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

FORM 10-K

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

For the fiscal year ended December 31, 2017

OR

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

Commission file number 1-31219

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**73-1493906**
(state or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

8111 Westchester Drive, Suite 600, Dallas, Texas 75225
(Address of principal executive offices) (zip code)
Registrant's telephone number, including area code: **(214) 981-0700**

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

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

Securities registered pursuant to section 12(g) of the Act: **None**

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

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

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

The aggregate market value as of June 30, 2017, of the registrant's Common Units held by non-affiliates of the registrant, based on the reported closing price of such Common Units on the New York Stock Exchange on such date, was $21.66 billion. Common Units held by each executive officer and director and by each person who owns 5% or more of the outstanding Common Units have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

At February 16, 2018, the registrant had 1,164,024,480 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (the "Partnership," or "ETP") in periodic press releases and some oral statements of the Partnership's officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as "anticipate," "believe," "intend," "project," "plan," "expect," "continue," "estimate," "goal," "forecast," "may," "will" or similar expressions help identify forward-looking statements. Although the Partnership and its General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership's actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management's control. For additional discussion of risks, uncertainties and assumptions, see "Item 1A. Risk Factors" included in this annual report.

Definitions

The following is a list of certain acronyms and terms generally used in the energy industry and throughout this document:

/d	per day
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
Aqua – PVR	Aqua – PVR Water Services, LLC
AROs	asset retirement obligations
Bbls	barrels
BBtu	billion British thermal units
Bcf	billion cubic feet
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
CDM	CDM Resource Management LLC
CDM E&T	CDM Environmental & Technical Services LLC
Citrus	Citrus, LLC
CrossCountry	CrossCountry Energy, LLC
Dakota Access	Dakota Access, LLC
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
ELG	Edwards Lime Gathering LLC
EPA	United States Environmental Protection Agency
ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC MEP	ETC Midcontinent Express Pipeline, L.L.C.

ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETC Tiger	ETC Tiger Pipeline, LLC
ETCO	Energy Transfer Crude Oil Company, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC for the periods presented herein
ETE Holdings	ETE Common Holdings, LLC, a wholly-owned subsidiary of ETE
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP Holdco	ETP Holdco Corporation
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
Exchange Act	Securities Exchange Act of 1934
ExxonMobil	Exxon Mobil Corporation
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
Gulf States	Gulf States Transmission LLC
HPC	RIGS Haynesville Partnership Co. and its wholly-owned subsidiary, Regency Intrastate Gas LP
IDRs	incentive distribution rights
KMI	Kinder Morgan Inc.
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC), a subsidiary of ETE
LCL	Lake Charles LNG Export Company, LLC
Legacy ETP Preferred Units	legacy ETP Series A cumulative convertible preferred units
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Lone Star	Lone Star NGL LLC
LPG	liquefied petroleum gas
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
Mi Vida JV	Mi Vida JV LLC
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
ORS	Ohio River System LLC
OSHA	federal Occupational Safety and Health Act

OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCBs	polychlorinated biphenyls
PennTex	PennTex Midstream Partners, LP
PEP	Permian Express Partners LLC
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
Phillips 66	Phillips 66 Partners LP
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings, LLC, a subsidiary of ETP
RIGS	Regency Intrastate Gas System
Rover	Rover Pipeline LLC, a subsidiary of ETP
Sea Robin	Sea Robin Pipeline Company, LLC, a subsidiary of Panhandle
SEC	Securities and Exchange Commission
Series A Preferred Units	Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series B Preferred Units	Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Shell	Royal Dutch Shell
Southwest Gas	Pan Gas Storage, LLC
Sunoco GP	Sunoco GP LLC, the general partner of Sunoco LP
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco LP	Sunoco LP (previously named Susser Petroleum Partners, LP)
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
Susser	Susser Holdings Corporation
Transwestern	Transwestern Pipeline Company, LLC
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle
USAC	USA Compression Partners, LP
USAC Holdings	USA Compression Holdings, LLC

Adjusted EBITDA is a term used throughout this document, which we define as earnings before interest, taxes, depreciation, depletion, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Adjusted EBITDA reflects amounts for less than wholly-owned subsidiaries based on 100% of the subsidiaries' results of operations and for unconsolidated affiliates based on the Partnership's proportionate ownership.

PART I

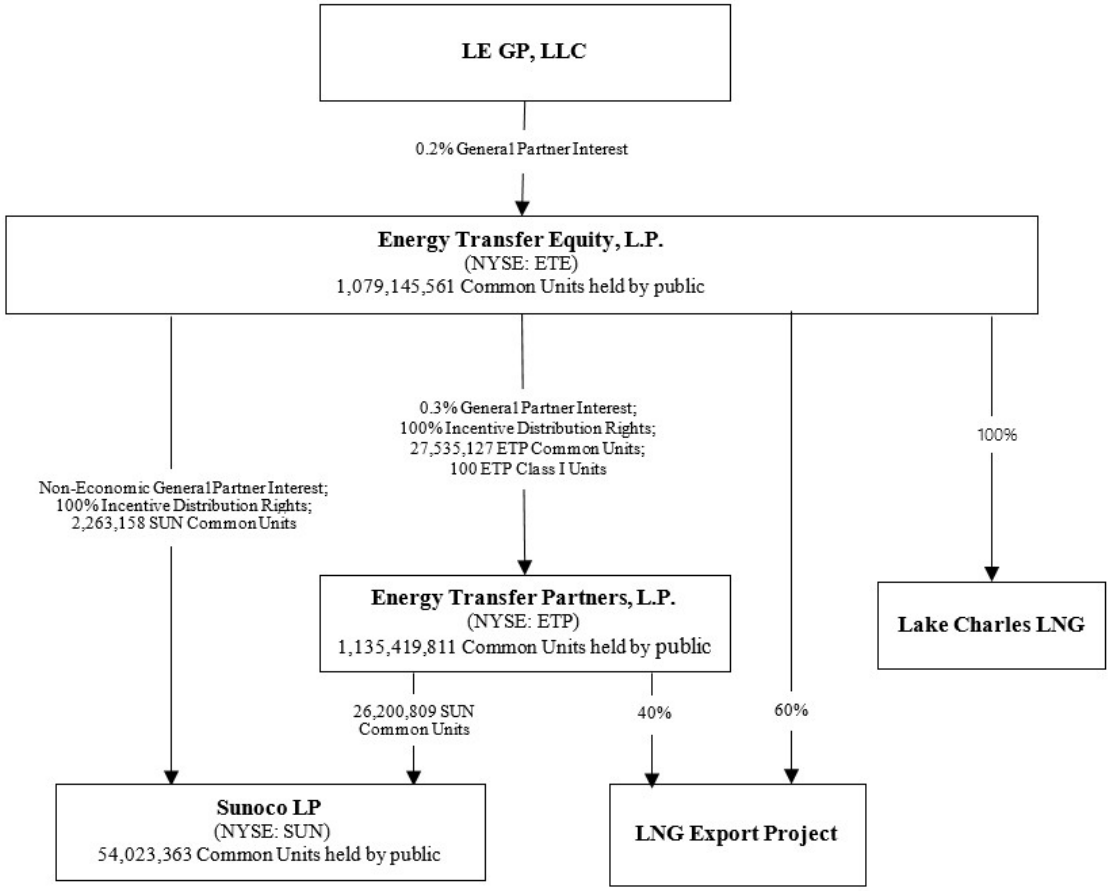
ITEM 1. BUSINESS

Overview

We (Energy Transfer Partners, L.P., a Delaware limited partnership, "ETP" or the "Partnership") are one of the largest publicly traded master limited partnerships in the United States in terms of equity market capitalization (approximately $23.31 billion as of January 31, 2018). We are managed by our general partner, Energy Transfer Partners GP, L.P. (our "General Partner" or "ETP GP"), and ETP GP is managed by its general partner, Energy Transfer Partners, L.L.C. ("ETP LLC"), which is owned by Energy Transfer Equity, L.P., another publicly traded master limited partnership ("ETE"). The primary activities in which we are engaged, all of which are in the United States, and the operating subsidiaries (collectively referred to as the "Operating Companies") through which we conduct those activities are as follows:

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage; and
  - interstate natural gas transportation and storage.
- Crude oil, NGLs and refined product transportation, terminalling services and acquisition and marketing activities, as well as NGL storage and fractionation services.

The following chart summarizes our organizational structure as of February 7, 2018. For simplicity, certain immaterial entities and ownership interest have not been depicted.



Unless the context requires otherwise, the Partnership, the Operating Companies, and their subsidiaries are collectively referred to in this report as "we," "us," "ETP," "Energy Transfer" or "the Partnership."

Significant Achievements in 2017 and Beyond

Strategic Transactions

Our significant strategic transactions in 2017 and beyond included the following, as discussed in more detail herein:

- In February 2017, Bakken Holdings Company LLC, an entity in which ETP indirectly owns a 100% membership interest, sold a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by MPLX LP and Enbridge Energy Partners, L.P., for $2.00 billion in cash. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access and ETCO. The remaining 25% of each of Dakota Access and ETCO is owned by wholly-owned subsidiaries of Phillips 66. As discussed below, in July 2017, the Partnership contributed a portion of its ownership interest in Dakota Access and ETCO to PEP. ETP continues to consolidate Dakota Access and ETCO subsequent to this transaction.
- In February 2017, Sunoco Logistics formed PEP, a strategic joint venture with ExxonMobil. Sunoco Logistics contributed its Permian Express 1, Permian Express 2, Permian Longview and Louisiana Access pipelines. ExxonMobil contributed its Longview to Louisiana and Pegasus pipelines, Hawkins gathering system, an idle pipeline in southern Oklahoma, and its Patoka, Illinois terminal. Assets contributed to PEP by ExxonMobil were reflected at fair value on the Partnership's consolidated balance sheet at the date of the contribution, including $547 million of intangible assets and $435 million of property, plant and equipment.
- In April 2017, Energy Transfer Partners, L.P. and Sunoco Logistics completed a merger transaction (the "Sunoco Logistics Merger") in which Sunoco Logistics acquired Energy Transfer Partners, L.P. in a unit-for-unit transaction, with the Energy Transfer Partners, L.P. unitholders receiving 1.5 common units of Sunoco Logistics for each Energy Transfer Partners, L.P. common unit they owned. In connection with the merger, Sunoco Logistics was renamed Energy Transfer Partners, L.P. and Sunoco Logistics' general partner was merged with and into ETP GP, with ETP GP surviving as an indirect wholly-owned subsidiary of ETE.
- In July 2017, ETP contributed an approximate 15% ownership interest in Dakota Access and ETCO to PEP, which resulted in an increase in ETP's ownership interest in PEP to approximately 88%. ETP maintains a controlling financial and voting interest in PEP and is the operator of all of the assets. As such, PEP is reflected as a consolidated subsidiary of the Partnership. ExxonMobil's interest in PEP is reflected as noncontrolling interest in the consolidated balance sheets. ExxonMobil's contribution resulted in an increase of $988 million in noncontrolling interest, which is reflected in "Capital contributions from noncontrolling interest" in the consolidated statement of equity.
- In October 2017, ETP completed the previously announced contribution transaction with a fund managed by Blackstone Energy Partners and Blackstone Capital Partners, pursuant to which ETP exchanged a 49.9% interest in the holding company that owns 65% of the Rover pipeline ("Rover Holdco"). As a result, Rover Holdco is now owned 50.1% by ETP and 49.9% by Blackstone. Upon closing, Blackstone contributed funds to reimburse ETP for its pro rata share of the Rover construction costs incurred by ETP through the closing date, along with the payment of additional amounts subject to certain adjustments.
- In January 2018, ETP entered into a contribution agreement ("CDM Contribution Agreement") with ETP GP, ETC Compression, LLC, USAC and ETE, pursuant to which ETP will contribute to USAC 100% of the membership interests of CDM and CDM E&T for aggregate consideration of $1.7 billion, consisting of USAC common units, new USAC Class B units and cash. The Class B units will be substantially similar to USAC common units, except the Class B units will not receive distributions paid with respect to USAC common units prior to the one year anniversary of the closing date of the CDM Contribution Agreement. Each Class B Unit will convert into one USAC common unit on such one year anniversary. In connection with the foregoing, ETP entered into a purchase agreement with ETE, ETP LLC, USAC Holdings and, for certain limited purposes, R/C IV USACP Holdings, L.P., pursuant to which ETE and ETP LLC will acquire from USAC Holdings (i) all of the outstanding interests in the general partner of USAC and (ii) 12,466,912 USAC common units for $250 million in cash. The transactions are expected to close in the first half of 2018, subject to customary closing conditions.

Significant Organic Growth Projects

Our significant announced organic growth projects in 2017 included the following, as discussed in more detail herein:

- In June 2017, ETP announced that the Dakota Access Pipeline and the Energy Transfer Crude Oil Pipeline (collectively, the "Bakken Pipeline") were placed in commercial service.
- ETP announced that Phase 1A and Phase 1B of the Rover pipeline were placed in service in August 2017 and December 2017, respectively.

Segment Overview

See Note 15 to our consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" for additional financial information about our segments.

Intrastate Transportation and Storage Segment

Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users, storage facilities, utilities and other pipelines. Through our intrastate transportation and storage segment, we own and operate approximately 7,900 miles of natural gas transportation pipelines with approximately 15.2 Bcf/d of transportation capacity and three natural gas storage facilities located in the state of Texas. We also own a 49.99% general partner interest in RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets. We own a 16% membership interest in the Trans-Pecos and Comanche Trail pipelines, a 338-mile intrastate pipeline system that delivers natural gas from the Waha Hub near Midland, Texas to the United States/Mexico border.

Through ETC OLP, we own the largest intrastate pipeline system in the United States with interconnects to Texas markets and to major consumption areas throughout the United States. Our intrastate transportation and storage segment focuses on the transportation of natural gas to major markets from various prolific natural gas producing areas through connections with other pipeline systems as well as through our Oasis pipeline, our East Texas pipeline, our natural gas pipeline and storage assets that are referred to as the ET Fuel System, and our HPL System, which are described below.

Our intrastate transportation and storage segment's results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly.

We also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and marketing companies on our HPL System. Generally, we purchase natural gas from either the market (including purchases from our marketing operations) or from producers at the wellhead. To the extent the natural gas comes from producers, it is primarily purchased at a discount to a specified market price and typically resold to customers based on an index price. In addition, our intrastate transportation and storage segment generates revenues from fees charged for storing customers' working natural gas in our storage facilities and from managing natural gas for our own account.

Interstate Transportation and Storage Segment

Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users, storage facilities, utilities and other pipelines. Through our interstate transportation and storage segment, we directly own and operate approximately 11,800 miles of interstate natural gas pipelines with approximately 10.3 Bcf/d of transportation capacity and have a 50% interest in the joint venture that owns the 185-mile Fayetteville Express pipeline and the 500-mile Midcontinent Express pipeline. ETP also owns a 50% interest in Citrus, which owns 100% of FGT, an approximately 5,360-mile pipeline system that extends from South Texas through the Gulf Coast to south Florida. ETP operates the FEP and FGT joint ventures.

Our interstate transportation and storage segment includes Panhandle, which owns and operates a large natural gas open-access interstate pipeline network. The pipeline network, consisting of the Panhandle, Trunkline and Sea Robin transmission systems, serves customers in the Midwest, Gulf Coast and Midcontinent United States with a comprehensive array of transportation and storage services. In connection with its natural gas pipeline transmission and storage systems, Panhandle has five natural gas storage fields located in Illinois, Kansas, Louisiana, Michigan and Oklahoma. Southwest Gas operates four of these fields and Trunkline operates one.

The Rover Pipeline is a new 713-mile natural gas pipeline designed to transport 3.25 Bcf/d of domestically produced natural gas from the Marcellus and Utica Shale production areas to markets across the United States as well as into the Union Gas Dawn Storage Hub in Ontario, Canada, for redistribution back into the United States or into the Canadian market. Currently under construction, portions of the pipeline are in service transporting gas from processing plants in Eastern Ohio for delivery to other pipeline interconnects in Eastern Ohio as well as the Midwest Hub near Defiance, Ohio, where the gas will be delivered for distribution to markets across the United States. The Rover Pipeline Phase 1A and 1B are in service with a capacity of approximately 1.7 Bcf/d.

We also own a 50% interest in the MEP pipeline system, which is operated by KMI, and has the capability to transport up to 1.8 Bcf/d of natural gas.

Gulf States is a small interstate pipeline that uses cost-based rates and terms and conditions of service for shippers wishing to secure capacity for interstate transportation service. Rates charged are largely governed by long-term negotiated rate agreements.

The results from our interstate transportation and storage segment are primarily derived from the fees we earn from natural gas transportation and storage services.

Midstream Segment

The midstream natural gas industry is the link between the exploration and production of natural gas and the delivery of its components to end-use markets. The midstream industry consists of natural gas gathering, compression, treating, processing, storage, and transportation, and is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells and the proximity of storage facilities to production areas and end-use markets.

The natural gas gathering process begins with the drilling of wells into gas-bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems generally consist of a network of small diameter pipelines and, if necessary, compression systems, that collects natural gas from points near producing wells and transports it to larger pipelines for further transportation.

Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and to continue to produce for longer periods of time. As the pressure of a well declines, it becomes increasingly difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Field compression is typically used to lower the pressure of a gathering system. If field compression is not installed, then the remaining production in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise might not be produced.

Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations is higher in carbon dioxide, hydrogen sulfide or certain other contaminants. Treating plants remove carbon dioxide and hydrogen sulfide from natural gas to ensure that it meets pipeline quality specifications.

Some natural gas produced by a well does not meet the pipeline quality specifications established by downstream pipelines or is not suitable for commercial use and must be processed to remove the mixed NGL stream. In addition, some natural gas produced by a well, while not required to be processed, can be processed to take advantage of favorable margins for NGLs extracted from the gas stream. Natural gas processing involves the separation of natural gas into pipeline quality natural gas, or residue gas, and a mixed NGL stream.

Through our midstream segment, we own and operate natural gas and NGL gathering pipelines, natural gas processing plants, natural gas treating facilities and natural gas conditioning facilities with an aggregate processing, treating and conditioning capacity of approximately 12.3 Bcf/d. Our midstream segment focuses on the gathering, compression, treating, blending, and processing, and our operations are currently concentrated in major producing basins and shales, including the Austin Chalk trend and Eagle Ford Shale in South and Southeast Texas, the Permian Basin in West Texas and New Mexico, the Barnett Shale and Woodford Shale in North Texas, the Bossier Sands in East Texas, the Marcellus Shale in West Virginia and Pennsylvania, the Haynesville Shale in East Texas and Louisiana, and the Cotton Valley Shale in Louisiana. Many of our midstream assets are integrated with our intrastate transportation and storage assets.

Our midstream segment also includes a 60% interest in ELG, which operates natural gas gathering, oil pipeline, and oil stabilization facilities in South Texas, a 33.33% membership interest in Ranch Westex JV LLC, which processes natural gas delivered from the NGLs-rich shale formations in West Texas, a 75% membership interest in ORS, which operates a natural gas gathering system in the Utica shale in Ohio, and a 50% interest in Mi Vida JV, which operates a cryogenic processing plant and related facilities in West Texas, a 51% membership interest in Aqua – PVR, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania, and a 50% interest in Sweeny Gathering LP, which operates a natural gas gathering facility in South Texas.

Our midstream segment results are derived primarily from margins we earn for natural gas volumes that are gathered, transported, purchased and sold through our pipeline systems and the natural gas and NGL volumes processed at our processing and treating facilities.

NGL and Refined Products Transportation and Services Segment

Our NGL operations transport, store and execute acquisition and marketing activities utilizing a complementary network of pipelines, storage and blending facilities, and strategic off-take locations that provide access to multiple NGL markets.

Liquids transportation pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities to fractionation plants and storage facilities. NGL storage facilities are used for the storage of mixed NGLs, NGL products and petrochemical products owned by third parties in storage tanks and underground wells, which allow for the injection and withdrawal of such products at various times of the year to meet demand cycles. NGL fractionators separate mixed NGL streams into purity products, such as ethane, propane, normal butane, isobutane and natural gasoline.

Our NGL and refined products transportation and services segment includes approximately 4,300 miles of NGL pipelines, five NGL and propane fractionation facilities with an aggregate capacity of 545 MBbls/d and NGL storage facilities with aggregate working storage capacity of approximately 53 million Bbls. Four of our NGL and propane fractionation facilities and 50 million Bbls of our NGL storage capacity are located at Mont Belvieu, Texas, one NGL fractionation facility is located in Geismar, Louisiana, and the segment has 3 million Bbls of salt dome storage capacity near Hattiesburg, Mississippi. We are currently constructing a fifth and sixth fractionator in Mont Belvieu, Texas, which are expected to be operational in the third quarter of 2018 and the second quarter of 2019, respectively. The NGL pipelines primarily transport NGLs from the Permian and Delaware basins and the Barnett and Eagle Ford Shales to Mont Belvieu.

Terminalling services are facilitated by approximately 7 million Bbls of NGLs storage capacity, including approximately 1 million Bbls of storage at our Nederland, Texas terminal facility, 1 million Bbls of storage at our Inkster, Michigan terminal facility and 5 million Bbls at our Marcus Hook, Pennsylvania terminal facility (the “Marcus Hook Industrial Complex”). These operations also support our NGLs blending activities, including the use of our patented butane blending technology.

Liquids transportation revenue is principally generated from fees charged to customers under dedicated contracts or take-or-pay contracts. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported. Transportation fees are market-based, negotiated with customers and competitive with regional regulated pipelines.

NGL fractionation revenue is principally generated from fees charged to customers under take-or-pay contracts. Take-or-pay contracts have minimum payment obligations for throughput commitments requiring the customer to pay regardless of whether a fixed volume is fractionated from raw make into purity NGL products. Fractionation fees are market-based, negotiated with customers and competitive with other fractionators along the Gulf Coast.

