precedent agreement that will provide Triad with an approximate 0.1 Bcf/d of firm capacity in connection with the REX Zone 3 Capacity Enhancement Project, subject to certain terms and conditions of service. Upon the commencement of the Chapter 11 Cases, REX and Triad entered into negotiations to amend certain terms of the precedent agreement. These negotiations resulted in an agreement in principle to amend certain material terms of the precedent agreement, exclusive of the rate or term. On April 18, 2016, the Bankruptcy Court conducted a hearing to consider the plan of

reorganization submitted by Triad and its debtor affiliates, which included the as-amended precedent agreement with REX. During the hearing, Triad stated on the record that it had reached agreement with REX on an amended precedent agreement and that it intended to assume the same. Following the hearing, the Bankruptcy Court entered an order on April 18, 2016 confirming the plan of reorganization. The amended precedent agreement became effective and binding on REX and Triad immediately upon the entry of the Bankruptcy Court's order confirming the plan.

The procedures and policies REX uses to manage its 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 REX's own internal credit policies, counterparties with investment grade credit ratings are deemed able to meet their financial obligations to REX without requiring credit support in the form of a letter of credit or prepayment. With the recent decline in natural gas prices and the corresponding deterioration of the financial condition of some of REX's customers, it is possible that some may lose their investment grade credit rating. If this were to occur, REX would likely ask for credit support and the customer may be unwilling or unable to provide it due to liquidity constraints. To the extent REX's procedures and policies prove to be inadequate or REX is unable to obtain credit support, the Partnership's financial position and results of operations may be negatively impacted.

Some of REX's counterparties may be highly leveraged or have limited financial resources and are subject to their own operating and regulatory risks. Even if REX's credit review and analysis mechanisms work properly, REX may experience financial losses in its dealings with such parties. As seen with the recent decline in natural gas prices, prices for 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 REX's control. Such volatility in commodity prices might have an impact on many of REX's 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 REX and may also increase the magnitude of these obligations.

Certain projects may also be subject to the financial risks of key suppliers and contractors. For example, REX has a critical engineering, procurement and construction contract with QPS Engineering, LLC with respect to the REX Zone 3 Capacity Enhancement Project, and would be harmed financially in the event QPS Engineering, LLC were to enter bankruptcy or receivership, or experience other financial difficulty.

Any material nonpayment or nonperformance by REX's counterparties could require REX to pursue substitute counterparties for the affected operations, renegotiate contract terms, 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.

REX depends on certain key customers for a significant portion of its revenues and is exposed to credit risks of these customers. The loss of or material nonpayment or nonperformance by any of these key customers could adversely affect the Partnership's cash flow and results of operations.

REX relies on certain key customers for a portion of its revenues. For example, for the year ended December 31, 2015, REX's three largest non-affiliated shippers accounted for approximately 24%, 21%, and 13%, respectively, of REX's total revenues.

REX may be unable to negotiate extensions or replacements of contracts with key customers on favorable terms. In addition, some of these key customers may experience financial problems that could have a significant effect on their creditworthiness. For example, REX terminated its contract with its third largest non-affiliated shipper by total revenue, Ultra, in March 2016 and subsequently, Ultra filed a voluntary petition for relief pursuant to Chapter 11 of the United States Bankruptcy Code on April 30, 2016. See "-REX is exposed to the creditworthiness and performance of its customers, suppliers and contract counterparties, and any material nonpayment or nonperformance by one or more of these parties could adversely affect the Partnership's financial condition, cash flows, and operating results." Severe financial problems encountered by REX's customers could limit REX's ability to collect amounts owed to it, or to enforce performance of obligations under contractual arrangements. To the extent one or more of REX's key customers is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation, rejection or assignment to unknown third parties under applicable provisions of the United States Bankruptcy Code. Additionally, many of REX's customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of REX's customers' liquidity and limit their ability to make payments or perform on their obligations to the Partnership. Furthermore, some of REX's 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 REX. 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 the Partnership's business, cash flows, ability to make distributions to its unitholders, the price of its units, its results of operations and ability to conduct its business.

Most of REX's revenues are from long-term negotiated rate contracts for west-to-east service that contain most favored nations rate provisions, limiting its flexibility to offer any available or expiring west-to-east long-term capacity to new shippers on the REX Pipeline System at less than the rates of long-term negotiated rate shippers without substantial financial impacts to REX's revenues.