NGL storage revenues are derived from base storage fees and throughput fees. Base storage fees are firm take-or-pay contracts on the volume of capacity reserved, regardless of the capacity actually used. Throughput fees are charged for providing ancillary services, including receipt and delivery and custody transfer fees.

This segment also includes revenues earned from the marketing of NGLs and processing and fractionating refinery off-gas. Marketing of NGLs primarily generates margin from selling ratable NGLs to end users and from optimizing storage assets. Processing and fractionation of refinery off-gas margin is generated from a percentage-of-proceeds of O-grade product sales and income sharing contracts, which are subject to market pricing of olefins and NGLs.

Our refined products operations provide transportation and terminalling services through the use of approximately 2,200 miles of refined products pipelines and approximately 40 active refined products marketing terminals. Our marketing terminals are located primarily in the northeast, midwest and southwest United States, with approximately 8 million Bbls of refined products storage capacity. Our refined products operations include our Eagle Point facility in New Jersey, which has approximately 6 million Bbls of refined products storage capacity. We also include our equity ownership interests in four refined products pipeline companies. The operations also perform terminalling activities at our Marcus Hook Industrial Complex. Our refined products operations utilize our integrated pipeline and terminalling assets, as well as acquisition and marketing activities, to service refined products markets in several regions in the United States.

Crude Oil Transportation and Services Segment

Our crude oil operations provide transportation, terminalling and acquisition and marketing services to crude oil markets throughout the southwest, midwest and northeastern United States. Included within the operations are approximately 9,360 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States and equity ownership interests in two crude oil pipelines. Our crude oil terminalling services operate with an aggregate storage capacity of approximately 33 million Bbls, including approximately 26 million Bbls at our Gulf Coast terminal in Nederland, Texas and approximately 3 million Bbls at our

Fort Mifflin terminal complex in Pennsylvania. Our crude oil acquisition and marketing activities utilize our pipeline and terminal assets, our proprietary fleet crude oil tractor trailers and truck unloading facilities, as well as third-party assets, to service crude oil markets principally in the mid-continent United States.

Revenues throughout our crude oil pipeline systems are generated from tariffs paid by shippers utilizing our transportation services. These tariffs are filed with the FERC and other state regulatory agencies, as applicable.

Our crude oil acquisition and marketing activities include the gathering, purchasing, marketing and selling of crude oil primarily in the mid-continent United States. Specifically, the crude oil acquisition and marketing activities include:

- purchasing crude oil at both the wellhead from producers, and in bulk from aggregators at major pipeline interconnections and trading locations;
- storing inventory during contango market conditions (when the price of crude oil for future delivery is higher than current prices);
- buying and selling crude oil of different grades, at different locations in order to maximize value;
- transporting crude oil using the pipelines, terminals and trucks or, when necessary or cost effective, pipelines, terminals or trucks owned and operated by third parties; and
- marketing crude oil to major integrated oil companies, independent refiners and resellers through various types of sale and exchange transactions.

In November 2016, we purchased a crude oil acquisition and marketing business from Vitol, with operations based in the Permian Basin, Texas. Included in the acquisition was a significant acreage dedication from an investment-grade Permian producer.

All Other Segment

Segments below the quantitative thresholds are classified as “All other.” These include the following:

- We own an equity method investment in limited partnership units of Sunoco LP. As of December 31, 2017, our investment consisted of 43.5 million units, representing 43.6% of Sunoco LP’s total outstanding common units. Subsequent to Sunoco LP’s repurchase of a portion of its common units on February 7, 2018, our investment consists of 26.2 million units, representing 31.8% of Sunoco LP’s total outstanding common units.
- Our wholly-owned subsidiary, Sunoco, Inc., owns an approximate 33% non-operating interest in PES, a refining joint venture with The Carlyle Group, L.P., which owns a refinery in Philadelphia.

  PES Holdings, LLC ("PES Holdings") and eight affiliates filed for Chapter 11 bankruptcy protection on January 21, 2018 in the United States Bankruptcy Court for the District of Delaware to implement a prepackaged reorganization plan that will allow its shareholders to retain a minority stake. PES Holdings' Chapter 11 Plan (“Plan”) proposes to inject $260 million in new capital into PES Holdings, cut debt service obligations by about $35 million per year and remove debt maturities before 2022. Under that Plan, PES Holdings’ non-debtor parent, PES, in which ETP holds an indirect 33% equity interest, will provide a $65 million cash contribution in exchange for a 25% stake in the reorganized debtor. After the restructuring, the proportionate ownership of Carlyle Group, L.P. and ETP in PES Holdings will be 16.26% and 8.13%, respectively. Finally, Sunoco Logistics Partners Operations L.P. (“SXL Operating Partnership”), a subsidiary of ETP, is providing an additional $75 million exit loan ranked *pari passu* with the other debt. SXL Operating Partnership’s, PES Holdings’ and ETP’s current contracts will be assumed, without any impairments, in the Chapter 11, and business operations will continue uninterrupted. The financial reorganization is expected to complete in the first quarter of 2018.
- We conduct marketing operations in which we market the natural gas that flows through our gathering and intrastate transportation assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other suppliers and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices of natural gas, less the costs of transportation. For the off-system gas, we purchase gas or act as an agent for small independent producers that may not have marketing operations.
- We own a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas.
- We own 100% of the membership interests of Energy Transfer Group, L.L.C. (“ETG”), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. (“ETT”). ETT provides compression services to customers engaged in the transportation of natural gas, including our other segments.

- We own a 40% interest in the parent of LCL, which is developing a LNG liquefaction project, as described further under "Asset Overview – All Other" below.
- We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. We also own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management. These assets are primarily owned through CDM and CDM E&T. As discussed in "Recent Developments" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," in January 2018, we entered into an agreement to contribute these assets to USAC.
- We are involved in the management of coal and natural resources properties and the related collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. These operations also include end-user coal handling facilities.
- We also own PEI Power Corp. and PEI Power II, which own and operate a facility in Pennsylvania that generates a total of 75 megawatts of electrical power.

Asset Overview

The descriptions below include summaries of significant assets within the Partnership's reportable segments. Amounts, such as capacities, volumes and miles included in the descriptions below are approximate and are based on information currently available; such amounts are subject to change based on future events or additional information.

Intrastate Transportation and Storage

The following details our pipelines and storage facilities in the intrastate transportation and storage segment:

Description of Assets	Ownership Interest (%)	Miles of Natural Gas Pipeline	Pipeline Throughput Capacity (Bcf/d)	Working Storage Capacity (Bcf/d)
ET Fuel System	100%	2,780	5.2	11.2
Oasis Pipeline	100%	750	2.3	—
HPL System	100%	3,920	5.3	52.5
East Texas Pipeline	100%	460	2.4	—
RIGS Haynesville Partnership Co.	49.99%	450	2.1	—
Comanche Trail Pipeline	16%	195	1.1	—
Trans-Pecos Pipeline	16%	143	1.4	—

The following information describes our principal intrastate transportation and storage assets:

- The ET Fuel System serves some of the most prolific production areas in the United States and is comprised of intrastate natural gas pipeline and related natural gas storage facilities. The ET Fuel System has many interconnections with pipelines providing direct access to power plants, other intrastate and interstate pipelines, and has bi-directional capabilities. It is strategically located near high-growth production areas and provides access to the Waha Hub near Midland, Texas, the Katy Hub near Houston, Texas and the Carthage Hub in East Texas, the three major natural gas trading centers in Texas.

  The ET Fuel System also includes our Bethel natural gas storage facility, with a working capacity of 6.0 Bcf, an average withdrawal capacity of 300 MMcf/d and an injection capacity of 75 MMcf/d, and our Bryson natural gas storage facility, with a working capacity of 5.2 Bcf, an average withdrawal capacity of 120 MMcf/d and an average injection capacity of 96 MMcf/d. Storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements that extend through 2023.

  In addition, the ET Fuel System is integrated with our Godley processing plant which gives us the ability to bypass the plant when processing margins are unfavorable by blending the untreated natural gas from the North Texas System with natural gas on the ET Fuel System while continuing to meet pipeline quality specifications.
- The Oasis Pipeline is primarily a 36-inch natural gas pipeline. It has bi-directional capabilities with approximately 1.2 Bcf/d of throughput capacity moving west-to-east and greater than 750 MMcf/d of throughput capacity moving east-to-west. The Oasis pipeline connects to the Waha and Katy market hubs and has many interconnections with other pipelines, power plants, processing facilities, municipalities and producers.

The Oasis pipeline is integrated with our Southeast Texas System and is an important component to maximizing our Southeast Texas System's profitability. The Oasis pipeline enhances the Southeast Texas System by (i) providing access for natural gas on the Southeast Texas System to other third-party supply and market points and interconnecting pipelines and (ii) allowing us to bypass our processing plants and treating facilities on the Southeast Texas System when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

- The HPL System is an extensive network of intrastate natural gas pipelines, an underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from South Texas, the Gulf Coast of Texas, East Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City and other cities located along the Gulf Coast of Texas. The HPL System is well situated to gather and transport gas in many of the major gas producing areas in Texas including a strong presence in the key Houston Ship Channel and Katy Hub markets, allowing us to play an important role in the Texas natural gas markets. The HPL System also offers its shippers off-system opportunities due to its numerous interconnections with other pipeline systems, its direct access to multiple market hubs at Katy, the Houston Ship Channel and Agua Dulce, as well as our Bammel storage facility.

  The Bammel storage facility has a total working gas capacity of approximately 52.5 Bcf, a peak withdrawal rate of 1.3 Bcf/d and a peak injection rate of 0.6 Bcf/d. The Bammel storage facility is located near the Houston Ship Channel market area and the Katy Hub, and is ideally suited to provide a physical backup for on-system and off-system customers. As of December 31, 2017, we had approximately 10.8 Bcf committed under fee-based arrangements with third parties and approximately 36.9 Bcf stored in the facility for our own account.

- The East Texas Pipeline connects three treating facilities, one of which we own, with our Southeast Texas System. The East Texas pipeline serves producers in East and North Central Texas and provided access to the Katy Hub. The East Texas pipeline expansions include the 36-inch East Texas extension to connect our Reed compressor station in Freestone County to our Grimes County compressor station, the 36-inch Katy expansion connecting Grimes to the Katy Hub, and the 42-inch Southeast Bossier pipeline connecting our Cleburne to Carthage pipeline to the HPL System.

- RIGS is a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets. The Partnership owns a 49.99% general partner interest in RIGS.

- Comanche Trail is a 195-mile intrastate pipeline that delivers natural gas from the Waha Hub near Midland, Texas to the United States/Mexico border near San Elizario, Texas. The Partnership owns a 16% membership interest in and operates Comanche Trail.

- Trans-Pecos is a 143-mile intrastate pipeline that delivers natural gas from the Waha Hub near Midland, Texas to the United States/Mexico border near Presidio, Texas. The Partnership owns a 16% membership interest in and operates Trans-Pecos.

Interstate Transportation and Storage

The following details our pipelines in the interstate transportation and storage segment:

Description of Assets	Ownership Interest (%)	Miles of Natural Gas Pipeline	Pipeline Throughput Capacity (Bcf/d)	Working Gas Capacity (Bcf/d)
Florida Gas Transmission Pipeline	50%	5,360	3.1	—
Transwestern Pipeline	100%	2,570	2.1	—
Panhandle Eastern Pipe Line	100%	5,980	2.8	83.9
Trunkline Gas Pipeline	100%	2,220	0.9	13.0
Tiger Pipeline	100%	195	2.4	—
Fayetteville Express Pipeline	50%	185	2.0	—
Sea Robin Pipeline	100%	830	2.0	—
Rover Pipeline	32.6%	713	3.25	—
Midcontinent Express Pipeline	50%	500	1.8	—
Gulf States	100%	10	0.1	—

The following information describes our principal interstate transportation and storage assets:

- The Florida Gas Transmission Pipeline ("FGT") is an open-access interstate pipeline system with a mainline capacity of 3.1 Bcf/d and approximately 5,360 miles of pipelines extending from south Texas through the Gulf Coast region of the United States to south Florida. The FGT system receives natural gas from various onshore and offshore natural gas producing basins. FGT is the principal transporter of natural gas to the Florida energy market, delivering over 66% of the natural gas consumed in the state. In addition, FGT's system operates and maintains over 81 interconnects with major interstate and intrastate natural gas pipelines, which provide FGT's customers access to diverse natural gas producing regions. FGT's customers include electric utilities, independent power producers, industrials and local distribution companies. FGT is owned by Citrus, a 50/50 joint venture with KMI.
- The Transwestern Pipeline is an open-access interstate natural gas pipeline extending from the gas producing regions of West Texas, eastern and northwestern New Mexico, and southern Colorado primarily to pipeline interconnects off the east end of its system and to pipeline interconnects at the California border. The Transwestern Pipeline has bi-directional capabilities and access to three significant gas basins: the Permian Basin in West Texas and eastern New Mexico; the San Juan Basin in northwestern New Mexico and southern Colorado; and the Anadarko Basin in the Texas and Oklahoma panhandles. Natural gas sources from the San Juan Basin and surrounding producing areas can be delivered eastward to Texas intrastate and mid-continent connecting pipelines and natural gas market hubs as well as westward to markets in Arizona, Nevada and California. Transwestern's Phoenix Lateral Pipeline, with a throughput capacity of 660 MMcf/d, connects the Phoenix area to the Transwestern mainline. Transwestern's customers include local distribution companies, producers, marketers, electric power generators and industrial end-users.
- The Panhandle Eastern Pipe Line's transmission system consists of four large diameter pipelines with bi-directional capabilities, extending approximately 1,300 miles from producing areas in the Anadarko Basin of Texas, Oklahoma and Kansas through Missouri, Illinois, Indiana, Ohio and into Michigan.
- The Trunkline Gas Pipeline's transmission system consists of one large diameter pipeline with bi-directional capabilities, extending approximately 1,400 miles from the Gulf Coast areas of Texas and Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Illinois, Indiana and Michigan.
- The Tiger Pipeline is an approximately 195-mile interstate natural gas pipeline with bi-directional capabilities, that connects to our dual 42-inch pipeline system near Carthage, Texas, extends through the heart of the Haynesville Shale and ends near Delhi, Louisiana, with interconnects to at least seven interstate pipelines at various points in Louisiana.
- The Fayetteville Express Pipeline is an approximately 185-mile interstate natural gas pipeline that originates near Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The Fayetteville Express Pipeline is owned by a 50/50 joint venture with KMI.
- The Sea Robin Pipeline's transmission system consists of two offshore Louisiana natural gas supply systems extending approximately 120 miles into the Gulf of Mexico.
- The Rover Pipeline is a new 713-mile natural gas pipeline designed to transport 3.25 Bcf/d of domestically produced natural gas from the Marcellus and Utica Shale production areas to markets across the United States as well as into the Union Gas Dawn Storage Hub in Ontario, Canada, for redistribution back into the United States or into the Canadian market.
- The Midcontinent Express Pipeline is an approximately 500-mile interstate pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipeline System in Butler, Alabama. The Midcontinent Express Pipeline is owned by a 50/50 joint venture with KMI.
- Gulf States owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

Midstream

The following details our assets in the midstream segment:

Description of Assets	Net Gas Processing Capacity (MMcf/d)	Net Gas Treating Capacity (MMcf/d)
South Texas Region:		
Southeast Texas System	410	510
Eagle Ford System	1,920	1,808
Ark-La-Tex Region	1,025	1,186
North Central Texas Region	715	212
Permian Region	1,943	1,580
Mid-Continent Region	885	20
Eastern Region	—	70

The following information describes our principal midstream assets:

South Texas Region:

- The Southeast Texas System is an integrated system that gathers, compresses, treats, processes, dehydrates and transports natural gas from the Austin Chalk trend and Eagle Ford shale formation. The Southeast Texas System is a large natural gas gathering system covering thirteen counties between Austin and Houston. This system is connected to the Katy Hub through the East Texas Pipeline and is also connected to the Oasis Pipeline. The Southeast Texas System includes two natural gas processing plant (La Grange and Alamo) with aggregate capacity of 410 MMcf/d and natural gas treating facilities with aggregate capacity of 510 MMcf/d. The La Grange and Alamo processing plants are natural gas processing plants that process the rich gas that flows through our gathering system to produce residue gas and NGLs. Residue gas is delivered into our intrastate pipelines and NGLs are delivered into our NGL pipelines to Lone Star.

  Our treating facilities remove carbon dioxide and hydrogen sulfide from natural gas gathered into our system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications.

- The Eagle Ford Gathering System consists of 30-inch and 42-inch natural gas gathering pipelines with over 1.4 Bcf/d of capacity originating in Dimmitt County, Texas, and extending to both our King Ranch gas plant in Kleberg County, Texas and Jackson plant in Jackson County, Texas. The Eagle Ford Gathering System includes four processing plants (Chisholm, Kenedy, Jackson and King Ranch) with aggregate capacity of 1.92 Bcf/d and multiple natural gas treating facilities with combined capacity of 1.81 Bcf/d. Our Chisholm, Kenedy, Jackson and King Ranch processing plants are connected to our intrastate transportation pipeline systems for deliveries of residue gas and are also connected with our NGL pipelines for delivery of NGLs to Lone Star.

Ark-La-Tex Region:

- Our Northern Louisiana assets are comprised of several gathering systems in the Haynesville Shale with access to multiple markets through interconnects with several pipelines, including our Tiger Pipeline. Our Northern Louisiana assets include the Bistineau, Creedence, and Tristate Systems, which collectively include three natural gas treating facilities, with aggregate capacity of 1.19 Bcf/d.
- Our PennTex Midstream System is primarily located in Lincoln Parish, Louisiana, and consists of the Lincoln Parish plant, a 200 MMcf/d design-capacity cryogenic natural gas processing plant located near Arcadia, Louisiana, the Mt. Olive plant, a 200 MMcf/d design-capacity cryogenic natural gas processing plant located near Ruston, Louisiana, with on-site liquids handling facilities for inlet gas; a 35-mile rich gas gathering system that provides producers with access to our processing plants and third-party processing capacity; a 15-mile residue gas pipeline that provides market access for natural gas from our processing plants, including connections with pipelines that provide access to the Perryville Hub and other markets in the Gulf Coast region; and a 40-mile NGL pipeline that provides connections to the Mont Belvieu market for NGLs produced from our processing plants.
- The Ark-La-Tex assets gather, compress, treat and dehydrate natural gas in several parishes in north and west Louisiana and several counties in East Texas. These assets also include cryogenic natural gas processing facilities, a refrigeration plant, a conditioning plant, amine treating plants, and an interstate NGL pipeline. Collectively, the eight natural gas processing

facilities (Dubach, Dubberly, Lisbon, Salem, Elm Grove, Minden, Ada and Brookeland) have an aggregate capacity of 1.03 Bcf/d.

- Through the gathering and processing systems described above and their interconnections with RIGS in north Louisiana, we offer producers wellhead-to-market services, including natural gas gathering, compression, processing, treating and transportation.

North Central Texas Region:

- The North Central Texas System is an integrated system located in four counties in North Central Texas that gathers, compresses, treats, processes and transports natural gas from the Barnett and Woodford Shales. Our North Central Texas assets include our Godley and Crescent plants, which process rich gas produced from the Barnett Shale and STACK play, with aggregate capacity of 715 MMcf/d and aggregate treating capacity of 212 MMcf/d. The Godley plant is integrated with the ET Fuel System.

Permian Region:

- The Permian Basin Gathering System offers wellhead-to-market services to producers in eleven counties in West Texas, as well as two counties in New Mexico which surround the Waha Hub, one of Texas's developing NGL-rich natural gas market areas. As a result of the proximity of our system to the Waha Hub, the Waha Gathering System has a variety of market outlets for the natural gas that we gather and process, including several major interstate and intrastate pipelines serving California, the mid-continent region of the United States and Texas natural gas markets. The NGL market outlets includes Lone Star's liquids pipelines. The Permian Basin Gathering System includes ten processing facilities (Waha, Coyanosa, Red Bluff, Halley, Jal, Keyston, Tippet, Orla, Panther and Rebel) with an aggregate processing capacity of 1.62 Bcf/d, treating capacity of 1.58 Bcf/d, and one natural gas conditioning facility with aggregate capacity of 200 MMcf/d.
- We own a 50% membership interest in Mi Vida JV, a joint venture which owns a 200 MMcf/d cryogenic processing plant in West Texas. We operate the plant and related facilities on behalf of Mi Vida JV.
- We own a 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGL-rich Bone Spring and Avalon Shale formations in West Texas. The joint venture owns a 25 MMcf/d refrigeration plant and a 125 MMcf/d cryogenic processing plant.

Mid-Continent Region:

- The Mid-Continent Systems are located in two large natural gas producing regions in the United States, the Hugoton Basin in southwest Kansas, and the Anadarko Basin in western Oklahoma and the Texas Panhandle. These mature basins have continued to provide generally long-lived, predictable production volume. Our Mid-Continent assets are extensive systems that gather, compress and dehydrate low-pressure gas. The Mid-Continent Systems include fourteen natural gas processing facilities (Mocane, Beaver, Antelope Hills, Woodall, Wheeler, Sunray, Hemphill, Phoenix, Hamlin, Spearman, Red Deer, Lefors, Cargray and Gray) with an aggregate capacity of 885 MMcf/d and one natural gas treating facility with aggregate capacity of 20 MMcf/d.
- We operate our Mid-Continent Systems at low pressures to maximize the total throughput volumes from the connected wells. Wellhead pressures are therefore adequate to allow for flow of natural gas into the gathering lines without the cost of wellhead compression.
- We also own the Hugoton Gathering System that has 1,900 miles of pipeline extending over nine counties in Kansas and Oklahoma. This system is operated by a third party.

Eastern Region:

- The Eastern Region assets are located in nine counties in Pennsylvania, three counties in Ohio, three counties in West Virginia, and gather natural gas from the Marcellus and Utica basins. Our Eastern Region assets include approximately 500 miles of natural gas gathering pipeline, natural gas trunklines, fresh-water pipelines, and nine gathering and processing systems. The fresh water pipeline system and Ohio gathering assets are held by jointly-owned entities.
- We also own a 51% membership interest in Aqua – PVR, a joint venture that transports and supplies fresh water to natural gas producers drilling in the Marcellus Shale in Pennsylvania.
- We and Traverse ORS LLC, a subsidiary of Traverse Midstream Partners LLC, own a 75% and 25% membership interest, respectively, in the ORS joint venture. On behalf of ORS, we operate its Ohio Utica River System (the "ORS System"), which consists of 47 miles of 36-inch and 13 miles of 30-inch gathering trunklines that delivers up to 2.1 Bcf/d to Rockies Express Pipeline ("REX"), Texas Eastern Transmission, and others.

NGL and Refined Products Transportation and Services

The following details the assets in our NGL and refined products transportation and services segment:

Description of Assets	Miles of Liquids Pipeline [2]	Pipeline Throughput Capacity (MBbls/d)	NGL Fractionation / Processing Capacity (MBbls/d)	Working Storage Capacity (MBbls)
Liquids Pipelines:				
Lone Star Express	535	507	—	—
West Texas Gateway Pipeline	512	240	—	—
Lone Star	1,617	120	—	—
Mariner East	300	70	—	—
Mariner South	67	200	—	—
Mariner West	395	50	—	—
Other NGL Pipelines	645	591	—	—
Liquids Fractionation and Services Facilities:				
Mont Belvieu Facilities	163	42	520	50,000
Sea Robin Processing Plant[1]	—	—	26	—
Refinery Services[1]	103	—	25	—
Hattiesburg Storage Facilities	—	—	—	3,000
NGLs Terminals:				
Nederland	—	—	—	1,000
Marcus Hook Industrial Complex	—	—	90	5,000
Inkster	—	—	—	1,000
Refined Products Pipelines	2,200	800	—	—
Refined Products Terminals:				
Eagle Point	—	—	—	6,000
Marcus Hook Industrial Complex	—	—	—	1,000
Marcus Hook Tank Farm	—	—	—	2,000
Marketing Terminals	—	—	—	8,000

(1) Additionally, the Sea Robin Processing Plant and Refinery Services have residue capacities of 850 MMcf/d and 54 MMcf/d, respectively.

(2) Miles of pipeline as reported to PHMSA.

The following information describes our principal NGL and refined products transportation and services assets:

- The Lone Star Express System is an interstate NGL pipeline consisting of 24-inch and 30-inch long-haul transportation pipeline that delivers mixed NGLs from processing plants in the Permian Basin, the Barnett Shale, and from East Texas to the Mont Belvieu NGL storage facility.
- The West Texas Gateway Pipeline transports NGLs produced in the Permian and Delaware Basins and the Eagle Ford Shale to Mont Belvieu, Texas.
- The Mariner East pipeline transports NGLs from the Marcellus and Utica Shales areas in Western Pennsylvania, West Virginia and Eastern Ohio to destinations in Pennsylvania, including our Marcus Hook Industrial Complex on the Delaware River, where they are processed, stored and distributed to local, domestic and waterborne markets. The first phase of the project, referred to as Mariner East 1, consisted of interstate and intrastate propane and ethane service and commenced operations in the fourth quarter of 2014 and the first quarter of 2016, respectively. The second phase of the project, referred to as Mariner East 2, will expand the total takeaway capacity to 345 MBbls/d for interstate and intrastate propane, ethane and butane service, and is expected to commence operations in the second quarter of 2018.

- The Mariner South pipeline is part of a joint project with Lone Star to deliver export-grade propane and butane products from Lone Star's Mont Belvieu, Texas storage and fractionation complex to our marine terminal in Nederland, Texas.
- The Mariner West pipeline provides transportation of ethane from the Marcellus shale processing and fractionating areas in Houston, Pennsylvania to Marysville, Michigan and the Canadian border. Mariner West commenced operations in the fourth quarter of 2013, with capacity to transport approximately 50 MBbls/d.
- Refined products pipelines include approximately 2,200 miles of refined products pipelines in several regions of the United States. The pipelines primarily provide transportation in the northeast, midwest, and southwest United States markets. These operations include our controlling financial interest in Inland Corporation ("Inland"). The mix of products delivered varies seasonally, with gasoline demand peaking during the summer months, and demand for heating oil and other distillate fuels peaking in the winter. In addition, weather conditions in the areas served by the refined products pipelines affect both the demand for, and the mix of, the refined products delivered through the pipelines, although historically, any overall impact on the total volume shipped has been short-term. The products transported in these pipelines include multiple grades of gasoline, and middle distillates, such as heating oil, diesel and jet fuel. Rates for shipments on these product pipelines are regulated by the FERC and other state regulatory agencies, as applicable.
- Other NGL pipelines include the 127-mile Justice pipeline with capacity of 375 MBbls/d, the 45-mile Freedom pipeline with a capacity of 56 MBbls/d, the 20-mile Spirit pipeline with a capacity of 20 MBbls/d and a 50% interest in the 87-mile Liberty pipeline with a capacity of 140 MBbls/d.
- Our Mont Belvieu storage facility is an integrated liquids storage facility with over 50 million Bbls of salt dome capacity providing 100% fee-based cash flows. The Mont Belvieu storage facility has access to multiple NGL and refined products pipelines, the Houston Ship Channel trading hub, and numerous chemical plants, refineries and fractionators.
- Our Mont Belvieu fractionators handle NGLs delivered from several sources, including the Lone Star Express pipeline and the Justice pipeline. Fractionator V is currently under construction and is scheduled to be operational by the third quarter of 2018.
- Sea Robin is a rich gas processing plant located on the Sea Robin Pipeline in southern Louisiana. The plant is connected to nine interstate and four intrastate residue pipelines, as well as various deep-water production fields.
- Refinery Services consists of a refinery off-gas processing unit and an O-grade NGL fractionation / Refinery-Grade Propylene ("RGP") splitting complex located along the Mississippi River refinery corridor in southern Louisiana. The off-gas processing unit cryogenically processes refinery off-gas, and the fractionation / RGP splitting complex fractionates the streams into higher value components. The O-grade fractionator and RGP splitting complex, located in Geismar, Louisiana, is connected by approximately 103 miles of pipeline to the Chalmette processing plant, which has a processing capacity of 54 MMcf/d.
- The Hattiesburg storage facility is an integrated liquids storage facility with approximately 3 million Bbls of salt dome capacity, providing 100% fee-based cash flows.
- The Nederland terminal, in addition to crude oil activities, also provides approximately 1 million Bbls of storage and distribution services for NGLs in connection with the Mariner South pipeline, which provides transportation of propane and butane products from the Mont Belvieu region to the Nederland terminal, where such products can be exported via ship.
- The Marcus Hook Industrial Complex includes fractionation, terminalling and storage assets, with a capacity of approximately 2 million Bbls of NGL storage capacity in underground caverns, 3 million Bbls of above-ground refrigerated storage, and related commercial agreements. The terminal has a total active refined products storage capacity of approximately 1 million Bbls. The facility can receive NGLs and refined products via marine vessel, pipeline, truck and rail, and can deliver via marine vessel, pipeline and truck. In addition to providing NGLs storage and terminalling services to both affiliates and third-party customers, the Marcus Hook Industrial Complex currently serves as an off-take outlet for the Mariner East 1 pipeline, and will provide similar off-take capabilities for the Mariner East 2 pipeline when it commences operations.
- The Inkster terminal, located near Detroit, Michigan, consists of multiple salt caverns with a total storage capacity of approximately 1 million Bbls of NGLs. We use the Inkster terminal's storage in connection with the Toledo North pipeline system and for the storage of NGLs from local producers and a refinery in Western Ohio. The terminal can receive and ship by pipeline in both directions and has a truck loading and unloading rack.
- We have approximately 40 refined products terminals with an aggregate storage capacity of approximately 8 million Bbls that facilitate the movement of refined products to or from storage or transportation systems, such as a pipeline, to other transportation systems, such as trucks or other pipelines. Each facility typically consists of multiple storage tanks and is equipped with automated truck loading equipment that is operational 24 hours a day.
- In addition to crude oil service, the Eagle Point terminal can accommodate three marine vessels (ships or barges) to receive and deliver refined products to outbound ships and barges. The tank farm has a total active refined products storage capacity

of approximately 6 million Bbls, and provides customers with access to the facility via ship, barge and pipeline. The terminal can deliver via ship, barge, truck or pipeline, providing customers with access to various markets. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage.

- The Marcus Hook Tank Farm has a total refined products storage capacity of approximately 2 million Bbls of refined products storage. The tank farm historically served Sunoco Inc.'s Marcus Hook refinery and generated revenue from the related throughput and storage. In 2012, the main processing units at the refinery were idled in connection with Sunoco Inc.'s exit from its refining business. The terminal continues to receive and deliver refined products via pipeline and now primarily provides terminalling services to support movements on our refined products pipelines.
- The Eastern refined products pipelines consists of approximately 470 miles of 6-inch to 24-inch diameters refined product pipelines in Eastern, Central and North Central Pennsylvania, approximately 162 miles of 8-inch refined products pipeline in western New York and approximately 182 miles of various diameters refined products pipeline in New Jersey (including 80 miles of the 16-inch diameter Harbor Pipeline).
- The Mid-Continent refined products pipelines primarily consists of approximately 212 miles of 3-inch to 12-inch refined products pipelines in Ohio, approximately 85 miles of 6-inch to 12-inch refined products pipeline in Western Pennsylvania and approximately 52 miles of 8-inch refined products pipeline in Michigan.
- The Southwest refined products pipelines is located in Eastern Texas and consists primarily of approximately 300 miles of 8-inch diameter refined products pipeline.
- The Inland refined products pipeline, approximately 350 miles of pipeline in Ohio, consists of 72 miles of 12-inch diameter refined products pipeline in Northwest Ohio, 205 miles of 10-inch diameter refined products pipeline in vicinity of Columbus, Ohio, 53 miles of 8-inch diameter refined products pipeline in western Ohio and the remaining refined products pipeline primarily consists of 5-inch diameter pipeline in Northeast Ohio.

Crude Oil Transportation and Services

The following details our pipelines and terminals in the crude oil transportation and services segment:

Description of Assets	Miles of Crude Pipeline [1]	Working Storage Capacity (MBbls)
Dakota Access Pipeline	1,172	—
Energy Transfer Crude Oil Pipeline	743	—
Bayou Bridge Pipeline	49	—
Permian Express Pipelines	1,712	—
Other Crude Oil Pipelines	5,682	—
Nederland Terminal	—	26,000
Fort Mifflin Terminal	—	570
Eagle Point Terminal	—	1,000
Midland Terminal	—	2,000
Marcus Hook Industrial Complex	—	1,000
Patoka, Illinois Terminal	—	2,000

[1] Miles of pipeline as reported to PHMSA.

Our crude oil operations consist of an integrated set of pipeline, terminalling, and acquisition and marketing assets that service the movement of crude oil from producers to end-user markets. The following details our assets in the crude oil transportation and services segment:

Crude Oil Pipelines

Our crude oil pipelines consist of approximately 9,358 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States, including our wholly-owned interests in West Texas Gulf, Permian Express Terminal LLC ("PET"), and Mid-Valley Pipeline Company ("Mid-Valley"). Additionally, we have equity ownership interests in two crude oil pipelines. Our crude oil pipelines provide access to several trading hubs, including the largest trading hub for crude oil in the United States located

in Cushing, Oklahoma, and other trading hubs located in Midland, Colorado City and Longview, Texas. Our crude oil pipelines also deliver to and connect with other pipelines that deliver crude oil to a number of refineries.

- *Bakken Pipeline.* Dakota Access and ETCO are collectively referred to as the "Bakken Pipeline." The Bakken Pipeline is a 1,915 mile pipeline with an initial capacity of 470 MBbls/d, expandable to 570 MBbls/d, that transports domestically produced crude oil from the Bakken/Three Forks production areas in North Dakota to a storage and terminal hub outside of Patoka, Illinois, or to gulf coast connections including our crude terminal in Nederland Texas.

  The pipeline transports light, sweet crude oil from North Dakota to major refining markets in the Midwest and Gulf Coast regions.

  Dakota Access went into service on June 1, 2017 and consists of approximately 1,172 miles of 30-inch diameter pipeline traversing North Dakota, South Dakota, Iowa and Illinois. Crude oil transported on the Dakota Access originates at six terminal locations in the North Dakota counties of Mountrail, Williams and McKenzie. The pipeline delivers the crude oil to a hub outside of Patoka, Illinois where it can be delivered to the ETCO Pipeline for delivery to the Gulf Coast, or can be transported via other pipelines to refining markets throughout the Midwest.

  ETCO went into service on June 1, 2017 and consists of more than 743 miles consisting of 678 miles of mostly 30-inch converted natural gas pipeline and 65 miles of new 30-inch pipeline from Patoka, Illinois to Nederland, Texas, where the crude oil can be refined or further transported to additional refining markets.

- *Bayou Bridge Pipeline.* The Bayou Bridge Pipeline is a joint venture between ETP and Phillips 66, in which ETP has a 60% ownership interest and serves as the operator of the pipeline. Phase I of the pipeline, which consists of a 30-inch pipeline from Nederland, Texas to Lake Charles, Louisiana, went into service in April 2016. Phase II of the pipeline, which will consist of 24-inch pipe from Lake Charles, Louisiana to St. James, Louisiana, is expected to be completed in the second half of 2018.

  When completed the Bayou Bridge Pipeline will have a capacity expandable to approximately 480 MBbls/d of light and heavy crude oil from different sources to the St. James crude oil hub, which is home to important refineries located in the Gulf Coast region.

- *Permian Express Pipelines.* The Permian Express pipelines are part of the PEP joint venture and include Permian Express 1, Permian Express 2, Permian Longview and Louisiana Access pipelines, as well as the Longview to Louisiana and Pegasus pipelines contributed to this joint venture by ExxonMobil. These pipelines are comprised of crude oil trunk pipelines and crude oil gathering pipelines in Texas and Oklahoma and provide takeaway capacity from the Permian Basin, which origins in multiple locations in Western Texas.

- Other Crude Oil pipelines include the Mid-Valley pipeline system which originates in Longview, Texas and passes through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky and Ohio and terminates in Samaria, Michigan. This pipeline provides crude oil to a number of refineries, primarily in the Midwest United States.

  In addition, we own a crude oil pipeline that runs from Marysville, Michigan to Toledo, Ohio, and a truck injection point for local production at Marysville. This pipeline receives crude oil from the Enbridge pipeline system for delivery to refineries located in Toledo, Ohio and to MPLX's Samaria, Michigan tank farm, which supplies its Marathon Petroleum Corporation's refinery in Detroit, Michigan.

  We also own and operate crude oil pipeline and gathering systems in Oklahoma. We have the ability to deliver substantially all of the crude oil gathered on our Oklahoma system to Cushing. We are one of the largest purchasers of crude oil from producers in the state, and our crude oil acquisition and marketing activities business is the primary shipper on our Oklahoma crude oil system.

Crude Oil Terminals

- *Nederland.* The Nederland terminal, located on the Sabine-Neches waterway between Beaumont and Port Arthur, Texas, is a large marine terminal providing storage and distribution services for refiners and other large transporters of crude oil and NGLs. The terminal receives, stores, and distributes crude oil, NGLs, feedstocks, lubricants, petrochemicals, and bunker oils (used for fueling ships and other marine vessels), and also blends lubricants. The terminal currently has a total storage capacity of approximately 26 million Bbls in approximately 150 above ground storage tanks with individual capacities of up to 660 MBbls.

  The Nederland terminal can receive crude oil at four of its five ship docks and four barge berths. The four ship docks are capable of receiving over 2 million Bbls/d of crude oil. In addition to our crude oil pipelines, the terminal can also receive crude oil through a number of other pipelines, including the DOE. The DOE pipelines connect the terminal to the United States Strategic Petroleum Reserve's West Hackberry caverns at Hackberry, Louisiana and Big Hill caverns near Winnie, Texas, which have an aggregate storage capacity of approximately 395 million Bbls.

The Nederland Terminal can deliver crude oil and other petroleum products via pipeline, barge and ship. The terminal has two ship docks and three barge berths that are capable of delivering crude oils for international transport. In total, the terminal is capable of delivering over 2 million Bbls/d of crude oil to our crude oil pipelines or a number of third-party pipelines including the DOE. The Nederland terminal generates crude oil revenues primarily by providing term or spot storage services and throughput capabilities to a number of customers.

- *Fort Mifflin*. The Fort Mifflin terminal complex is located on the Delaware River in Philadelphia, Pennsylvania and includes the Fort Mifflin terminal, the Hog Island wharf, the Darby Creek tank farm and connecting pipelines. Revenues are generated from the Fort Mifflin terminal complex by charging fees based on throughput.

  The Fort Mifflin terminal contains two ship docks with freshwater drafts and a total storage capacity of approximately 570 MBbls. Crude oil and some refined products enter the Fort Mifflin terminal primarily from marine vessels on the Delaware River. One Fort Mifflin dock is designed to handle crude oil from very large crude carrier-class tankers and smaller crude oil vessels. The other dock can accommodate only smaller crude oil vessels.

  The Hog Island wharf is located next to the Fort Mifflin terminal on the Delaware River and receives crude oil via two ship docks, one of which can accommodate crude oil tankers and smaller crude oil vessels, and the other of which can accommodate some smaller crude oil vessels.

  The Darby Creek tank farm is a primary crude oil storage terminal for the Philadelphia refinery, which is operated by PES under a joint venture with Sunoco, Inc. This facility has a total storage capacity of approximately 3 million Bbls. Darby Creek receives crude oil from the Fort Mifflin terminal and Hog Island wharf via our pipelines. The tank farm then stores the crude oil and transports it to the PES refinery via our pipelines.

- *Eagle Point*. The Eagle Point terminal is located in Westville, New Jersey and consists of docks, truck loading facilities and a tank farm. The docks are located on the Delaware River and can accommodate three marine vessels (ships or barges) to receive and deliver crude oil, intermediate products and refined products to outbound ships and barges. The tank farm has a total active storage capacity of approximately 1 million Bbls and can receive crude oil via barge and rail and deliver via ship and barge, providing customers with access to various markets. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage.

- *Midland*. The Midland terminal is located in Midland, Texas and was acquired in November 2016 from Vitol. The facility includes approximately 2 million Bbls of crude oil storage, a combined 14 lanes of truck loading and unloading, and provides access to the Permian Express 2 transportation system.

- *Marcus Hook Industrial Complex*. The Marcus Hook Industrial Complex can receive crude oil via marine vessel and can deliver via marine vessel and pipeline. The terminal has a total active crude oil storage capacity of approximately 1 million Bbls.

- *Patoka, Illinois Terminal.* The Patoka, Illinois terminal is a tank farm and was contributed by ExxonMobil to the PEP joint venture and is located in Marion County, Illinois. The facility includes 234 acres of owned land and provides for approximately 2 million Bbls of crude oil storage.

Crude Oil Acquisition and Marketing

Our crude oil acquisition and marketing operations are conducted using our assets, which include approximately 370 crude oil transport trucks and approximately 150 crude oil truck unloading facilities, as well as third-party truck, rail and marine assets.

All Other

The following details our assets in the all other segment.

Equity Method Investments

- *Sunoco LP*. We have an equity method investment in limited partnership units of Sunoco LP. As of December 31, 2017, our investment consisted of 43.5 million units, representing 43.6% of Sunoco LP's total outstanding common units. Subsequent to Sunoco LP's repurchase of a portion of its common units on February 7, 2018, our investment consists of 26.2 million units, representing 31.8% of Sunoco LP's total outstanding common units.

- *PES*. We have a non-controlling interest in PES, comprising 33% of PES' outstanding common units. As discussed in "Segment Overview - All Other" above, PES Holdings and eight affiliates filed for Chapter 11 bankruptcy protection on January 21, 2018.

Contract Services Operations

We own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management. Our contract treating services are primarily located in Texas, Louisiana and Arkansas.

Compression

We own all of the outstanding equity interests of CDM, which operates a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas. As discussed in "Strategic Transactions," in January 2018, we entered into an agreement to contribute CDM to USAC.

We own 100% of the membership interests of ETG, which owns all of the partnership interests of ETT. ETT provides compression services to customers engaged in the transportation of natural gas, including our other segments.

Natural Resources Operations

Our Natural Resources operations primarily involve the management and leasing of coal properties and the subsequent collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage fees. As of December 31, 2017, we owned or controlled approximately 766 million tons of proven and probable coal reserves in central and northern Appalachia, properties in eastern Kentucky, southwestern Virginia and southern West Virginia, and in the Illinois Basin, properties in southern Illinois, Indiana, and western Kentucky and as the operator of end-user coal handling facilities.

Liquefaction Project

LCL, an entity whose parent is owned 60% by ETE and 40% by ETP, is in the process of developing a liquefaction project at the site of ETE's existing regasification facility in Lake Charles, Louisiana. The project development agreement previously entered into in September 2013 with BG Group plc (now "Shell") related to this project expired in February 2017. On June 28, 2017, LCL signed a memorandum of understanding with Korea Gas Corporation and Shell to study the feasibility of a joint development of the Lake Charles liquefaction project. The project would utilize existing dock and storage facilities owned by ETE located on the Lake Charles site. The parties' determination as to the feasibility of the project will be particularly dependent upon the prospects for securing long-term contractual arrangements for the off-take of LNG which in turn will be dependent upon supply and demand factors affecting the price of LNG in foreign markets. The financial viability of the project will also be dependent upon a number of other factors, including the expected cost to construct the liquefaction facility, the terms and conditions of the financing for the construction of the liquefaction facility, the cost of the natural gas supply, the costs to transport natural gas to the liquefaction facility, the costs to operate the liquefaction facility and the costs to transport LNG from the liquefaction facility to customers in foreign markets (particularly Europe and Asia). Some of these costs fluctuate based on a variety of factors, including supply and demand factors affecting the price of natural gas in the United States, supply and demand factors affecting the costs for construction services for large infrastructure projects in the United States, and general economic conditions, there can be no assurance that the parties will determine to proceed to develop this project.