REX's foundation and anchor shippers for west-to-east service hold certain most favored nations rights, or MFNs, granting them a right to a rate reduction in certain limited instances where REX 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 REX's 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 REX charges, which could have a material adverse effect on REX's revenues, cash flow and results of operations.

REX has a substantial amount of debt.

As of May 6, 2016 REX had approximately $2.575 billion of total indebtedness outstanding.

The scheduled maturities of REX outstanding debt balances as of December 31, 2015 are summarized as follows (in millions):

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

In addition, REX has a revolving credit facility, which will mature on January 31, 2020, with approximately $150 million of additional borrowing capacity available as of May 6, 2016.

The substantial debt held by REX could have important consequences. For example, it could:

- make it more difficult for REX to satisfy its obligations with respect to its debt;
- increase the vulnerability of REX to general adverse economic and industry conditions;
- limit the ability of REX to obtain additional financing for future working capital, capital expenditures and other general corporate purposes;
- require REX to dedicate a substantial portion of its cash flow from operations to payments on its debt, 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 REX operates;
- place REX at a competitive disadvantage compared to its competitors that have less debt; and
- have a material adverse effect if REX fails to comply with the covenants in the indenture relating to its notes or in the instruments governing its other debt.

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

REX's debt instruments may limit its financial flexibility and increase its financing costs.

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

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

The instruments governing any future debt may contain similar or more restrictive provisions. REX's ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be restricted.

REX may not be able to generate a sufficient amount of cash flow to meet its debt service obligations.

REX's ability to make scheduled payments or to refinance its obligations with respect to its debt 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 REX's revenue is generated by long term contracts that expire in 2019 and REX 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. If REX's 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 debt. The payment of additional capital contributions by the Partnership to REX to fund such obligations would reduce the Partnership's amount of cash available to pay distributions to its common unitholders.

The Partnership cannot assure you that REX's operating performance, cash flow and capital resources will be sufficient for payment of its debt in the future. In the event that REX is required to dispose of material assets or restructure its debt to meet its debt service and other obligations, the Partnership cannot assure you as to the terms of any such transaction or how soon any such transaction could be completed.

Constructing new assets subjects REX to risks of project delays, cost overruns, potential litigation and lower-than-anticipated volumes of natural gas once a project is completed. Operating cash flows from REX's capital projects may not be immediate or meet its expectations.

One of the ways REX may grow its business is by constructing additions or modifications to its existing facilities. For example, REX is currently undertaking the REX Zone 3 Capacity Enhancement Project, a large scale construction project on the REX Pipeline System that, when complete, will add three (3) new compressor stations, modify two (2) existing compression stations and construct certain ancillary facilities. The proposed facilities are expected to increase the Zone 3 east-to-west mainline delivery capacity on the REX Pipeline System by approximately 0.8 Bcf/d from receipts at Clarington, Ohio to corresponding deliveries of approximately 0.52 Bcf/d and approximately 0.28 Bcf/d to Lebanon, Ohio and Moultrie County, Illinois, respectively. It is currently expected to be placed in service sometime during December 2016 and has a reported total cost of approximately $532 million, with approximately $285 million expected to be spent from April 1, 2016 through April 2017. Completion of construction projects such as the REX Zone 3 Capacity Enhancement Project require significant amounts of capital and involve numerous regulatory, environmental, pipeline safety, political, legal and operational uncertainties, many of which are beyond REX's control. These projects also involve numerous economic uncertainties, including the impact of inflation on project costs and the availability of required resources, and are often subject to cost overruns, delays in completion and potential litigation claims. For example, on June 17, 2014, Michels Corporation, or Michels, filed a complaint and request for relief against REX as a result of work performed by Michels to construct the Seneca Lateral Pipeline in Ohio. Michels seeks unspecified damages from REX and asserts claims of breach of contract, negligent misrepresentation, unjust enrichment and quantum meruit, and has also filed notices of Mechanic's Liens in Monroe and Noble Counties, asserting $24.2 million as the amount due. REX believes Michels' claims are without merit and plans to continue to vigorously contest all of the claims in this matter, but the outcome and impact of these legal proceedings cannot be predicted with certainty.