The liquefaction project is expected to consist of three LNG trains with a combined design nameplate outlet capacity of 16.45 metric tonnes per annum. Once completed, the liquefaction project will enable LCL to liquefy domestically produced natural gas and export it as LNG. By adding the new liquefaction facility and integrating with the existing LNG regasification/import facility, the enhanced facility would become a bi-directional facility capable of exporting and importing LNG. Shell is the sole customer for the existing regasification facility and is obligated to pay reservation fees for 100% of the regasification capacity regardless of whether it actually utilizes such capacity pursuant to a regasification services agreement that terminates in 2030. The liquefaction project would be constructed on 440 acres of land, of which 80 acres are owned by Lake Charles LNG and the remaining acres are to be leased by LCL under a long-term lease from the Lake Charles Harbor and Terminal District.

The export of LNG produced by the liquefaction project from the United States would be undertaken under long-term export authorizations issued by the DOE to LCL. In March 2013, LCL obtained a DOE authorization to export LNG to countries with which the United States has or will have Free Trade Agreements ("FTA") for trade in natural gas (the "FTA Authorization"). In July 2016, LCL also obtained a conditional DOE authorization to export LNG to countries that do not have an FTA for trade in natural gas (the "Non-FTA Authorization"). The FTA Authorization and Non-FTA Authorization have 25- and 20-year terms, respectively.

We have received our wetlands permits from the United States Army Corps of Engineers ("USACE") to perform wetlands mitigation work and to perform modification and dredging work for the temporary and permanent dock facilities at the Lake Charles LNG facilities.

Business Strategy

We have designed our business strategy with the goal of creating and maximizing value to our Unitholders. We believe we have engaged, and will continue to engage, in a well-balanced plan for growth through strategic acquisitions, internally generated expansion, measures aimed at increasing the profitability of our existing assets and executing cost control measures where appropriate to manage our operations.

We intend to continue to operate as a diversified, growth-oriented master limited partnership with a focus on increasing the amount of cash available for distribution on each Common Unit. We believe that by pursuing independent operating and growth strategies we will be best positioned to achieve our objectives. We balance our desire for growth with our goal of preserving a strong balance sheet, ample liquidity and investment grade credit metrics.

Following is a summary of the business strategies of our core businesses:

Growth through acquisitions. We intend to continue to make strategic acquisitions that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of our existing assets while supporting our investment grade credit ratings.

Engage in construction and expansion opportunities. We intend to leverage our existing infrastructure and customer relationships by constructing and expanding systems to meet new or increased demand for midstream and transportation services.

Increase cash flow from fee-based businesses. We intend to increase the percentage of our business conducted with third parties under fee-based arrangements in order to provide for stable, consistent cash flows over long contract periods while reducing exposure to changes in commodity prices.

Enhance profitability of existing assets. We intend to increase the profitability of our existing asset base by adding new volumes under long-term producer commitments, undertaking additional initiatives to enhance utilization and reducing costs by improving operations.

Competition

Natural Gas

The business of providing natural gas gathering, compression, treating, transportation, storage and marketing services is highly competitive. Since pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our transportation and storage segment are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability.

We face competition with respect to retaining and obtaining significant natural gas supplies under terms favorable to us for the gathering, treating and marketing portions of our business. Our competitors include major integrated oil companies, interstate and intrastate pipelines and other companies that gather, compress, treat, process, transport and market natural gas. Many of our competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours.

In marketing natural gas, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil companies, and local and national natural gas gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly, and through affiliates, in marketing activities that compete with our marketing operations.

NGL

In markets served by our NGL pipelines, we face competition with other pipeline companies, including those affiliated with major oil, petrochemical and natural gas companies, and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees, reliability and quality of customer service. We face competition with other storage facilities based on fees charged and the ability to receive and distribute the customer's products. We compete with a number of NGL fractionators in Texas and Louisiana. Competition for such services is primarily based on the fractionation fee charged.

Crude Oil and Products

In markets served by our products and crude oil pipelines, we face competition from other pipelines as well as rail and truck transportation. Generally, pipelines are the lowest cost method for long-haul, overland movement of products and crude oil. Therefore, the most significant competitors for large volume shipments in the areas served by our pipelines are other pipelines.

In addition, pipeline operations face competition from rail and trucks that deliver products in a number of areas that our pipeline operations serve. While their costs may not be competitive for longer hauls or large volume shipments, rail and trucks compete effectively for incremental and marginal volume in many areas served by our pipelines.

With respect to competition from other pipelines, the primary competitive factors consist of transportation charges, access to crude oil supply and market demand. Competitive factors in crude oil purchasing and marketing include price and contract flexibility, quantity and quality of services, and accessibility to end markets.

Our refined product terminals compete with other independent terminals with respect to price, versatility and services provided. The competition primarily comes from integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

Credit Risk and Customers

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may, at times, require collateral under certain circumstances to mitigate credit risk as necessary. The Partnership also uses industry standard commercial agreements which allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, gas and electric utilities, midstream companies and independent power generators. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

Our natural gas transportation and midstream revenues are derived significantly from companies that engage in exploration and production activities. The discovery and development of new shale formations across the United States has created an abundance of natural gas and crude oil resulting in a negative impact on prices in recent years for natural gas and crude oil. As a result, some of our exploration and production customers have been adversely impacted; however, we are monitoring these customers and mitigating credit risk as necessary.

During the year ended December 31, 2017, none of our customers individually accounted for more than 10% of our consolidated revenues.

Regulation of Interstate Natural Gas Pipelines. The FERC has broad regulatory authority over the business and operations of interstate natural gas pipelines. Under the Natural Gas Act ("NGA"), the FERC generally regulates the transportation of natural gas in interstate commerce. For FERC regulatory purposes, "transportation" includes natural gas pipeline transmission (forwardhauls and backhauls), storage and other services. The Florida Gas Transmission, Transwestern, Panhandle Eastern, Trunkline Gas, Tiger, Fayetteville Express, Sea Robin, Gulf States and Midcontinent Express pipelines transport natural gas in interstate commerce and thus each qualifies as a "natural-gas company" under the NGA subject to the FERC's regulatory jurisdiction. We also hold certain natural gas storage facilities that are subject to the FERC's regulatory oversight under the NGA.

The FERC's NGA authority includes the power to:

- approve the siting, construction and operation of new facilities;
- review and approve transportation rates;
- determine the types of services our regulated assets are permitted to perform;
- regulate the terms and conditions associated with these services;
- permit the extension or abandonment of services and facilities;
- require the maintenance of accounts and records; and
- authorize the acquisition and disposition of facilities.

Under the NGA, interstate natural gas companies must charge rates that are just and reasonable. In addition, the NGA prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The maximum rates to be charged by NGA-jurisdictional natural gas companies and their terms and conditions for service are required to be on file with the FERC. Most natural gas companies are authorized to offer discounts from their FERC-approved maximum just and reasonable rates when competition warrants such discounts. Natural gas companies are also generally permitted to offer negotiated rates different from rates established in their tariff if, among other requirements, such companies' tariffs offer a cost-based recourse rate to a prospective shipper as an alternative to the negotiated rate. Natural gas companies must make offers of rate discounts and negotiated rates on a basis that is not unduly discriminatory. Existing tariff rates may be challenged by complaint or on the FERC's own motion, and if found unjust and unreasonable, may be altered on a prospective basis from no earlier than the date of the complaint or initiation of a proceeding by the FERC. The FERC must also approve all rate changes. We cannot guarantee that the FERC will allow us to charge rates that fully recover our costs or continue to pursue its approach of pro-competitive policies.

For two of our NGA-jurisdictional natural gas companies, Tiger and Fayetteville Express, the large majority of capacity in those pipelines is subscribed for lengthy terms under FERC-approved negotiated rates. However, as indicated above, cost-based recourse rates are also offered under their respective tariffs.

Pursuant to the FERC's rules promulgated under the Energy Policy Act of 2005, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction: (i) to defraud using any device, scheme or artifice; (ii) to make any untrue statement of material fact or omit a material fact; or (iii) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The Commodity Futures Trading Commission ("CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act ("CEA"). With regard to our physical purchases and sales of natural gas, NGLs or other energy commodities; our gathering or transportation of these energy commodities; and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess or seek civil penalties of up to approximately $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Failure to comply with the NGA, the Energy Policy Act of 2005, the CEA and the other federal laws and regulations governing our operations and business activities can result in the imposition of administrative, civil and criminal remedies.

Regulation of Intrastate Natural Gas and NGL Pipelines. Intrastate transportation of natural gas and NGLs is largely regulated by the state in which such transportation takes place. To the extent that our intrastate natural gas transportation systems transport natural gas in interstate commerce, the rates and terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"). The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. The rates and terms and conditions of some transportation and storage services provided on the Oasis pipeline, HPL System, East Texas pipeline, ET Fuel System, Trans-Pecos and Comanche Trail are subject to FERC regulation pursuant to Section 311 of the NGPA. Under Section 311, rates charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility's statement of operating conditions are also subject to FERC review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by the FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved statement of operating conditions could result in an alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies.

Our intrastate natural gas operations are also subject to regulation by various agencies in Texas, principally the TRRC. Our intrastate pipeline and storage operations in Texas are also subject to the Texas Utilities Code, as implemented by the TRRC. Generally, the TRRC is vested with authority to ensure that rates, operations and services of gas utilities, including intrastate pipelines, are just and reasonable and not discriminatory. The rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a customer or TRRC complaint. We cannot predict whether such a complaint will be filed against us or whether the TRRC will change its regulation of these rates. Failure to comply with the Texas Utilities Code can result in the imposition of administrative, civil and criminal remedies.

Our NGL pipelines and operations may also be or become subject to state public utility or related jurisdiction which could impose additional safety and operational regulations relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL gathering facilities. In addition, the rates, terms and conditions for shipments of NGLs on our pipelines are subject to regulation by FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 (the "EPAct of 1992") if the NGLs are transported in interstate or foreign commerce whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all NGLs shipped on our pipelines, FERC regulation could be triggered by our customers' transportation decisions.

Regulation of Sales of Natural Gas and NGLs. The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. The price at which we sell NGLs is not subject to federal or state regulation.

To the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to the use of such capacity. Any failure on our part to comply with the FERC's regulations and policies, or with an interstate pipeline's tariff, could result in the imposition of civil and criminal penalties.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of the FERC's regulatory changes may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action in a manner that is materially different from other natural gas marketers with whom we compete.

Regulation of Gathering Pipelines. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own a number of natural gas pipelines in Texas, Louisiana and West Virginia that we believe meet the traditional tests the FERC uses to establish a pipeline's status as a gathering pipeline not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation and varying interpretations, so the classification and regulation of our gathering facilities could be subject to change based on future determinations by the FERC, the courts and Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

In Texas, our gathering facilities are subject to regulation by the TRRC under the Texas Utilities Code in the same manner as described above for our intrastate pipeline facilities. Louisiana's Pipeline Operations Section of the Department of Natural Resources' Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities.

Historically, apart from pipeline safety, Louisiana has not acted to exercise this jurisdiction respecting gathering facilities. In Louisiana, our Chalkley System is regulated as an intrastate transporter, and the Louisiana Office of Conservation has determined that our Whiskey Bay System is a gathering system.

We are subject to state ratable take and common purchaser statutes in all of the states in which we operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting the right of an owner of gathering facilities to decide with whom it contracts to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. For example, the TRRC has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of their affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination allegations. Our gathering operations could be adversely affected should they be subject in the future to the application of additional or different state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any,

such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Regulation of Interstate Crude Oil, NGL and Products Pipelines. Interstate common carrier pipeline operations are subject to rate regulation by the FERC under the ICA, the EPAct of 1992, and related rules and orders. The ICA requires that tariff rates for petroleum pipelines be "just and reasonable" and not unduly discriminatory and that such rates and terms and conditions of service be filed with the FERC. This statute also permits interested persons to challenge proposed new or changed rates. The FERC is authorized to suspend the effectiveness of such rates for up to seven months, though rates are typically not suspended for the maximum allowable period. If the FERC finds that the new or changed rate is unlawful, it may require the carrier to pay refunds for the period that the rate was in effect. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

The FERC generally has not investigated interstate rates on its own initiative when those rates, like those we charge, have not been the subject of a protest or a complaint by a shipper. However, the FERC could investigate our rates at the urging of a third party if the third party is either a current shipper or has a substantial economic interest in the tariff rate level. Although no assurance can be given that the tariff rates charged by us ultimately will be upheld if challenged, management believes that the tariff rates now in effect for our pipelines are within the maximum rates allowed under current FERC policies and precedents.

For many locations served by our product and crude pipelines, we are able to establish negotiated rates. Otherwise, we are permitted to charge cost-based rates, or in many cases, grandfathered rates based on historical charges or settlements with our customers. To the extent we rely on cost-of-service ratemaking to establish or support our rates, the issue of the proper allowance for federal and state income taxes could arise. In 2005, FERC issued a policy statement stating that it would permit common carriers, among others, to include an income tax allowance in cost-of-service rates to reflect actual or potential tax liability attributable to a regulated entity's operating income, regardless of the form of ownership. Under FERC's policy, a tax pass-through entity seeking such an income tax allowance must establish that its partners or members have an actual or potential income tax liability on the regulated entity's income. Whether a pipeline's owners have such actual or potential income tax liability is subject to review by FERC on a case-by-case basis. Although this policy is generally favorable for common carriers that are organized as pass-through entities, it still entails rate risk due to the FERC's case-by-case review approach. The application of this policy, as well as any decision by FERC regarding our cost of service, may also be subject to review in the courts. In December 2016, FERC issued a Notice of Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs. FERC requested comments regarding how to address any double recovery resulting from the Commission's current income tax allowance and rate of return policies. The comment period with respect to the notice of inquiry ended on April 7, 2017. The outcome of the inquiry is still pending.

Effective January 2018, the 2017 Tax Cuts and Jobs Act changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. With the lower tax rate, the maximum tariff rates allowed by FERC under its rate base methodology for master limited partnerships may be impacted by a lower income tax allowance component. Many of our interstate pipelines, such as Tiger, MEP and FEP, have negotiated market rates that were agreed to by customers in connection with long-term contracts entered into to support the construction of the pipelines. Other systems, such as FGT, Transwestern and PEPL, have a mix of tariff rate, discount rate, and negotiated rate agreements. In addition, several of these pipelines are covered by approved settlements, where rate filings will be made in the future. As such, the timing and impact of these systems of any tax change is unknown at this time.

EPAct of 1992 required FERC to establish a simplified and generally applicable methodology to adjust tariff rates for inflation for interstate petroleum pipelines. As a result, FERC adopted an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index for Finished Goods, or PPIFG. FERC's indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2011 and ending June 30, 2016, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPIFG plus 2.65%. Beginning July 1, 2016, the indexing method provided for annual changes equal to the change in PPIFG plus 1.23%. The indexing methodology is applicable to existing rates, including grandfathered rates, with the exclusion of market-based rates. A pipeline is not required to raise its rates up to the index ceiling, but it is permitted to do so and rate increases made under the index are presumed to be just and reasonable unless a protesting party can demonstrate that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. Under the indexing rate methodology, in any year in which the index is negative, pipelines must file to lower their rates if those rates would otherwise be above the rate ceiling. In October 2016, FERC issued an Advance Notice of Proposed Rulemaking seeking comment on a number of proposals, including: (1) whether the Commission should deny any increase in a rate ceiling or annual index-based rate increase if a pipeline's revenues exceed total costs by 15% for the prior two years; (2) a new percentage comparison test that would deny a proposed increase to a pipeline's rate or ceiling level greater than 5% above the barrel-mile cost changes; and (3) a requirement that all pipelines file indexed ceiling levels annually, with the ceiling levels subject to challenge

and restricting the pipeline's ability to carry forward the full indexed increase to a future period. The comment period with respect to the proposed rules ended on March 17, 2017. FERC has taken no further action on the proposed rule to date.

Finally, in November 2017 FERC responded to a petition for declaratory order and issued an order that may have significant impacts on the way a marketer of crude oil or petroleum products that is affiliated with an interstate pipeline can price its services if those services include transportation on an affiliate's interstate pipeline. In particular, FERC's November 2017 order prohibits buy/sell arrangements by a marketing affiliate if: (i) the transportation differential applicable to its affiliate's interstate pipeline transportation service is at a discount to the affiliated pipeline's filed rate for that service; and (ii) the pipeline affiliate subsidizes the loss. Several parties have requested that FERC clarify its November 2017 order or, in the alternative, grant rehearing of the November 2017 order. We are unable to predict how FERC will respond to such requests. Depending on how FERC responds, it could have an impact on the rates we are permitted to charge.

Regulation of Intrastate Crude Oil, NGL and Products Pipelines. Some of our crude oil, NGL and products pipelines are subject to regulation by the TRRC, the PA PUC, and the Oklahoma Corporation Commission. The operations of our joint venture interests are also subject to regulation in the states in which they operate. The applicable state statutes require that pipeline rates be nondiscriminatory and provide no more than a fair return on the aggregate value of the pipeline property used to render services. State commissions generally have not initiated an investigation of rates or practices of petroleum pipelines in the absence of shipper complaints. Complaints to state agencies have been infrequent and are usually resolved informally. Although management cannot be certain that our intrastate rates ultimately would be upheld if challenged, we believe that, given this history, the tariffs now in effect are not likely to be challenged or, if challenged, are not likely to be ordered to be reduced.

In addition, as noted above, the rates, terms and conditions for shipments of crude oil, NGLs or products on our pipelines could be subject to regulation by FERC under the ICA and the EPAct of 1992 if the crude oil, NGLs or products are transported in interstate or foreign commerce whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all crude oil, NGLs or products shipped on our pipelines, FERC regulation could be triggered by our customers' transportation decisions.

Regulation of Pipeline Safety. Our pipeline operations are subject to regulation by the DOT, through the PHMSA, pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect high consequence areas ("HCAs"), which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. Failure to comply with the pipeline safety laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the occurrence of delays in permitting or the performance of projects, or the issuance of injunctions limiting or prohibiting some or all of our operations in the affected area.

The HLPSA and NGPSA have been amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act") and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("2016 Pipeline Safety Act"). The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. The 2011 Pipeline Safety Act doubled the maximum administrative fines for safety violations from $100,000 to $200,000 for a single violation and from $1 million to $2 million for a related series of violations, but provided that these maximum penalty caps do not apply to certain civil enforcement actions. Effective April 27, 2017, to account for inflation, those maximum civil penalties were increased to $209,002 per day, with a maximum of $2,090,022 for a series of violations. The 2016 Pipeline Safety Act extended PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and developing new safety standards for natural gas storage facilities by June 22, 2018. The 2016 Pipeline Safety Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of hazardous liquid or natural gas pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. The states in which we conduct operations typically have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines. Under such state regulatory programs, states have the authority to conduct pipeline inspections, to investigate accidents and to oversee compliance and enforcement, safety programs and record maintenance and reporting. Congress, PHMSA and individual states may pass or implement additional safety requirements that could result in increased compliance costs for us and other companies in our industry. For example, federal construction, maintenance and inspection standards under the NGPSA that apply to pipelines in relatively populated areas may not apply to gathering lines running through rural regions. This "rural gathering exemption" under the NGPSA presently exempts substantial portions of our gathering facilities located outside of cities, towns or any area designated as residential or commercial from jurisdiction under the NGPSA, but does not apply to our intrastate natural gas pipelines. In recent years, the PHMSA has considered changes to this rural gathering exemption, including publishing an advance notice of proposed rulemaking relating to gas pipelines in 2011, in which the agency sought public comment on possible changes to the definition of "high consequence areas" and "gathering lines" and the strengthening of pipeline integrity management requirements. In April 2016, pursuant to one of the requirements of the 2011 Pipeline Safety Act, PHMSA published a proposed rulemaking that, among other things, would expand certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined "moderate consequence areas" that contain as few as 5 dwellings within a potential impact area; require natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures ("MAOP"); and require certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements for natural gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has not yet finalized the March 2016 proposed rulemaking.

In January 2017, PHMSA issued a final rule amending federal safety standards for hazardous liquid pipelines. The final rule is the latest step in a lengthy rulemaking process that began in 2010 with a request for comments and continued with publication of a rulemaking proposal in October 2015. The general effective date of this final rule is six months from publication in the Federal Register, but it is currently subject to further administrative review in connection with the transition of Presidential administrations and thus, implementation of this final rule remains uncertain. The final rule addresses several areas including reporting requirements for gravity and unregulated gathering lines, inspections after weather or climatic events, leak detection system requirements, revisions to repair criteria and other integrity management revisions. In addition, PHMSA issued regulations on January 23, 2017, on operator qualification, cost recovery, accident and incident notification and other pipeline safety changes that are now effective. These regulations are also subject, however, to potential further review in connection with the transition of Presidential administrations. Historically, our pipeline safety costs have not had a material adverse effect on our business or results of operations but there is no assurance that such costs will not be material in the future, whether due to elimination of the rural gathering exemption or otherwise due to changes in pipeline safety laws and regulations.