REX may be unable to complete announced construction projects such as the REX Zone 3 Capacity Enhancement Project on schedule, at the budgeted cost, or at all, which could have a material adverse effect on REX's business and results of operations. For example, certain of REX's customers will have the right to terminate their contracts with REX in the event that the additional capacity of the REX Zone 3 Capacity Enhancement Project has not been made available to those customers by June 30, 2017. Moreover, REX may not receive any material increase in its operating cash flow from any such projects for some time. For instance, with respect to the REX Zone 3 Capacity Enhancement Project, substantially all of the construction expenditures are expected to have occurred during 2015 and 2016, yet REX will not receive any material increases in cash flow until the project is completed and fully operational, which is currently expected to be during December 2016. In addition, REX's cash flow from a project like the REX Zone 3

Capacity Enhancement Project may be delayed or may not meet its expectations. REX's 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.

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

The Partnership's investment in REX is a minority interest and could be adversely affected by its lack of sole decision-making authority and its reliance on the financial condition of the other members.

Entering into REX as a minority-interest partner, the Partnership would not control REX's strategies and operations. Thus, the Partnership's investment in REX involves risks that are not present when the Partnership is able to exercise control over an asset, including the possibility that the other members of REX might become bankrupt, fail to fund their required capital contributions or otherwise make business decisions with respect to REX that the Partnership does not believe is in its best interest. The other members of REX, including TD, may have economic or other business interests or goals that are inconsistent with the Partnership's business interests or goals, and may be in a position to take actions contrary to the Partnership's policies or objectives. The REX limited liability company agreement expressly permits REX members to make decisions with respect to their ownership interest without taking into account the interests of REX or any other member of REX. Moreover, under the REX limited liability company agreement, the Partnership will be required to provide certain capital contributions in order to fund expenditures contemplated by REX's annual budget, and may be required to provide capital contributions under certain circumstances specified in the REX limited liability company agreement if determined to be reasonably necessary by a vote of REX's members. Under the limited liability company agreement of REX, 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. Further, TEP will not be the operator of REX, and the Partnership may disagree with the proposals of the operator of REX from time to time.

The Partnership's membership interest in REX will be subject to a right of first refusal, which may make it more difficult to sell its interest in REX in the future.

Under the terms of REX's 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 the Partnership desires to sell all or any portion of its interest in REX in the future, the Partnership will be required to first offer the sale of its 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 the Partnership to sell its interest in REX.

TEP and TD will control a significant percentage of REX's voting power but will vote independently of each other.

TEP and TD will collectively hold 75% of the voting power of REX. Although TEP and TD may act together to exercise their combined voting power under the terms of the REX LLC Agreement, TD will be entitled to act separately and in its own interest with respect to its membership interest in REX and the Partnership does not currently expect to have a voting trust or other arrangement in place requiring the Partnership or TD to vote jointly. REX's daily operations are managed by TD. Under the limited liability company agreement of REX, 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. Pursuant to the REX limited liability company agreement, REX is required to distribute all of its unrestricted cash and cash equivalents to its members on a quarterly basis, less any portion set aside to maintain reasonably adequate reserves for REX's operations, as well as to make certain distributions to its members for reimbursement of development costs incurred in connection with the construction and ownership of the REX Pipeline System. Pursuant to the REX limited liability company agreement, REX's members are required to provide capital contributions on a quarterly basis to fund expenditures contemplated by REX's annual budget, as well as under certain other circumstances specified in the REX limited liability company agreement if determined to be reasonably necessary by REX's board of directors.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

As previously discussed in Item 2.—Management's Discussion and Analysis of Financial Condition and Results of Operations, TD offered the Partnership the right to assume the rights and obligations of REX Holdings under the Purchase Agreement, including the right to acquire a 25% membership interest in REX. REX is a Delaware limited liability company engaged in the ownership and operation of the Rockies Express Pipeline, an approximately 1,712-mile natural gas pipeline transportation system regulated by the FERC, traversing an area from the Rocky Mountain Region to the Appalachian Mountain Region.