In another example of how future legal requirements could result in increased compliance costs, notwithstanding the applicability of the federal OSHA's Process Safety Management ("PSM") regulations and the EPA's Risk Management Planning ("RMP") requirements at regulated facilities, PHMSA and one or more state regulators, including the Texas Railroad Commission, have in recent years, expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, in order to assess compliance of such equipment and pipelines with hazardous liquid pipeline safety requirements. To the extent that these actions are pursued by PHMSA, midstream operators of NGL fractionation facilities and associated storage facilities subject to such inspection may be required to make operational changes or modifications at their facilities to meet standards beyond current PSM and RMP requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

Environmental Matters

General. Our operation of processing plants, pipelines and associated facilities, including compression, in connection with the gathering, processing, storage and transmission of natural gas and the storage and transportation of NGLs, crude oil and refined products is subject to stringent federal, tribal, state and local laws and regulations, including those governing, among other things, air emissions, wastewater discharges, the use, management and disposal of hazardous and nonhazardous materials and wastes, and the cleanup of contamination. Noncompliance with such laws and regulations, or incidents resulting in environmental releases, could cause us to incur substantial costs, penalties, fines and criminal sanctions, third-party claims for personal injury or property damage, capital expenditures to retrofit or upgrade our facilities and programs, or curtailment or cancellation of permits on operations. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall cost of doing business, including our cost of planning, permitting, constructing and operating our plants, pipelines and other facilities. As a result of these laws and regulations, our construction and operation costs include capital, operating and maintenance cost items necessary to maintain or upgrade our equipment and facilities.

We have implemented procedures designed to ensure that governmental environmental approvals for both existing operations and those under construction are updated as circumstances require. Historically, our environmental compliance costs have not had a material adverse effect on our business, results of operations or financial condition; however, there can be no assurance that such costs will not be material in the future. For example, we cannot be certain, however, that identification of presently unidentified conditions, more rigorous enforcement by regulatory agencies, enactment of more stringent environmental laws and regulations or unanticipated events will not arise in the future and give rise to environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations.

Hazardous Substances and Waste Materials. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances and waste materials into soils, groundwater and surface water and include measures to prevent, minimize or remediate contamination of the environment. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of hazardous substances and waste materials and may require investigatory and remedial actions at sites where such material has been released or disposed. For example, the Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a "hazardous substance" into the environment. These persons include the owner and operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substance that has been released into the environment. Under CERCLA, these persons may be subject to strict, joint and several liability, without regard to fault, for, among other things, the costs of investigating and remediating the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and comparable state law also authorize the federal EPA, its state counterparts, and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Although "petroleum" as well as natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of our ordinary operations we generate wastes that may fall within that definition or that may be subject to other waste disposal laws and regulations. We may be responsible under CERCLA or state laws for all or part of the costs required to clean up sites at which such substances or wastes have been disposed.

We also generate both hazardous and nonhazardous wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, as amended, ("RCRA") and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA hazardous waste requirements at many of our facilities because the minimal quantities of hazardous wastes generated there make us subject to less stringent non-hazardous management standards. From time to time, the EPA has considered or third parties have petitioned the agency on the adoption of stricter handling, storage and disposal standards for nonhazardous wastes, including certain wastes associated with the exploration, development and production of crude oil and natural gas. For example, following the filing of a lawsuit by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the United States District Court for the District of Columbia on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. It is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements, or that the full complement of RCRA standards could be applied to facilities that generate lesser amounts of hazardous waste. Changes such as these examples in applicable regulations may result in a material increase in our capital expenditures or plant operating and maintenance expense and, in the case of our oil and natural gas exploration and production customers, could result in increased operating costs for those customers and a corresponding decrease in demand for our processing, transportation and storage services.

We currently own or lease sites that have been used over the years by prior owners and lessees and by us for various activities related to gathering, processing, storage and transmission of natural gas, NGLs, crude oil and products. Waste disposal practices within the oil and gas industry have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and wastes have been disposed of or otherwise released on or under various sites during the operating history of those facilities that are now owned or leased by us. Notwithstanding the possibility that these releases may have occurred during the ownership or operation of these assets by others, these sites may be subject to CERCLA, RCRA and comparable state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or contamination (including soil and groundwater contamination) or to prevent the migration of contamination.

As of December 31, 2017 and 2016, accruals of $350 million and $309 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover estimated material environmental liabilities including, for example, certain matters assumed in connection with our acquisition of the HPL System, our acquisition of Transwestern, potential environmental liabilities for three sites that were formerly owned by Titan Energy Partners, L.P. or its predecessors, and the predecessor owner's share of certain environmental liabilities of ETC OLP.

The Partnership is subject to extensive and frequently changing federal, tribal, state and local laws and regulations, including those relating to the discharge of materials into the environment or that otherwise relate to the protection of the environment, waste management and the characteristics and composition of fuels. These laws and regulations require environmental assessment and remediation efforts at many of Sunoco, Inc.'s facilities and at formerly owned or third-party sites. Accruals for these environmental remediation activities amounted to $284 million and $289 million at December 31, 2017 and 2016, respectively, which is included in the total accruals above. These legacy sites that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that are no longer operated by Sunoco, Inc., closed and/or sold refineries and other formerly owned sites. In December 2013, a wholly-owned captive insurance company was established for these legacy sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company. As of December 31, 2017 the captive insurance company held $207 million of cash and investments.

The Partnership's accrual for environmental remediation activities reflects anticipated work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. The accrual for known claims is undiscounted and is based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. It is often extremely difficult to develop reasonable estimates of future site remediation costs due to changing regulations, changing technologies and their associated costs, and changes in the economic environment. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated accruals for environmental remediation activities.

Under various environmental laws, including the RCRA, the Partnership has initiated corrective remedial action at certain of its facilities, formerly owned facilities and at certain third-party sites. At the Partnership's major manufacturing facilities, we have typically assumed continued industrial use and a containment/remediation strategy focused on eliminating unacceptable risks to human health or the environment. The remediation accruals for these sites reflect that strategy. Accruals include amounts designed to prevent or mitigate off-site migration and to contain the impact on the facility property, as well as to address known, discrete areas requiring remediation within the plants. Remedial activities include, for example, closure of RCRA waste management units, recovery of hydrocarbons, handling of impacted soil, mitigation of surface water impacts and prevention or mitigation of off-site migration. A change in this approach as a result of changing the intended use of a property or a sale to a third party could result in a comparatively higher cost remediation strategy in the future.

In general, a remediation site or issue is typically evaluated on an individual basis based upon information available for the site or issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (for example, service station sites) in determining the amount of probable loss accrual to be recorded. The estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance allows us the minimum amount of the range to accrue. Accordingly, the low end of the range often represents the amount of loss which has been recorded.

In addition to the probable and estimable losses which have been recorded, management believes it is reasonably possible (that is, it is less than probable but greater than remote) that additional environmental remediation losses will be incurred. At December 31, 2017, the aggregate of such additional estimated maximum reasonably possible losses, which relate to numerous individual sites, totaled approximately $5 million, which amount is in excess of the $350 million in environmental accruals recorded on December 31, 2017. This estimate of reasonably possible losses comprises estimates for remediation activities at current logistics and retail assets, and in many cases, reflects the upper end of the loss ranges which are described above. Such estimates include potentially higher contractor costs for expected remediation activities, the potential need to use more costly or comprehensive remediation methods and longer operating and monitoring periods, among other things.

In summary, total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of the Partnership's liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur,

would likely extend over many years, but management can provide no assurance that it would be over many years. If changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could materially and adversely impact multiple facilities, formerly owned facilities and third-party sites at the same time. As a result, from time to time, significant charges against income for environmental remediation may occur. And while management does not believe that any such charges would have a material adverse impact on the Partnership's consolidated financial position, it can provide no assurance.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by PCBs, and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2025 is $5 million, which is included in the total environmental accruals mentioned above. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCB contamination. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. Such future costs are not expected to have a material impact on our financial position, results of operations or cash flows, but management can provide no assurance.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, such as our processing plants and compression facilities, expected to produce air emissions or to result in the increase of existing air emissions, that we obtain and strictly comply with air permits containing various emissions and operational limitations, or that we utilize specific emission control technologies to limit emissions. We will incur capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. In addition, our processing plants, pipelines and compression facilities are subject to increasingly stringent regulations, including regulations that require the installation of control technology or the implementation of work practices to control hazardous air pollutants. Moreover, the Clean Air Act requires an operating permit for major sources of emissions and this requirement applies to some of our facilities. Historically, our costs for compliance with existing Clean Air Act and comparable state law requirements have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future. The EPA and state agencies are often considering, proposing or finalizing new regulations that could impact our existing operations and the costs and timing of new infrastructure development. For example, in October 2015, the EPA published a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the United States counties as either "attainment/unclassifiable" or "unclassifiable" and is expected to issue non-attainment designations for the remaining areas of the United States not addressed under the November 2017 final rule in the first half of 2018. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to our customers' operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended, ("Clean Water Act") and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including hydrocarbon-bearing wastes, into state waters and waters of the United States. Pursuant to the Clean Water Act and similar state laws, a National Pollutant Discharge Elimination System, or state permit, or both, must be obtained to discharge pollutants into federal and state waters. In addition, the Clean Water Act and comparable state laws require that individual permits or coverage under general permits be obtained by subject facilities for discharges of storm water runoff. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In May 2015, the EPA issued a final rule that attempts to clarify the federal jurisdictional reach over waters of the United States but this rule has been stayed nationwide by the United States Sixth Circuit Court of Appeals as that appellate court and numerous district courts ponder lawsuits opposing implementation of the rule. In June 2015, the EPA and the United States Army Corps of Engineers (the "Corps") published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States, but legal challenges to this rule followed. The 2015 rule was stayed nationwide to determine whether federal district or appellate courts had jurisdiction to hear cases in the matter and, in January 2017, the United States Supreme Court agreed to hear the case. The EPA and Corps proposed a rulemaking in June 2017 to repeal the June 2015 rule, announced their intent to issue a new rule defining the Clean Water Act's jurisdiction, and published a proposed rule in November 2017 specifying that the contested May 2015 rule would not take effect until two years after the November 2017 proposed rule was finalized and published in the Federal Register. Recently, on January 22, 2018, the

United States Supreme Court issued a decision finding that jurisdiction resides with the federal district courts; consequently, while implementation of the 2015 rule currently remains stayed, the previously-filed district court cases will be allowed to proceed. On January 31, 2018, the EPA and Corps finalized a rule that would delay applicability of the rule to two years from the rule's publication in the Federal Register. As a result of these recent developments, future implementation of the June 2015 rule is uncertain at this time but to the extent any rule expands the scope of the Clean Water Act's jurisdiction, our operations as well as our exploration and production customers' drilling programs could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

Spills. Our operations can result in the discharge of regulated substances, including NGLs, crude oil or other products. The Clean Water Act, as amended by the federal Oil Pollution Act of 1990, as amended, ("OPA"), and comparable state laws impose restrictions and strict controls regarding the discharge of regulated substances into state waters or waters of the United States. The Clean Water Act and comparable state laws can impose substantial administrative, civil and criminal penalties for non-compliance including spills and other non-authorized discharges. The OPA subjects owners of covered facilities to strict joint and potentially unlimited liability for removal costs and other consequences of a release of oil, where the release is into navigable waters, along shorelines or in the exclusive economic zone of the United States. Spill prevention control and countermeasure requirements of the Clean Water Act and some state laws require that containment dikes and similar structures be installed to help prevent the impact on navigable waters in the event of a release of oil. The PHMSA, the EPA, or various state regulatory agencies, has approved our oil spill emergency response plans that are to be used in the event of a spill incident.

In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Our management believes that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our results of operations, financial position or expected cash flows.

Endangered Species Act. The Endangered Species Act, as amended, restricts activities that may affect endangered or threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may operate in areas that are currently designated as a habitat for endangered or threatened species or where the discovery of previously unidentified endangered species, or the designation of additional species as endangered or threatened may occur in which event such one or more developments could cause us to incur additional costs, to develop habitat conservation plans, to become subject to expansion or operating restrictions, or bans in the affected areas. Moreover, such designation of previously unprotected species as threatened or endangered in areas where our oil and natural gas exploration and production customers operate could cause our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our services.

Climate Change. Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted rules under authority of the Clean Air Act that, among other things, establish Potential for Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore processing, transmission, storage and distribution facilities. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, the Subpart OOOOa standards have been subject to attempts by the EPA to stay portions of those standards, and the agency proposed rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of Subpart OOOOa in its entirety. The EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. This rule, should it remain in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France preparing an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. In August 2017, the United States State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. Finally, some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on our assets.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or rising waters, or increased costs for insurance. Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our NGLs and natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term "global warming" as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our products could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

Employee Health and Safety. We are subject to the requirements of the federal OSHA and comparable state laws that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration's hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. Historically, our costs for OSHA required activities, including general industry standards, recordkeeping requirements, and monitoring of occupational exposure to regulated substances, have not had a material adverse effect on our results of operations but there is no assurance that such costs will not be material in the future.

Employees

As of December 31, 2017, we employed 8,494 persons, 1,225 of which are represented by labor unions. We believe that our relations with our employees are satisfactory.

SEC Reporting

We file or furnish annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any related amendments and supplements thereto with the SEC. From time to time, we may also file registration and related statements pertaining to equity or debt offerings. You may read and copy any materials we file or furnish with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-732-0330. In addition, the SEC maintains an Internet website at http://www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

We provide electronic access, free of charge, to our periodic and current reports, and amendments to these reports, on our internet website located at http://www.energytransfer.com. These reports are available on our website as soon as reasonably practicable after we electronically file such materials with the SEC. Information contained on our website is not part of this report.

ITEM 1A. RISK FACTORS

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our structure as a limited partnership, our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering an investment in our securities. Panhandle files Annual Reports on Form 10-K that include risk factors that can be reviewed for further information. The risk factors set forth below, and those included in Panhandle's Annual Report on Form 10-K, are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Risks Inherent in an Investment in Us

Cash distributions are not guaranteed and may fluctuate with our performance and other external factors.

The amount of cash we can distribute to holders of our Common Units or other partnership securities depends upon the amount of cash we generate from our operations. The amount of cash we generate from our operations will fluctuate from quarter to quarter and will depend upon, among other things:

- the amount of natural gas, NGLs, crude oil and refined products transported in our pipelines and gathering systems;
- the level of throughput in our processing and treating operations;
- the fees we charge and the margins we realize for our services;
- the price of natural gas, NGLs, crude oil and refined products;
- the relationship between natural gas, NGL and crude oil prices;
- the amount of cash distributions we receive with respect to the Sunoco LP common units that our subsidiaries own;
- the weather in our operating areas;
- the level of competition from other midstream, transportation and storage and other energy providers;
- the level of our operating costs;
- prevailing economic conditions; and
- the level and results of our derivative activities.

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

- the level of capital expenditures we make;
- the level of costs related to litigation and regulatory compliance matters;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to borrow under our revolving credit facility;
- our ability to access capital markets;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our General Partner in its discretion for the proper conduct of our business.

Because of all these factors, we cannot guarantee that we will have sufficient available cash to pay a specific level of cash distributions to our Unitholders.

Furthermore, Unitholders should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow and is not solely a function of profitability, which is affected by non-cash items. As a result, we may declare and/or pay cash distributions during periods when we record net losses.

We may sell additional limited partner interests or other classes of equity, diluting existing interests of Unitholders.

Our partnership agreement allows us to issue an unlimited number of additional limited partner interests, including securities senior to the Common Units, without the approval of our Unitholders. The issuance of additional Common Units or other equity securities will have the following effects:

- the current proportionate ownership interest of our Unitholders in us will decrease;
- the amount of cash available for distribution on each Common Unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding Common Unit may be diminished; and
- the market price of the Common Units or partnership securities may decline.

Sunoco LP may issue additional common units, which may increase the risk that Sunoco LP will not have sufficient available cash to maintain or increase its per unit distribution level.

Sunoco LP's partnership agreement allows the issuance of an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by Sunoco LP will have the following effects:

- Unitholders' current proportionate ownership interest in Sunoco LP will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of Sunoco LP common units may decline.

The payment of distributions on any additional units issued by Sunoco LP may increase the risk that it may not have sufficient cash available to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to meet our obligations.

Future sales of our units or other limited partner interests in the public market could reduce the market price of Unitholders' limited partner interests.

As of January 31, 2018, ETE owned 27.5 million ETP Common Units. If ETE were to sell and/or distribute its Common Units to the holders of its equity interests in the future, those holders may dispose of some or all of these units. The sale or disposition of a substantial portion of these units in the public markets could reduce the market price of our outstanding Common Units.

Unitholders may not have limited liability if a court finds that Unitholder actions constitute control of our business.

Under Delaware law, a Unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of Unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

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

Our debt level and debt agreements may limit our ability to make distributions to Unitholders and may limit our future financial and operating flexibility.

As of December 31, 2017, we had approximately $33.09 billion of consolidated debt, excluding the debt of our joint ventures. Our level of indebtedness affects our operations in several ways, including, among other things:

- a significant portion of our and our subsidiaries' cash flow from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes, including payment of distributions;
- covenants contained in our and our subsidiaries' existing debt agreements require us and them, as applicable, to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;

- our and our subsidiaries' ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership, corporate or limited liability company purposes, as applicable, may be limited;
- we may be at a competitive disadvantage relative to similar companies that have less debt;
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level; and
- failure by us or our subsidiaries to comply with the various restrictive covenants of our respective debt agreements could negatively impact our ability to incur additional debt, including our ability to utilize the available capacity under our revolving credit facility, and our ability to pay our distributions.

Capital projects will require significant amounts of debt and equity financing, which may not be available to us on acceptable terms, or at all.

We plan to fund our growth capital expenditures, including any new pipeline construction projects and improvements or repairs to existing facilities that we may undertake, with proceeds from sales of our debt and equity securities and borrowings under our revolving credit facility; however, we cannot be certain that we will be able to issue our debt and equity securities on terms satisfactory to us, or at all. If we are unable to finance our expansion projects as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our expansion plans.

A significant increase in our indebtedness that is proportionately greater than our issuance of equity could negatively impact our and our subsidiaries' credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Increases in interest rates could adversely affect our business, results of operations, cash flows and financial condition.

In addition to our exposure to commodity prices, we have exposure to changes in interest rates. Approximately $5.11 billion of our consolidated debt as of December 31, 2017 bears interest at variable interest rates and the remainder bears interest at fixed rates. To the extent that we have debt with floating interest rates, our results of operations, cash flows and financial condition could be materially adversely affected by increases in interest rates. We manage a portion of our interest rate exposures by utilizing interest rate swaps.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our Common Units. Any such reduction in demand for our Common Units resulting from other more attractive investment opportunities may cause the trading price of our Common Units to decline.

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of our General Partner, and of ETE as the indirect owner of our General Partner, may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of our General Partner and ETE over our business activities, including our cash distributions, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our General Partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the Partnership to service their indebtedness.

ETE has significant indebtedness outstanding and is dependent principally on the cash distributions from its general and limited partner equity interests in us to service such indebtedness. Any distributions by us to ETE will be made only after satisfying our then current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us, ETP GP and ETP LLC from the entities that control ETP GP (ETE and its general partner), our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of such entities were viewed as substantially lower or riskier than ours.

Unitholders have limited voting rights and are not entitled to elect the General Partner or its directors. In addition, even if Unitholders are dissatisfied, they cannot easily remove the General Partner.

Unlike the holders of common stock in a corporation, Unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our General Partner and will have no right to elect our General Partner on an annual or other continuing basis. Although our General Partner has a contractually-limited fiduciary duty to our Unitholders, the directors of our General Partner and its general partner have a fiduciary duty to manage the General Partner and its general partner in a manner beneficial to the owners of those entities.

Furthermore, if the Unitholders are dissatisfied with the performance of our General Partner, they may be unable to remove our General Partner. The General Partner generally may not be removed except upon the vote of the holders of 66 2/3% of the outstanding units voting together as a single class, including units owned by the General Partner and its affiliates. As of December 31, 2017,

ETE and its affiliates held approximately 2.4% of our outstanding Common Units and our officers and directors held less than 1% of our outstanding Common Units.

Furthermore, Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than the General Partner and its affiliates, cannot be voted on any matter.

Our General Partner may, in its sole discretion, approve the issuance of partnership securities and specify the terms of such partnership securities.

Pursuant to our partnership agreement, our General Partner has the ability, in its sole discretion and without the approval of the Unitholders, to approve the issuance of securities by the Partnership at any time and to specify the terms and conditions of such securities. The securities authorized to be issued may be issued in one or more classes or series, with such designations, preferences, rights, powers and duties (which may be senior to existing classes and series of partnership securities), as shall be determined by our General Partner, including:

- the right to share in the Partnership's profits and losses;
- the right to share in the Partnership's distributions;
- the rights upon dissolution and liquidation of the Partnership;
- whether, and the terms upon which, the Partnership may redeem the securities;
- whether the securities will be issued, evidenced by certificates and assigned or transferred; and
- the right, if any, of the security to vote on matters relating to the Partnership, including matters relating to the relative rights, preferences and privileges of such security.

Please see "We may sell additional limited partner interests, diluting existing interests of Unitholders." above.

The control of our General Partner may be transferred to a third party without Unitholder consent.

The General Partner may transfer its general partner interest to a third party without the consent of the Unitholders. Furthermore, the general partner of our General Partner may transfer its general partner interest in our General Partner to a third party without the consent of the Unitholders. Any new owner of the General Partner or the general partner of the General Partner would be in a position to replace the officers of the General Partner with its own choices and to control the decisions taken by such officers.

Unitholders may be required to sell their units to the General Partner at an undesirable time or price.

If at any time less than 20% of the outstanding units of any class are held by persons other than the General Partner and its affiliates, the General Partner will have the right to acquire all, but not less than all, of those units at a price no less than their then-current market price. As a consequence, a Unitholder may be required to sell their Common Units at an undesirable time or price. The General Partner may assign this purchase right to any of its affiliates or to us.

The interruption of distributions to us from our operating subsidiaries and equity investees may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a holding company with no business operations other than that of our operating subsidiaries. Our only significant assets are the equity interests we own in our operating subsidiaries and equity investees. As a result, we depend upon the earnings and cash flow of our operating subsidiaries and equity investees and any interruption of distributions to us may affect our ability to meet our obligations, including any obligations under our debt agreements, and to make distributions to our partners.

Cost reimbursements due to our General Partner may be substantial and may reduce our ability to pay the distributions to Unitholders.

Prior to making any distributions to our Unitholders, we will reimburse our General Partner for all expenses it has incurred on our behalf. In addition, our General Partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by the General Partner. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to the Unitholders. Our General Partner has sole discretion to determine the amount of these expenses and fees.

Unitholders may have liability to repay distributions.

Under certain circumstances, Unitholders may have to repay us amounts wrongfully distributed to them. Under Delaware law, we may not make a distribution to Unitholders if the distribution causes our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and non-recourse liabilities are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that a limited partner who receives such a distribution and knew at the time of the distribution that the distribution violated Delaware law, will be liable to the limited partnership for the distribution amount for three years from the distribution date. Under Delaware law, an assignee who becomes a substituted limited partner of a limited partnership is liable for the obligations of the assignor to make contributions to the partnership. However, such an assignee is not obligated for liabilities unknown to him at the time he or she became a limited partner if the liabilities could not be determined from the partnership agreement.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than the partnership interests and the equity in our subsidiaries. As a result, our ability to pay distributions to our Unitholders and to service our debt depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. If we are unable to obtain funds from our subsidiaries we may not be able to pay distributions to our Unitholders or to pay interest or principal on our debt when due.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service our debt or to repay debt at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our Available Cash (as defined in our partnership agreement) to our Unitholders of record and our General Partner. Available Cash is generally all of our cash on hand as of the end of a quarter, adjusted for cash distributions and net changes to reserves. Our General Partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating subsidiaries in amounts it determines in its reasonable discretion to be necessary or appropriate:

- to provide for the proper conduct of our business and the businesses of our operating subsidiaries (including reserves for future capital expenditures and for our anticipated future credit needs);
- to provide funds for distributions to our Unitholders and our General Partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.

A downgrade of our credit ratings could impact our and our subsidiaries' liquidity, access to capital and costs of doing business, and maintaining credit ratings is under the control of independent third parties.

A downgrade of our credit ratings might increase our and our subsidiaries' cost of borrowing and could require us to post collateral with third parties, negatively impacting our available liquidity. Our and our subsidiaries' ability to access capital markets could also be limited by a downgrade of our credit ratings and other disruptions. Such disruptions could include:

- economic downturns;
- deteriorating capital market conditions;
- declining market prices for natural gas, NGLs and other commodities;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies; and
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.

Risks Related to Conflicts of Interest

Our partnership agreement limits our General Partner's fiduciary duties to our Unitholders and restricts the remedies available to Unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our General Partner and its affiliates and reduce the obligations to which our General Partner would otherwise be held by state-law fiduciary duty standards. The following is a summary of the material restrictions contained in our partnership agreement on the duties owed by our General Partner, and our officers and directors, to the limited partners. Our partnership agreement:

- eliminates all standards of care and duties other than those set forth in our partnership agreement, including fiduciary duties, to the fullest extent permitted by law;
- permits our General Partner to make a number of decisions in its "sole discretion," which standard entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our General Partner is entitled to make other decisions in its "reasonable discretion;"
- generally provides that affiliated transactions and resolutions of conflicts of interest must be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our General Partner may consider the interests of all parties involved, including its own;
- provides that unless our General Partner has acted in bad faith, the action taken by our General Partner shall not constitute a breach of its fiduciary duty;
- provides that our General Partner may resolve any conflicts of interest involving us and our General Partner and its affiliates, and any resolution of a conflict of interest by our General Partner that is "fair and reasonable" to us will be deemed approved by all partners, including the Unitholders, and will not constitute a breach of the partnership agreement;
- provides that our General Partner may, but is not required, in connection with its resolution of a conflict of interest, to seek "special approval" of such resolution by appointing a conflicts committee of the General Partner's board of directors composed of two or more independent directors to consider such conflicts of interest and to recommend action to the board of directors, and any resolution of the conflict of interest by the conflicts committee shall be conclusively deemed "fair and reasonable" to us;
- provides that our General Partner may consult with consultants and advisors and, subject to certain restrictions, is conclusively deemed to have acted in good faith when it acts in reliance on the opinion of such consultants and advisors; and
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our General Partner and those other persons acted in good faith.

In order to become a limited partner of our partnership, a Unitholder is required to agree to be bound by the provisions in our partnership agreement, including the provisions discussed above.

Some of our executive officers and directors face potential conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of ETE. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our Unitholders' best interests. In addition, these overlapping executive officers and directors allocate their time among us and ETE. These officers and directors face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

The General Partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our Unitholders.

Our partnership agreement requires the General Partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, our partnership agreement permits the General Partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to Unitholders.

Our General Partner has conflicts of interest and limited fiduciary responsibilities that may permit our General Partner to favor its own interests to the detriment of Unitholders.

ETE indirectly owns our General Partner and as a result controls us. The directors and officers of our General Partner and its affiliates have fiduciary duties to manage our General Partner in a manner that is beneficial to ETE, the sole owner of our General Partner. At the same time, our General Partner has contractually-limited fiduciary duties to our Unitholders. Therefore, our General Partner's duties to us may conflict with the duties of its officers and directors to ETE as its sole owner. As a result of these conflicts of interest, our General Partner may favor its own interest or those of ETE or their owners or affiliates over the interest of our Unitholders.

Such conflicts may arise from, among others, the following:

- Our partnership agreement limits the liability and reduces the fiduciary duties of our General Partner while also restricting the remedies available to our Unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. Unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law. Our General Partner is allowed to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duties to us.
- Our General Partner is allowed to take into account the interests of parties in addition to us, including ETE, in resolving conflicts of interest, thereby limiting its fiduciary duties to us.
- Our General Partner's affiliates, including ETE, are not prohibited from engaging in other businesses or activities, including those in direct competition with us.
- Our General Partner determines the amount and timing of our asset purchases and sales, capital expenditures, borrowings, repayments of debt, issuances of equity and debt securities and cash reserves, each of which can affect the amount of cash that is distributed to Unitholders and to ETE.
- Neither our partnership agreement nor any other agreement requires ETE or its affiliates to pursue a business strategy that favors us. The directors and officers of the general partners of ETE have a fiduciary duty to make decisions in the best interest of their members, limited partners and Unitholders, which may be contrary to our best interests.
- Some of the directors and officers of ETE who provide advice to us also may devote significant time to the businesses of ETE and will be compensated by them for their services.
- Our General Partner determines which costs, including allocated overhead costs, are reimbursable by us.
- Our General Partner is allowed to resolve any conflicts of interest involving us and our General Partner and its affiliates, and any resolution of a conflict of interest by our General Partner that is fair and reasonable to us will be deemed approved by all partners and will not constitute a breach of the partnership agreement.
- Our General Partner controls the enforcement of obligations owed to us by it.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our General Partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our General Partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us.
- In some instances, our General Partner may cause us to borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

Affiliates of our General Partner may compete with us.

Except as provided in our partnership agreement, affiliates and related parties of our General Partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us.

Risks Related to Our Business

We do not control, and therefore may not be able to cause or prevent certain actions by, certain of our joint ventures.

Certain of our joint ventures have their own governing boards, and we may not control all of the decisions of those boards. Consequently, it may be difficult or impossible for us to cause the joint venture entity to take actions that we believe would be in our or the joint venture's best interests. Likewise, we may be unable to prevent actions of the joint venture.

We are exposed to the credit risk of our customers and derivative counterparties, and an increase in the nonpayment and nonperformance by our customers or derivative counterparties could reduce our ability to make distributions to our Unitholders.

The risks of nonpayment and nonperformance by our customers are a major concern in our business. Participants in the energy industry have been subjected to heightened scrutiny from the financial markets in light of past collapses and failures of other energy companies. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. The current commodity price volatility and the tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in the nonpayment and nonperformance by our customers. To the extent one or more of our customers is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our risk management policies and procedures are not properly followed. Any material nonpayment or nonperformance by our customers or our derivative counterparties could reduce our ability to make distributions to our Unitholders. Any substantial increase in the nonpayment and nonperformance by our customers could have a material effect on our results of operations and operating cash flows.

Income from our midstream, transportation, terminalling and storage operations is exposed to risks due to fluctuations in the demand for and price of natural gas, NGLs and oil that are beyond our control.

The prices for natural gas, NGLs and oil (including refined petroleum products) reflect market demand that fluctuates with changes in global and United States economic conditions and other factors, including:

- the level of domestic natural gas, NGL, and oil production;
- the level of natural gas, NGL, and oil imports and exports, including liquefied natural gas;
- actions taken by natural gas and oil producing nations;
- instability or other events affecting natural gas and oil producing nations;
- the impact of weather and other events of nature on the demand for natural gas, NGLs and oil;
- the availability of storage, terminal and transportation systems, and refining, processing and treating facilities;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas;
- the cost of capital needed to maintain or increase production levels and to construct and expand facilities
- the impact of energy conservation and fuel efficiency efforts; and
- the extent of governmental regulation, taxation, fees and duties.

In the past, the prices of natural gas, NGLs and oil have been extremely volatile, and we expect this volatility to continue.

Any loss of business from existing customers or our inability to attract new customers due to a decline in demand for natural gas, NGLs, or oil could have a material adverse effect on our revenues and results of operations. In addition, significant price fluctuations for natural gas, NGL and oil commodities could materially affect our profitability.

We are affected by competition from other midstream, transportation, terminalling and storage companies.

We experience competition in all of our business segments. With respect to our midstream operations, we compete for both natural gas supplies and customers for our services. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas.

Our natural gas and NGL transportation pipelines and storage facilities compete with other interstate and intrastate pipeline companies and storage providers in the transportation and storage of natural gas and NGLs. The principal elements of competition among pipelines are rates, terms of service, access to sources of supply and the flexibility and reliability of service. Natural gas and NGLs also competes with other forms of energy, including electricity, coal, fuel oils and renewable or alternative energy. Competition among fuels and energy supplies is primarily based on price; however, non-price factors, including governmental regulation, environmental impacts, efficiency, ease of use and handling, and the availability of subsidies and tax benefits also affects competitive outcomes.

In markets served by our NGL pipelines, we compete with other pipeline companies and barge, rail and truck fleet operations. We also face competition with other storage and fractionation facilities based on fees charged and the ability to receive, distribute and/or fractionate the customer's products.

Our crude oil and refined petroleum products pipelines face significant competition from other pipelines for large volume shipments. These operations also face competition from trucks for incremental and marginal volumes in the areas we serve. Further, our crude and refined product terminals compete with terminals owned by integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

We may be unable to retain or replace existing midstream, transportation, terminalling and storage customers or volumes due to declining demand or increased competition in oil, natural gas and NGL markets, which would reduce our revenues and limit our future profitability.

The retention or replacement of existing customers and the volume of services that we provide at rates sufficient to maintain or increase current revenues and cash flows depends on a number of factors beyond our control, including the price of and demand for oil, natural gas, and NGLs in the markets we serve and competition from other service providers.

A significant portion of our sales of natural gas are to industrial customers and utilities. As a consequence of the volatility of natural gas prices and increased competition in the industry and other factors, industrial customers, utilities and other gas customers are increasingly reluctant to enter into long-term purchase contracts. Many customers purchase natural gas from more than one supplier and have the ability to change suppliers at any time. Some of these customers also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are many companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in natural gas sales markets primarily on the basis of price.

We also receive a substantial portion of our revenues by providing natural gas gathering, processing, treating, transportation and storage services. While a substantial portion of our services are sold under long-term contracts for reserved service, we also provide service on an unreserved or short-term basis. Demand for our services may be substantially reduced due to changing market prices. Declining prices may result in lower rates of natural gas production resulting in less use of services, while rising prices may diminish consumer demand and also limit the use of services. In addition, our competitors may attract our customers' business. If demand declines or competition increases, we may not be able to sustain existing levels of unreserved service or renew or extend long-term contracts as they expire or we may reduce our rates to meet competitive pressures.

Revenue from our NGL transportation systems and refined products storage is also exposed to risks due to fluctuations in demand for transportation and storage service as a result of unfavorable commodity prices, competition from nearby pipelines, and other factors. We receive substantially all of our transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to our transportation system. Reduction in demand for natural gas or NGLs due to unfavorable prices or other factors, however, may result lower rates of production under dedicated contracts and lower demand for our services. In addition, our refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers, a portion of our revenue is derived from fungible storage and throughput arrangements, under which our revenue is more dependent upon demand for storage from our customers.

The volume of crude oil and products transported through our oil pipelines and terminal facilities depends on the availability of attractively priced crude oil and refined products in the areas serviced by our assets. A period of sustained price reductions for crude oil or refined products could lead to a decline in drilling activity, production and refining of crude oil, or import levels in these areas. A period of sustained increases in the price of crude oil or products supplied from or delivered to any of these areas could materially reduce demand for crude oil or refined in these areas. In either case, the volumes of crude oil or products transported in our oil pipelines and terminal facilities could decline.

The loss of existing customers by our midstream, transportation, terminalling and storage facilities or a reduction in the volume of the services our customers purchase from us, or our inability to attract new customers and service volumes would negatively affect our revenues, be detrimental to our growth, and adversely affect our results of operations.

Our midstream facilities and transportation pipelines are attached to basins with naturally declining production, which we may not be able to replace with new sources of supply.

In order to maintain or increase throughput levels on our gathering systems and transportation pipeline systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies and natural gas transportation services.

A substantial portion of our assets, including our gathering systems and our processing and treating plants, are connected to natural gas reserves and wells that experience declining production over time. Our gas transportation pipelines are also dependent upon natural gas production in areas served by our gathering systems or in areas served by other gathering systems or transportation pipelines that connect with our transportation pipelines. We may not be able to obtain additional contracts for natural gas supplies for our natural gas gathering systems, and we may be unable to maintain or increase the levels of natural gas throughput on our transportation pipelines. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity and production of natural gas near our gathering systems or in areas that provide access to our transportation pipelines or markets to which our systems connect. We have no control over the level of drilling activity in our areas of operation, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, we have no control over producers or their production and contracting decisions.

While a substantial portion of our services are provided under long-term contracts for reserved service, we also provide service on an unreserved basis. The reserves available through the supply basins connected to our gathering, processing, treating, transportation and storage facilities may decline and may not be replaced by other sources of supply. A decrease in development or production activity could cause a decrease in the volume of unreserved services we provide and a decrease in the number and volume of our contracts for reserved transportation service over the long run, which in each case would adversely affect our revenues and results of operations.

If we are unable to replace any significant volume declines with additional volumes from other sources, our results of operations and cash flows could be materially and adversely affected.

The profitability of certain activities in our natural gas gathering, processing, transportation and storage operations are largely dependent upon natural gas commodity prices, price spreads between two or more physical locations and market demand for natural gas and NGLs.

For a portion of the natural gas gathered on our systems, we purchase natural gas from producers at the wellhead and then gather and deliver the natural gas to pipelines where we typically resell the natural gas under various arrangements, including sales at index prices. Generally, the gross margins we realize under these arrangements decrease in periods of low natural gas prices.

We also enter into percent-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which we agree to gather and process natural gas received from the producers.

Under percent-of-proceeds arrangements, we generally sell the residue gas and NGLs at market prices and remit to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes we keep to third parties at market prices. Under these arrangements, our revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on our revenues and results of operations.

Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, our gross margins generally decrease when the price of natural gas increases relative to the price of NGLs.

When we process the gas for a fee under processing fee agreements, we may guarantee recoveries to the producer. If recoveries are less than those guaranteed to the producer, we may suffer a loss by having to supply liquids or its cash equivalent to keep the producer whole.

We also receive fees and retain gas in kind from our natural gas transportation and storage customers. Our fuel retention fees and the value of gas that we retain in kind are directly affected by changes in natural gas prices. Decreases in natural gas prices tend to decrease our fuel retention fees and the value of retained gas.

In addition, we receive revenue from our off-gas processing and fractionating system in south Louisiana primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenue is exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.

For our midstream segment, we generally analyze gross margin based on fee-based margin (which includes revenues from processing fee arrangements) and non-fee based margin (which includes gross margin earned on percent-of-proceeds and keep-whole arrangements). For the years ended December 31, 2017, 2016 and 2015, gross margin from our midstream segment totaled $2.18 billion, $1.80 billion and $1.79 billion, respectively, of which fee-based revenues constituted 78%, 86% and 88%, respectively, and non-fee based margin constituted 22%, 14% and 12%, respectively. The amount of gross margin earned by our midstream segment from fee-based and non-fee based arrangements (individually and as a percentage of total revenues) will be impacted by the volumes associated with both types of arrangements, as well as commodity prices; therefore, the dollar amounts and the relative magnitude of gross margin from fee-based and non-fee based arrangements in future periods may be significantly different from results reported in previous periods.

A material decrease in demand or distribution of crude oil available for transport through our pipelines or terminal facilities could materially and adversely affect our results of operations, financial position, or cash flows.

The volume of crude oil transported through our crude oil pipelines and terminal facilities depends on the availability of attractively priced crude oil produced or received in the areas serviced by our assets. A period of sustained crude oil price declines could lead to a decline in drilling activity, production and import levels in these areas. Similarly, a period of sustained increases in the price of crude oil supplied from any of these areas, as compared to alternative sources of crude oil available to our customers, could materially reduce demand for crude oil in these areas. In either case, the volumes of crude oil transported in our crude oil pipelines and terminal facilities could decline, and it could likely be difficult to secure alternative sources of attractively priced crude oil supply in a timely fashion or at all. If we are unable to replace any significant volume declines with additional volumes from other sources, our results of operations, financial position, or cash flows could be materially and adversely affected.

An interruption of supply of crude oil to our facilities could materially and adversely affect our results of operations and revenues.

While we are well positioned to transport and receive crude oil by pipeline, marine transport and trucks, rail transportation also serves as a critical link in the supply of domestic crude oil production to United States refiners, especially for crude oil from regions such as the Bakken that are not sourced near pipelines or waterways that connect to all of the major United States refining centers. Federal regulators have issued a safety advisory warning that Bakken crude oil may be more volatile than many other North American crude oils and reinforcing the requirement to properly test, characterize, classify, and, if applicable, sufficiently degasify hazardous materials prior to and during transportation. The domestic crude oil received by our facilities, especially from the Bakken region, may be transported by railroad. If the ability to transport crude oil by rail is disrupted because of accidents, weather interruptions, governmental regulation, congestion on rail lines, terrorism, other third-party action or casualty or other events, then we could experience an interruption of supply or delivery or an increased cost of receiving crude oil, and could experience a decline in volumes received. Recent railcar accidents in Quebec, Alabama, North Dakota, Pennsylvania and Virginia, in each case involving trains carrying crude oil from the Bakken region, have led to increased legislative and regulatory scrutiny over the safety of transporting crude oil by rail. In 2015, the DOT, through the PHMSA, issued a rule implementing new rail car standards and railroad operating procedures. Changing operating practices, as well as new regulations on tank car standards and shipper classifications, could increase the time required to move crude oil from production areas of facilities, increase the cost of rail transportation, and decrease the efficiency of transportation of crude oil by rail, any of which could materially reduce the volume of crude oil received by rail and adversely affect our financial condition, results of operations, and cash flows.

The use of derivative financial instruments could result in material financial losses by us.

From time to time, we have sought to reduce our exposure to fluctuations in commodity prices and interest rates by using derivative financial instruments and other risk management mechanisms and by our trading, marketing and/or system optimization activities. To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions that are effective economically (whether to mitigate our exposure to fluctuations in commodity prices, or to balance our exposure to fixed and variable interest rates), these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at that point. It is also not always possible for us to engage in a hedging transaction that completely mitigates our exposure to commodity prices. Our consolidated financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge.

In addition, our derivatives activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the derivative arrangement, the hedge is imperfect, commodity prices move unfavorably related to our physical or financial positions or hedging policies and procedures are not followed.

Our revenues depend on our customers' ability to use our pipelines and third-party pipelines over which we have no control.

Our natural gas transportation, storage and NGL businesses depend, in part, on our customers' ability to obtain access to pipelines to deliver gas to us and receive gas from us. Many of these pipelines are owned by parties not affiliated with us. Any interruption of service on our pipelines or third-party pipelines due to testing, line repair, reduced operating pressures, or other causes or adverse change in terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport natural gas to and from our pipelines and facilities and a corresponding material adverse effect on our transportation and storage revenues. In addition, the rates charged by interconnected pipelines for transportation to and from our facilities affect the utilization and value of our storage services. Significant changes in the rates charged by those pipelines or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on our storage revenues.

Shippers using our oil pipelines and terminals are also dependent upon our pipelines and connections to third-party pipelines to receive and deliver crude oil and products. Any interruptions or reduction in the capabilities of these pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes transported in our pipelines or through our terminals. Similarly, if additional shippers begin transporting volume over interconnecting oil pipelines, the allocations of pipeline capacity to our existing shippers on these interconnecting pipelines could be reduced, which also could reduce volumes transported in its pipelines or through our terminals. Allocation reductions of this nature are not infrequent and are beyond our control. Any such interruptions or allocation reductions that, individually or in the aggregate, are material or continue for a sustained period of time could have a material adverse effect on our results of operations, financial position, or cash flows.

The inability to continue to access lands owned by third parties could adversely affect our ability to operate and our financial results.