On May 6, 2016, TEP REX and REX Holdings entered into an Assignment and Assumption Agreement (the "Assumption Agreement") pursuant to which REX Holdings assigned to TEP REX all of its rights under the Purchase Agreement and, in exchange, TEP REX assumed all of the rights and obligations of REX Holdings under the Purchase Agreement. The Assumption Agreement contains representations and warranties, indemnification obligations and covenants by the parties, and a copy of the Assumption Agreement will be filed by the Partnership in a subsequent report. TD was also party to the Assumption Agreement for the sole purpose of making certain representations, warranties and covenants and giving certain indemnities as the sole owner of REX Holdings.

Subsequently on May 6, 2016, TEP REX closed the purchase of a 25% membership interest in REX from Sempra pursuant to the Purchase Agreement for cash consideration of approximately $436 million, after making the adjustments to the purchase price required by the Purchase Agreement (the "REX Acquisition"). A copy of the Purchase Agreement will be filed by the Partnership in a subsequent report. Audited financial statements of REX and unaudited pro forma condensed consolidated financial statements of the Partnership were included in the Partnership's Current Report on Form 8-K filed with the SEC on April 28, 2016.

As part of the REX Acquisition, TEP REX became a member of REX and is a party to the Second Amended and Restated Limited Liability Company Agreement of REX (as amended, including by Amendment No. 2 (the "Amendment") entered into immediately prior to the completion of the REX Acquisition) (the "LLC Agreement"). Under the terms of the LLC Agreement, the Partnership has the right to designate an individual to the Board of Directors of REX, and a vote of directors representing 80% of the membership interests is required for action on substantially all matters. The LLC Agreement also contains transfer restrictions and capital contribution requirements. Copies of the LLC Agreement and the Amendment will be filed by the Partnership in a subsequent report.

In connection with the closing of the Purchase Agreement, on May 6, 2016, the Partnership satisfied certain conditions to increase the total revolving credit commitments from $1.5 billion to $1.75 billion under its existing Credit Agreement dated as of May 17, 2013 with Barclays Bank PLC, as administrative agent, and a syndicate of lenders, (as amended by that certain Amendment No. 4, which was filed on April 28, 2016 in the Partnership's Current Report on Form 8-K, and as otherwise amended, modified, supplemented or waived to the date hereof).

The Conflicts Committee of the Board of Directors of the Partnership's general partner recommended approval of the Assumption to the Board of Directors of the general partner, which then approved the Assumption. The Conflicts Committee, which is composed entirely of independent directors, retained independent legal and financial advisors to assist in evaluating and negotiating the Assumption.

The Assumption Agreement and the Purchase Agreement contain representations and warranties, indemnification obligations and covenants by the parties, which were made only for purposes of those agreements and as of specific dates; were solely for the benefit of the parties to the Assumption Agreement or the Purchase Agreement, as applicable; may be subject to limitations agreed upon by the parties, including being qualified by confidential disclosures made by each contracting party to the other as a way of allocating contractual risk between them that differ from those applicable to investors. Investors should be aware that these representations, warranties and covenants or any description thereof alone may not describe the actual state of affairs of the Partnership, TD or their respective subsidiaries, affiliates, businesses or equity holders as of the date they were made or at any other time. The above descriptions do not purport to be complete descriptions of the Assumption Agreement and the Purchase Agreement and are qualified in their entirety by the contents of the Assumption Agreement and the Purchase Agreement, as applicable, copies of which will be filed in a subsequent report.

Item 6. Exhibits

Exhibit No.	Description
10.1	Contribution and Transfer Agreement, dated January 1, 2016, by and among Tallgrass Energy Partners, LP, Tallgrass Operations, LLC, and for certain limited purposes, Tallgrass Development, LP (incorporated by reference to Exhibit 10.14 to the Partnership's Annual Report on Form 10-K filed on February 17, 2016).
10.2	Amendment No. 4 to Credit Agreement, dated as of April 27, 2016, by and among Tallgrass Energy Partners, LP, Barclays Bank PLC, as administrative agent, and a syndicate of lenders named therein (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on April 28, 2016.
12.1*	Computation of Ratio of Earnings to Fixed Charges
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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		Tallgrass Energy Partners, LP (registrant)			
		By:	Tallgrass MLP GP, LLC, its general partner		
Date:	May 9, 2016	By:	/s/ Gary J. Brauchle		
			Name:	Gary J. Brauchle	
			Title:	Executive Vice President and Chief Financial Officer	

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