Our ability to operate our pipeline systems on certain lands owned by third parties, will depend on our success in maintaining existing rights-of-way and obtaining new rights-of-way on those lands. We are parties to rights-of-way agreements, permits and licenses authorizing land use with numerous parties, including, private land owners, governmental entities, Native American tribes, rail carriers, public utilities and others. Our ability to secure extensions of existing agreements, permits and licenses is essential to our continuing business operations, and securing additional rights-of-way will be critical to our ability to pursue expansion projects. We cannot provide any assurance that we will be able to maintain access to existing rights-of-way upon the expiration of the current grants, that all of the rights-of-way will be obtained in a timely fashion or that we will acquire new rights-of-way as needed.

Further, whether we have the power of eminent domain for our pipelines varies from state to state, depending upon the type of pipeline and the laws of the particular state and the ownership of the land to which we seek access. When we exercise eminent down rights or negotiate private agreements cases, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. The inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located. For example, following a recent decision issued in May 2017 by the federal Tenth Circuit Court of Appeals, tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Indian landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where an existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators. Any loss of rights with respect to our real property, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to you.

We may not be able to fully execute our growth strategy if we encounter increased competition for qualified assets.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream, transportation, storage and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversify our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding the acquisition of additional assets and businesses, stand-alone development projects or other transactions that we believe will present opportunities to realize synergies and increase our cash flow.

Consistent with our strategy, we may, from time to time, engage in discussions with potential sellers regarding the possible acquisition of additional assets or businesses. Such acquisition efforts may involve our participation in processes that involve a number of potential buyers, commonly referred to as "auction" processes, as well as situations in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. We cannot give assurance that our acquisition efforts will be successful or that any acquisition will be completed on terms considered favorable to us.

In addition, we are experiencing increased competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in us losing to other bidders more often or acquiring assets at higher prices, both of which

would limit our ability to fully execute our growth strategy. Inability to execute our growth strategy may materially adversely impact our results of operations.

An impairment of goodwill and intangible assets could reduce our earnings.

As of December 31, 2017, our consolidated balance sheet reflected $3.12 billion of goodwill and $5.31 billion of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States require us to test goodwill for impairment on an annual basis or when events or circumstances occur, indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' capital and balance sheet leverage as measured by debt to total capitalization.

During the fourth quarter of 2017, the Partnership performed goodwill impairment tests on our reporting units and recognized goodwill impairments of $262 million in the interstate transportation and storage segment, $79 million in the NGL and refined products transportation and services segment and $452 million in the all other segment primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded.

During the fourth quarter of 2016, we performed goodwill impairment tests on our reporting units and recognized goodwill impairments of $638 million in the interstate transportation and storage segment and $32 million in the midstream segment. These goodwill impairments were primarily due to decreases in projected future revenues and cash flows driven by declines in commodity prices and changes in the markets that these assets serve. In 2015, we recorded goodwill impairments of $99 million related to Transwestern due primarily to the market declines in current and expected future commodity prices in the fourth quarter of 2015 and $106 million related to Lone Star Refinery Services due primarily to changes in assumptions related to potential future revenues as well as the market declines in current and expected future commodity prices, as well as $24 million of intangible asset impairments related to Lone Star NGL Refinery Services primarily due to the economic obsolescence identified as a result of expected decrease in future cash flows.

If we do not make acquisitions on economically acceptable terms, our future growth could be limited.

Our results of operations and our ability to grow and to increase distributions to Unitholders will depend in part on our ability to make acquisitions that are accretive to our distributable cash flow per unit.

We may be unable to make accretive acquisitions for any of the following reasons, among others:

- because we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- because we are unable to raise financing for such acquisitions on economically acceptable terms; or
- because we are outbid by competitors, some of which are substantially larger than us and have greater financial resources and lower costs of capital then we do.

Furthermore, even if we consummate acquisitions that we believe will be accretive, those acquisitions may in fact adversely affect our results of operations or result in a decrease in distributable cash flow per unit. Any acquisition involves potential risks, including the risk that we may:

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- decrease our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- significantly increase our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- encounter difficulties operating in new geographic areas or new lines of business;
- incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate our growing business and assets;
- less effectively manage our historical assets, due to the diversion of management's attention from other business concerns; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

If we consummate future acquisitions, our capitalization and results of operations may change significantly. As we determine the application of our funds and other resources, Unitholders will not have an opportunity to evaluate the economic, financial and other relevant information that we will consider.

Integration of assets acquired in past acquisitions or future acquisitions with our existing business will be a complex and time-consuming process. A failure to successfully integrate the acquired assets with our existing business in a timely manner may have a material adverse effect on our business, financial condition, results of operations or cash available for distribution to our unitholders.

The difficulties of integrating past and future acquisitions with our business include, among other things:

- operating a larger combined organization in new geographic areas and new lines of business;
- hiring, training or retaining qualified personnel to manage and operate our growing business and assets;
- integrating management teams and employees into existing operations and establishing effective communication and information exchange with such management teams and employees;
- diversion of management's attention from our existing business;
- assimilation of acquired assets and operations, including additional regulatory programs;
- loss of customers or key employees;
- maintaining an effective system of internal controls in compliance with the Sarbanes-Oxley Act of 2002 as well as other regulatory compliance and corporate governance matters; and
- integrating new technology systems for financial reporting.

If any of these risks or other unanticipated liabilities or costs were to materialize, then desired benefits from past acquisitions and future acquisitions resulting in a negative impact to our future results of operations. In addition, acquired assets may perform at levels below the forecasts used to evaluate their acquisition, due to factors beyond our control. If the acquired assets perform at levels below the forecasts, then our future results of operations could be negatively impacted.

Also, our reviews of proposed business or asset acquisitions are inherently imperfect because it is generally not feasible to perform an in-depth review of each such proposal given time constraints imposed by sellers. Even if performed, a detailed review of assets and businesses may not reveal existing or potential problems, and may not provide sufficient familiarity with such business or assets to fully assess their deficiencies and potential. Inspections may not be performed on every asset, and environmental problems, may not be observable even when an inspection is undertaken.

If we do not continue to construct new pipelines, our future growth could be limited.

Our results of operations and ability to grow and to increase distributable cash flow per unit will depend, in part, on our ability to construct pipelines that are accretive to our distributable cash flow. We may be unable to construct pipelines that are accretive to distributable cash flow for any of the following reasons, among others:

- we are unable to identify pipeline construction opportunities with favorable projected financial returns;
- we are unable to obtain necessary governmental approvals and contracts with qualified contractors and vendors on acceptable terms;
- we are unable to raise financing for our identified pipeline construction opportunities; or
- we are unable to secure sufficient transportation commitments from potential customers due to competition from other pipeline construction projects or for other reasons.

Furthermore, even if we construct a pipeline that we believe will be accretive, the pipeline may in fact adversely affect our results of operations or results from those projected prior to commencement of construction and other factors.

Expanding our business by constructing new pipelines and related facilities subjects us to risks.

One of the ways that we have grown our business is through the construction of additions to our existing gathering, compression, treating, processing and transportation systems. The construction of new pipelines and related facilities (or the improvement and repair of existing facilities) involves numerous regulatory, environmental, political and legal uncertainties beyond our control and requires the expenditure of significant amounts of capital that we will be required to finance through borrowings, the issuance of additional equity or from operating cash flow. If we undertake these projects, they may not be completed on schedule, at all, or at the budgeted cost. A variety of factors outside our control, such as weather, natural disasters and difficulties in obtaining permits

and rights-of-way or other regulatory approvals, as well as the performance by third-party contractors, may result in increased costs or delays in construction. Cost overruns or delays in completing a project could have a material adverse effect on our results of operations and cash flows. Moreover, our revenues may not increase immediately following the completion of a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time, but we may not materially increase our revenues until long after the project's completion. In addition, the success of a pipeline construction project will likely depend upon the level of oil and natural gas exploration and development drilling activity and the demand for pipeline transportation in the areas proposed to be serviced by the project as well as our ability to obtain commitments from producers in the area to utilize the newly constructed pipelines. In this regard, we may construct facilities to capture anticipated future growth in oil or natural gas production in a region in which such growth does not materialize. As a result, new facilities may be unable to attract enough throughput or contracted capacity reservation commitments to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

We depend on certain key producers for our supply of natural gas and the loss of any of these key producers could adversely affect our financial results.

Certain producers who are connected to our systems represent a material source of our supply of natural gas. We are not the only option available to these producers for disposition of the natural gas they produce. To the extent that these and other producers may reduce the volumes of natural gas that they supply us, we would be adversely affected unless we were able to acquire comparable supplies of natural gas from other producers.

Our intrastate transportation and storage and interstate transportation and storage operations depend on key customers to transport natural gas through our pipelines and the pipelines of our joint ventures.

During 2017, Trafigura US Inc., KMI, and Calpine Energy Services L.P. collectively accounted for approximately 36% of our intrastate transportation and storage revenues. During 2017, Chesapeake Energy Marketing, Inc., EnCana Marketing (USA), Inc. and Shell Energy North America (US), L.P., collectively accounted for 19% of our interstate transportation and storage revenues.

Our joint ventures, FEP and Citrus, also depend on key customers for the transport of natural gas through their pipelines. FEP has a small number of major shippers with one shipper accounting for approximately 64% of its revenues in 2017 while Citrus has long-term agreements with its top two customers which accounted for 61% of its 2017 revenue. For Trans-Pecos and Comanche Trail, CFE International LLC is the sole shipper.

The failure of the major shippers on our and our joint ventures' intrastate and interstate transportation and storage pipelines to fulfill their contractual obligations could have a material adverse effect on our cash flow and results of operations if we or our joint ventures were unable to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

Our interstate natural gas pipelines are subject to laws, regulations and policies governing the rates they are allowed to charge for their services, which may prevent us from fully recovering our costs.

Laws, regulations and policies governing interstate natural gas pipeline rates could affect the ability of our interstate pipelines to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs.

We are required to file tariff rates (also known as recourse rates) with the FERC that shippers may pay for interstate natural gas transportation services. We may also agree to discount these rates on a not unduly discriminatory basis or negotiate rates with shippers who elect not to pay the recourse rates. The FERC must approve or accept all rate filings for us to be allowed to charge such rates.

The FERC may review existing tariff rates on its own initiative or upon receipt of a complaint filed by a third party. The FERC may, on a prospective basis, order refunds of amounts collected if it finds the rates to have been shown not to be just and reasonable or to have been unduly discriminatory. The FERC has recently exercised this authority with respect to several other pipeline companies. If the FERC were to initiate a proceeding against us and find that our rates were not just and reasonable or unduly discriminatory, the maximum rates we are permitted to charge may be reduced and the reduction could have an adverse effect on our revenues and results of operations.

The costs of our interstate pipeline operations may increase and we may not be able to recover all of those costs due to FERC regulation of our rates. If we propose to change our tariff rates, our proposed rates may be challenged by the FERC or third parties, and the FERC may deny, modify or limit our proposed changes if we are unable to persuade the FERC that changes would result in just and reasonable rates that are not unduly discriminatory. We also may be limited by the terms of rate case settlement agreements or negotiated rate agreements with individual customers from seeking future rate increases, or we may be constrained by competitive factors from charging our tariff rates.

To the extent our costs increase in an amount greater than our revenues increase, or there is a lag between our cost increases and our ability to file for and obtain rate increases, our operating results would be negatively affected. Even if a rate increase is permitted by the FERC to become effective, the rate increase may not be adequate. We cannot guarantee that our interstate pipelines will be able to recover all of our costs through existing or future rates.

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before the FERC and the courts for a number of years. It is currently the FERC's policy to permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential income tax liability on their public utility income attributable to all partnership or limited liability company interests, to the extent that the ultimate owners have an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Under the FERC's policy, we thus remain eligible to include an income tax allowance in the tariff rates we charge for interstate natural gas transportation. On December 15, 2016, FERC issued a Notice of Inquiry requesting energy industry input on how FERC should address income tax allowances in cost-based rates proposed by pipeline companies organized as part of a master limited partnership. FERC issued the Notice of Inquiry in response to a remand from the United States Court of Appeals for the D.C. Circuit in United Airlines v. FERC, in which the court determined that FERC had not justified its conclusion that an oil pipeline organized as a partnership would not "double recover" its taxes under the current policy by both including a tax allowance in its cost-based rates and earning a return on equity calculated on a pre-tax basis. FERC requested comments regarding how to address any double recovery resulting from the Commission's current income tax allowance and rate of return policies. The comment period with respect to the notice of inquiry ended on April 7, 2017. The outcome of the inquiry is still pending. We cannot predict whether FERC will successfully justify its conclusion that there is no double recovery of taxes under these circumstances or whether FERC will modify its current policy on either income tax allowances or return on equity calculations for pipeline companies organized as part of a master limited partnership. However, any modification that reduces or eliminates an income tax allowance for pipeline companies organized as part of a master limited partnership or decreases the return on equity for such pipelines could result in an adverse impact on our revenues associated with the transportation and storage services we provide pursuant to cost-based rates.

Effective January 2018, the 2017 Tax Cuts and Jobs Act changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. Following the 2017 Tax Cuts and Jobs Act being signed into law, filings have been made at FERC requesting that FERC require pipelines to lower their transportation rates to account for lower taxes. Following the effective date of the law, the FERC orders granting certificates to construct proposed pipeline facilities have directed pipelines proposing new rates for service on those facilities to re-file such rates so that the rates reflect the reduction in the corporate tax rate, and FERC has issued data requests in pending certificate proceedings for proposed pipeline facilities requesting pipelines to explain the impacts of the reduction in the corporate tax rate on the rate proposals in those proceedings and to provide re-calculated initial rates for service on the proposed pipeline facilities. FERC may enact other regulations or issue further requests to pipelines regarding the impact of the corporate tax rate change on the rates. The FERC's establishment of a just and reasonable rate is based on many components, and the reduction in the corporate tax rate may impact two of such components: the allowance for income taxes and the amount for accumulated deferred income taxes. Because our existing jurisdictional rates were established based on a higher corporate tax rate, FERC or our shippers may challenge these rates in the future, and the resulting new rate may be lower than the rates we currently charge.

Our interstate natural gas pipelines are subject to laws, regulations and policies governing terms and conditions of service, which could adversely affect our business and results of operations.

In addition to rate oversight, the FERC's regulatory authority extends to many other aspects of the business and operations of our interstate natural gas pipelines, including:

- terms and conditions of service;
- the types of services interstate pipelines may or must offer their customers;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- accounts and records; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. In addition, we cannot guarantee that the FERC will authorize tariff changes and other activities we might propose and to undertake in a timely manner and free from potentially burdensome conditions. Future changes to laws, regulations, policies and interpretations thereof may impair our access to capital markets or

may impair the ability of our interstate pipelines to compete for business, may impair their ability to recover costs or may increase the cost and burden of operation.

The current FERC Chairman announced in December 2017 that FERC will review its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed that will affect our natural gas pipeline business or when such proposals, if any, might become effective. We do not expect that any change in this policy would affect us in a materially different manner than any other similarly sized natural gas pipeline company operating in the United States.

Rate regulation or market conditions may not allow us to recover the full amount of increases in the costs of our crude oil, NGL and products pipeline operations.

Transportation provided on our common carrier interstate crude oil, NGL and products pipelines is subject to rate regulation by the FERC, which requires that tariff rates for transportation on these oil pipelines be just and reasonable and not unduly discriminatory. If we propose new or changed rates, the FERC or interested persons may challenge those rates and the FERC is authorized to suspend the effectiveness of such rates for up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the proposed rate is unjust or unreasonable, it is authorized to require the carrier to refund revenues in excess of the prior tariff during the term of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

The primary ratemaking methodology used by the FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. The FERC's ratemaking methodologies may limit our ability to set rates based on our costs or may delay the use of rates that reflect increased costs. In October 2016, FERC issued an Advance Notice of Proposed Rulemaking seeking comment on a number of proposals, including: (1) whether the Commission should deny any increase in a rate ceiling or annual index-based rate increase if a pipeline's revenues exceed total costs by 15% for the prior two years; (2) a new percentage comparison test that would deny a proposed increase to a pipeline's rate or ceiling level greater than 5% above the barrel-mile cost changes; and (3) a requirement that all pipelines file indexed ceiling levels annually, with the ceiling levels subject to challenge and restricting the pipeline's ability to carry forward the full indexed increase to a future period. The comment period with respect to the proposed rules ended March 17, 2017. FERC has not yet taken any further action on the proposed rule. If the FERC's indexing methodology changes, the new methodology could materially and adversely affect our financial condition, results of operations or cash flows.

Under the EPAct of 1992, certain interstate pipeline rates were deemed just and reasonable or "grandfathered." Revenues are derived from such grandfathered rates on most of our FERC-regulated pipelines. A person challenging a grandfathered rate must, as a threshold matter, establish a substantial change since the date of enactment of the Energy Policy Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. If the FERC were to find a substantial change in circumstances, then the existing rates could be subject to detailed review and there is a risk that some rates could be found to be in excess of levels justified by the pipeline's costs. In such event, the FERC could order us to reduce pipeline rates prospectively and to pay refunds to shippers.

If the FERC's petroleum pipeline ratemaking methodologies procedures changes, the new methodology or procedures could adversely affect our business and results of operations.

State regulatory measures could adversely affect the business and operations of our midstream and intrastate pipeline and storage assets.

Our midstream and intrastate transportation and storage operations are generally exempt from FERC regulation under the NGA, but FERC regulation still significantly affects our business and the market for our products. The rates, terms and conditions of service for the interstate services we provide in our intrastate gas pipelines and gas storage are subject to FERC regulation under Section 311 of the NGPA. Our HPL System, East Texas pipeline, Oasis pipeline and ET Fuel System provide such services. Under Section 311, rates charged for transportation and storage must be fair and equitable. Amounts collected in excess of fair and equitable rates are subject to refund with interest, and the terms and conditions of service, set forth in the pipeline's statement of operating conditions, are subject to FERC review and approval. Should the FERC determine not to authorize rates equal to or greater than our costs of service, our cash flow would be negatively affected.

Our midstream and intrastate gas and oil transportation pipelines and our intrastate gas storage operations are subject to state regulation. All of the states in which we operate midstream assets, intrastate pipelines or intrastate storage facilities have adopted some form of complaint-based regulation, which allow producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to the fairness of rates and terms of access. The states in which we operate have ratable take statutes, which generally require gatherers to take, without undue discrimination, production that may be tendered to the gatherer for

handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Should a complaint be filed in any of these states or should regulation become more active, our business may be adversely affected.

Our intrastate transportation operations located in Texas are also subject to regulation as gas utilities by the TRRC. Texas gas utilities must publish the rates they charge for transportation and storage services in tariffs filed with the TRRC, although such rates are deemed just and reasonable under Texas law unless challenged in a complaint.

We are subject to other forms of state regulation, including requirements to obtain operating permits, reporting requirements, and safety rules (see description of federal and state pipeline safety regulation below). Violations of state laws, regulations, orders and permit conditions can result in the modification, cancellation or suspension of a permit, civil penalties and other relief.

Certain of our assets may become subject to regulation.

The distinction between federally unregulated gathering facilities and FERC-regulated transmission pipelines under the NGA has been the subject of extensive litigation and may be determined by the FERC on a case-by-case basis, although the FERC has made no determinations as to the status of our facilities. Consequently, the classification and regulation of our gathering facilities could change based on future determinations by the FERC, the courts or Congress. If our gas gathering operations become subject to FERC jurisdiction, the result may adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of our gathering agreements with our customers.

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. Lone Star's NGL Pipeline transports NGLs within the state of Texas and is subject to regulation by the TRRC. This NGLs transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. In 2013, Lone Star's NGL pipeline also commenced the interstate transportation of NGLs, which is subject to FERC's jurisdiction under the Interstate Commerce Act and the Energy Policy Act of 1992. Both intrastate and interstate NGL transportation services must be provided in a manner that is just, reasonable, and non-discriminatory. The tariff rates established for interstate services were based on a negotiated agreement; however, if FERC's ratemaking methodologies were imposed, they may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. In addition, the rates, terms and conditions for shipments of crude oil, petroleum products and NGLs on our pipelines are subject to regulation by FERC if the NGLs are transported in interstate or foreign commerce, whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all crude oil, petroleum products and NGLs on our pipelines, FERC regulation could be triggered by our customers' transportation decisions.

In addition, if any of our pipelines were found to have provided services or otherwise operated in violation of the NGA, NGPA, or ICA, this could result in the imposition of administrative and criminal remedies and civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by the FERC. Any of the foregoing could adversely affect revenues and cash flow related to these assets.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.

Pursuant to authority under the NGPSA and HLPSA, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for natural gas transmission and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect HCAs which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources, and unusually sensitive ecological areas. These regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. 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. Any changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, in January 2017, PHMSA issued a final rule for hazardous liquid pipelines that significantly expands the reach of certain PHMSA integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline's proximity to a HCA. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, the date of implementation of this final rule by publication in the Federal Register is uncertain given the recent change in Presidential Administrations. In a second example, in April 2016, PHMSA published a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined "moderate consequence areas" that contain as few as 5 dwellings within a potential impact area; requiring gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressure ("MAOP"); and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements and also require consideration of seismicity in evaluating threats to pipelines. The changes adopted or proposed by these rulemakings or made in future legal requirements could have a material adverse effect on our results of operations and costs of transportation services.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

The NGPSA and HLPSA were amended by the 2011 Pipeline Safety Act. Among other things, the 2011 Pipeline Safety Act increased the penalties for safety violations and directed the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm that the material strength of certain pipelines are above 30% of specified minimum yield strength, and operator verification of records confirming the MAOP of certain interstate natural gas transmission pipelines. Effective April 27, 2017, maximum administrative fines for safety violations were increased to account for inflation, with maximum civil penalties set at $209,002 per day, with a maximum of $2,090,022 for a series of violations. In June 2016, the 2016 Pipeline Safety Act was passed, extending PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and developing new safety standards for natural gas storage facilities by June 22, 2018. The 2016 Pipeline Safety Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of natural gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as further amended by the 2016 Pipeline Safety Act as well as any implementation of PHMSA rules thereunder or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial condition.

Our business involves the generation, handling and disposal of hazardous substances, hydrocarbons and wastes which activities are subject to environmental and worker health and safety laws and regulations that may cause us to incur significant costs and liabilities.

Our business is subject to stringent federal, tribal state, and local laws and regulations governing the discharge of materials into the environment, worker health and safety and protection of the environment. These laws and regulations may require the acquisition of permits for the construction and operation of our pipelines, plants and facilities, result in capital expenditures to manage, limit or prevent emissions, discharges or releases of various materials from our pipelines, plants and facilities, impose specific health and safety standards addressing worker protection, and impose substantial liabilities for pollution resulting from our construction and operations activities. Several governmental authorities, such as the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them and frequently mandate difficult and costly remediation measures and other actions. Failure to comply with these laws, regulations and permits may result in the assessment of significant administrative, civil and criminal penalties, the imposition of investigatory remedial and corrective action obligations, the occurrence of delays in permitting and completion of projects, and the issuance of injunctive relief. Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or released, even under circumstances where the substances, hydrocarbons or wastes have been released by a predecessor operator. Moreover, it is not uncommon for neighboring landowners and other third parties

to file claims for personal injury and property and natural resource damage allegedly caused by noise, odor or the release of hazardous substances, hydrocarbons or wastes into the environment.

We may incur substantial environmental costs and liabilities because of the underlying risk arising out of our operations. Although we have established financial reserves for our estimated environmental remediation liabilities, additional contamination or conditions may be discovered, resulting in increased remediation costs, liabilities or natural resource damages that could substantially increase our costs for site remediation projects. Accordingly, we cannot assure you that our current reserves are adequate to cover all future liabilities, even for currently known contamination.

Changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, emission standards, or storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. For example, in October 2015, the EPA published a final rule under the Clean Air Act, lowering the NAAQS for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the United States counties as either "attainment/unclassifiable" or "unclassifiable" and is expected to issue non-attainment designations for the remaining areas of the United States not addressed under the November 2017 final rule in the first half of 2018. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to our customers' operations. Compliance with this final rule or any other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines or new restrictions or prohibitions with respect to permits or projects, and significantly increase our capital expenditures and operating costs, which could adversely impact our business. Historically, we have been able to satisfy the more stringent nitrogen oxide emission reduction requirements that affect our compressor units in ozone non-attainment areas at reasonable cost, but there is no assurance that we will not incur material costs in the future to meet the new, more stringent ozone standard.

Product liability claims and litigation could adversely affect our business and results of operations.

Product liability is a significant commercial risk. Substantial damage awards have been made in certain jurisdictions against manufacturers and resellers based upon claims for injuries caused by the use of or exposure to various products. There can be no assurance that product liability claims against us would not have a material adverse effect on our business or results of operations.

Along with other refiners, manufacturers and sellers of gasoline, Sunoco, Inc. is a defendant in numerous lawsuits that allege MTBE contamination in groundwater. Plaintiffs, who include water purveyors and municipalities responsible for supplying drinking water and private well owners, are seeking compensatory damages (and in some cases injunctive relief, punitive damages and attorneys' fees) for claims relating to the alleged manufacture and distribution of a defective product (MTBE-containing gasoline) that contaminates groundwater, and general allegations of product liability, nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. There has been insufficient information developed about the plaintiffs' legal theories or the facts that would be relevant to an analysis of the ultimate liability to Sunoco, Inc. An adverse determination of liability related to these allegations or other product liability claims against Sunoco, Inc. could have a material adverse effect on our business or results of operations.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the services we provide.

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted rules under authority of the Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore processing, transmission, storage and distribution facilities. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain new,

modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, the Subpart OOOOa standards have been subject to attempts by the EPA to stay portions of those standards, and the agency proposed rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of Subpart OOOOa in its entirety. The EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. This rule, should it remain in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France preparing an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. In August 2017, the United States State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. Finally, some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on our assets.

The swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder could have an adverse effect on our ability to use derivative instruments to mitigate the risks of changes in commodity prices and interest rates and other risks associated with our business.

Provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") and rules adopted by the Commodity Futures Trading Commission (the "CFTC"), the SEC and other prudential regulators establish federal regulation of the physical and financial derivatives, including over-the-counter derivatives market and entities, such as us, participating in that market. While most of these regulations are already in effect, the implementation process is still ongoing and the CFTC continues to review and refine its initial rulemakings through additional interpretations and supplemental rulemakings. As a result, any new regulations or modifications to existing regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability and/or liquidity of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. Any of these consequences could have a material adverse effect on our financial condition, results of operations and cash available for distribution to our unitholders.

The CFTC has re-proposed speculative position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, although certain bona fide hedging transactions would be exempt from these position limits provided that various conditions are satisfied. The CFTC has also finalized a related aggregation rule that requires market participants to aggregate their positions with certain other persons under common ownership and control, unless an exemption applies, for purposes of determining whether the position limits have been exceeded. If adopted, the revised position limits rule and its finalized companion rule on aggregation may create additional implementation or operational exposure. In addition to the CFTC federal speculative position limit regime, designated contract markets ("DCMs") also maintain speculative position limit and accountability regimes with respect to contracts listed on their platform as well as aggregation requirements similar to the CFTC's final aggregation rule. Any speculative position limit regime, whether imposed at the federal-level or at the DCM-level may impose added operating costs to monitor compliance with such position limit levels, addressing accountability level concerns and maintaining appropriate exemptions, if applicable.

The Dodd-Frank Act requires that certain classes of swaps be cleared on a derivatives clearing organization and traded on a DCM or other regulated exchange, unless exempt from such clearing and trading requirements, which could result in the application of certain margin requirements imposed by derivatives clearing organizations and their members. The CFTC and prudential regulators have also adopted mandatory margin requirements for uncleared swaps entered into between swap dealers and certain other counterparties. We currently qualify for and rely upon an end-user exception from such clearing and margin requirements for the swaps we enter into to hedge our commercial risks. However, the application of the mandatory clearing and trade execution requirements and the uncleared swaps margin requirements to other market participants, such as swap dealers, may adversely affect the cost and availability of the swaps that we use for hedging.

In addition to the Dodd-Frank Act, the European Union and other foreign regulators have adopted and are implementing local reforms generally comparable with the reforms under the Dodd-Frank Act. Implementation and enforcement of these regulatory provisions may reduce our ability to hedge our market risks with non-U.S. counterparties and may make transactions involving cross-border swaps more expensive and burdensome. Additionally, the lack of regulatory equivalency across jurisdictions may increase compliance costs and make it more difficult to satisfy our regulatory obligations.

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

Because we are a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders do not have the same protections afforded to stockholders of corporations that are subject to all of the corporate governance requirements of the applicable stock exchange.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our Common Units.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas pipeline and other facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes.

If one or more facilities that are owned by us, or that deliver natural gas or other products to us, are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our Unitholders and, accordingly, adversely affect the market price of our Common Units.

As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Terrorist attacks aimed at our facilities could adversely affect our business, results of operations, cash flows and financial condition.

The United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Some of our facilities are subject to standards and procedures required by the Chemical Facility Anti-Terrorism Standards. We believe we are in compliance with all material requirements; however, such compliance may not prevent a terrorist attack from causing material damage to our facilities or pipelines. Any such terrorist attack on our facilities or pipelines, those of our customers, or in some cases, those of other pipelines could have a material adverse effect on our business, financial condition and results of operations.

Additional deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration, development, oil spill-response and decommissioning plans, and other related developments may have a material adverse effect on our business, financial condition, or results of operations.

The federal Bureau of Ocean Energy Management ("BOEM") and the federal Bureau of Safety and Environmental Enforcement ("BSEE"), each agencies of the United States Department of the Interior, have imposed more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. Compliance with these more stringent regulatory requirements and with existing environmental and oil spill regulations, together with any uncertainties or inconsistencies in decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts.

In addition, new regulatory initiatives may be adopted or enforced by the BOEM or the BSEE in the future that could result in additional costs, delays, restrictions, or obligations with respect to oil and natural gas exploration and production operations conducted offshore by certain of our customers. For example, in April 2016, the BOEM published a proposed rule that would update existing air-emissions requirements relating to offshore oil and natural-gas activity on federal Outer Continental Shelf waters. However, in May 2017, Order 3350 was issued by the Department of the Interior Secretary Ryan Zinke, directing the BOEM to reconsider a number of regulatory initiatives governing oil and gas exploration in offshore waters, including, among other things, a cessation of all activities to promulgate the April 2016 proposed rulemaking ("Order 3350"). In an unrelated legal initiative, BOEM issued a Notice to Lessees and Operators ("NTL #2016-N01") that became effective in September 2016 and imposes more stringent requirements relating to the provision of financial assurance to satisfy decommissioning obligations. Together with a recent re-assessment by BSEE in 2016 in how it determines the amount of financial assurance required, the revised BOEM-administered offshore financial assurance program that is currently being implemented is expected to result in increased amounts of financial assurance being required of operators on the OCS, which amounts may be significant. However, as directed under Order 3350, the BOEM has delayed implementation of NTL #2016-N01 so that it may reconsider this regulatory initiative and, currently, this NTL's implementation timeline has been extended indefinitely beyond June 30, 2017, except in certain circumstances where there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities. The April 2016 proposed rule and NTL #2016-N01, should they be finalized and/or implemented, as well as any new rules, regulations, or legal initiatives could delay or disrupt our customers operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, limit activities in certain areas, or cause our customers' to incur penalties, or shut-in production or lease cancellation. Also, if material spill events were to occur in the future, the United States or other countries could elect to issue directives to temporarily cease drilling activities offshore and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development. The overall costs imposed on our customers to implement and complete any such spill response activities or any decommissioning obligations could exceed estimated accruals, insurance limits, or supplemental bonding amounts, which could result in the incurrence of additional costs to complete. We cannot predict with any certainty the full impact of any new laws or regulations on our customers' drilling operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations. The occurrence of any one or more of these developments could result in decreased demand for our services, which could have a material adverse effect on our business as well as our financial position, results of operation and liquidity.

Our business is subject to federal, state and local laws and regulations that govern the product quality specifications of the petroleum products that we store and transport.

The petroleum products that we store and transport are sold by our customers for consumption into the public market. Various federal, state and local agencies have the authority to prescribe specific product quality specifications to commodities sold into the public market. Changes in product quality specifications could reduce our throughput volume, require us to incur additional handling costs or require the expenditure of significant capital. In addition, different product specifications for different markets impact the fungibility of products transported and stored in our pipeline systems and terminal facilities and could require the construction of additional storage to segregate products with different specifications. We may be unable to recover these costs through increased revenues.

In addition, our patented butane blending services are reliant upon gasoline vapor pressure specifications. Significant changes in such specifications could reduce butane blending opportunities, which would affect our ability to market our butane blending service licenses and which would ultimately affect our ability to recover the costs incurred to acquire and integrate our butane blending assets.

Our business could be affected adversely by union disputes and strikes or work stoppages by unionized employees.

As of December 31, 2017, approximately 14% of our workforce is covered by a number of collective bargaining agreements with various terms and dates of expiration. There can be no assurances that we will not experience a work stoppage in the future as a

result of labor disagreements. Any work stoppage could, depending on the affected operations and the length of the work stoppage, have a material adverse effect on our business, financial position, results of operations or cash flows.

Our operations could be disrupted if our information systems fail, causing increased expenses and loss of sales.

Our business is highly dependent on financial, accounting and other data processing systems and other communications and information systems, including our enterprise resource planning tools. We process a large number of transactions on a daily basis and rely upon the proper functioning of computer systems. If a key system was to fail or experience unscheduled downtime for any reason, even if only for a short period, our operations and financial results could be affected adversely. Our systems could be damaged or interrupted by a security breach, fire, flood, power loss, telecommunications failure or similar event. We have a formal disaster recovery plan in place, but this plan may not entirely prevent delays or other complications that could arise from an information systems failure. Our business interruption insurance may not compensate us adequately for losses that may occur.

Cybersecurity breaches and other disruptions could compromise our information and operations, and expose us to liability, which would cause our business and reputation to suffer.

In the ordinary course of our business, we collect and store sensitive data, including intellectual property, our proprietary business information and that of our customers, suppliers and business partners, and personally identifiable information of our employees, in our data centers and on our networks. The secure processing, maintenance and transmission of this information is critical to our operations and business strategy. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties for divulging shipper information, disruption of our operations, damage to our reputation, and loss of confidence in our products and services, which could adversely affect our business.

Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-today operations. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, safety incidents, damage to the environment, potential liability or the loss of contracts, and have a material adverse effect on our operations, financial position and results of operations.

The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results.

Certain of our subsidiaries provide pension plan and other postretirement healthcare benefits to certain of their employees. The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension and other postretirement fund values, changing demographics and fluctuating actuarial assumptions that may have a material adverse effect on the Partnership's future consolidated financial results. While certain of the costs incurred in providing such pension and other postretirement healthcare benefits are recovered through the rates charged by the Partnership's regulated businesses, the Partnership's subsidiaries may not recover all of the costs and those rates are generally not immediately responsive to current market conditions or funding requirements. Additionally, if the current cost recovery mechanisms are changed or eliminated, the impact of these benefits on operating results could significantly increase.

Our contract compression operations depend on particular suppliers and are vulnerable to parts and equipment shortages and price increases, which could have a negative impact on results of operations.

The principal manufacturers of components for our natural gas compression equipment include Caterpillar, Inc. for engines, Air-X-Changers for coolers and Ariel Corporation for compressors and frames. Our reliance on these suppliers involves several risks, including price increases and a potential inability to obtain an adequate supply of required components in a timely manner. We also rely primarily on two vendors, Spitzer Industries Corp. and Standard Equipment Corp., to package and assemble our compression units. We do not have long-term contracts with these suppliers or packagers, and a partial or complete loss of certain of these sources could have a negative impact on our results of operations and could damage our customer relationships.

Mergers among customers and competitors could result in lower volumes being shipped on our pipelines or products stored in or distributed through our terminals, or reduced crude oil marketing margins or volumes.

Mergers between existing customers could provide strong economic incentives for the combined entities to utilize their existing systems instead of our systems in those markets where the systems compete. As a result, we could lose some or all of the volumes and associated revenues from these customers and could experience difficulty in replacing those lost volumes and revenues, which could materially and adversely affect our results of operations, financial position, or cash flows.

Fraudulent activity or misuse of proprietary data involving its outsourcing partners could expose us to additional liability.

We utilize both affiliated entities and third parties in the processing of our information and data. Breaches of security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information, or sensitive or confidential data about us or our customers, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose us to a risk of loss, or misuse of this information, result in litigation and potential liability, lead to reputational damage, increase our compliance costs, or otherwise harm its business.

The liquefaction project is dependent upon securing long-term contractual arrangements for the off-take of LNG on terms sufficient to support the financial viability of the project

LCL, an entity whose parent is owned 60% by ETE and 40% by ETP, is in the process of developing a liquefaction project at the site of ETE's existing regasification facility in Lake Charles, Louisiana. The project development agreement previously entered into in September 2013 with BG Group plc (now "Shell") related to this project expired in February 2017. On June 28, 2017, LCL signed a memorandum of understanding with Korea Gas Corporation and Shell to study the feasibility of a joint development of the Lake Charles liquefaction project. The project would utilize existing dock and storage facilities owned by ETE located on the Lake Charles site. The parties' determination as to the feasibility of the project will be particularly dependent upon the prospects for securing long-term contractual arrangements for the off-take of LNG which in turn will be dependent upon supply and demand factors affecting the price of LNG in foreign markets. The financial viability of the project will also be dependent upon a number of other factors, including the expected cost to construct the liquefaction facility, the terms and conditions of the financing for the construction of the liquefaction facility, the cost of the natural gas supply, the costs to transport natural gas to the liquefaction facility, the costs to operate the liquefaction facility and the costs to transport LNG from the liquefaction facility to customers in foreign markets (particularly Europe and Asia). Some of these costs fluctuate based on a variety of factors, including supply and demand factors affecting the price of natural gas in the United States, supply and demand factors affecting the costs for construction services for large infrastructure projects in the United States, and general economic conditions, there can be no assurance that the parties will determine to proceed to develop this project.

The construction of the liquefaction project remains subject to further approvals and some approvals may be subject to further conditions, review and/or revocation.

While LCL has received authorization from the DOE to export LNG to non-FTA countries, the non-FTA authorization is subject to review, and the DOE may impose additional approval and permit requirements in the future or revoke the non-FTA authorization should the DOE conclude that such export authorization is inconsistent with the public interest. The failure by LCL to timely maintain the approvals necessary to complete and operate the liquefaction project could have a material adverse effect on its operations and financial condition.

Legal actions related to the Dakota Access Pipeline could cause an interruption to operations, which could have an adverse effect on our business and results of operations.

On July 25, 2016, the United States Army Corps of Engineers ("USACE") issued permits to Dakota Access consistent with environmental and historic preservation statutes for the pipeline to make two crossings of the Missouri River in North Dakota, including a crossing of the Missouri River at Lake Oahe. The USACE also issued easements to allow the pipeline to cross land owned by the USACE adjacent to the Missouri River in two locations. The Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the United States District Court for the District of Columbia (the "Court") against the USACE that challenged the legality of the permits issued for the construction of the Dakota Access pipeline and claimed violations of the National Historic Preservation Act ("NHPA"). Dakota Access intervened in the case.

In February 2017, the Department of the Army delivered an easement to Dakota Access allowing the pipeline to cross Lake Oahe. The SRST and Cheyenne River Sioux Tribe ("CRST") (which had intervened in the lawsuit brought by SRST), amended their complaints to incorporate religious freedom and other claims related to treaties and use of government property. The Oglala and Yankton Sioux tribes, and various individual members, filed related lawsuits in opposition to the Dakota Access pipeline. These lawsuits have been consolidated into the action initiated by the SRST.

On June 14, 2017, the Court ruled that the USACE substantially complied with all relevant statutes in connection with the issuance of the permits and easement, but remanded to the USACE three discrete issues for further analysis and explanation of its prior determination under certain of these statutes. On October 11, 2017, the Court ruled that the pipeline could continue to transport crude oil during the pendency of the remand, but requested briefing from the parties as to whether any conditions on the continued operation of the pipeline during this period. On December 4, 2017, the Court determined to impose three conditions on continued operation of the pipeline during the remand process. First, Dakota Access must retain an independent auditor to review its compliance with the conditions and regulations governing its easements and to assess integrity threats to the pipeline. Second, the Court directed Dakota Access to continue its work with the tribes and the USACE to revise and finalize its response planning

for the section of the pipeline crossing Lake Oahe. Third, the Court directed Dakota Access to submit bi-monthly reports during the remand period disclosing certain inspection and maintenance information recommended by PHMSA.

While we believe that the pending lawsuits are unlikely to adversely affect the continued operation of the pipeline, we cannot assure this outcome. At this time, we cannot determine when or how these lawsuits will be resolved or the impact they may have on the Dakota Access project.

In addition, lawsuits of this nature could result in interruptions to construction or operations of future projects, delays in completing those projects and/or increased project costs, all of which could have an adverse effect on our business and results of operations.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or if we become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our Common Units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS, with respect to our classification as a partnership for federal income tax purposes. Despite the fact that we are a limited partnership under Delaware law, we would be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation, we would pay federal income tax at the corporate tax rate, and we would likely pay additional state income taxes at varying rates. Distributions to Unitholders would generally be taxed again as corporate distributions, and none of our income, gains, losses or deductions would flow through to Unitholders. Because a tax would then be imposed upon us as a corporation, our cash available for distribution to Unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Unitholders, likely causing a substantial reduction in the value of our Common Units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our cash available for distribution to our Unitholders. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present United States federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider substantive changes to the existing United States federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for United States federal income tax purposes.

In addition, on January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code of 1986, as amended (the "Final Regulations") were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect our ability to be treated as a partnership for United States federal income tax purposes.

However, any modification to the United States federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for United States federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any similar or future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

If the IRS contests the federal income tax positions we take, the market for our Common Units may be adversely affected and the costs of any such contest will reduce cash available for distributions to our Unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our Common Units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne by us reducing the cash available for distribution to our Unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our Unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each Unitholder and former Unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our Unitholders and former Unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current Unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such Unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our Unitholders might be substantially reduced. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

Unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which will be different in amount than the cash we distribute, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that result from that income.

Tax gain or loss on disposition of our Common Units could be more or less than expected.

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions to our unitholders in excess of the total net taxable income the unitholder was allocated for a unit, which decreased their tax basis in that unit, will, in effect, become taxable income to our unitholders if the common unit is sold at a price greater than their tax basis in that common unit, even if the price they receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if our unitholders sell their units, they may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to Unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be “unrelated business taxable income” and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our units.

Non-United States Unitholders will be subject to United States taxes and withholding with respect to their income and gain from owning our units.

Non-United States unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a United States trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a United States trade or business. As a result, distributions to a Non-United States unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-United States unitholder who sells or otherwise disposes of a unit will also be subject to United States federal income tax on the gain realized from the sale or disposition of that unit.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-United States unitholder's sale or exchange of an interest in a partnership that is engaged in a United States trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-United States unitholders should consult a tax advisor before investing in our units.

We have subsidiaries that will be treated as corporations for federal income tax purposes and subject to corporate-level income taxes.

Even though we (as a partnership for United States federal income tax purposes) are not subject to United States federal income tax, some of our operations are currently conducted through subsidiaries that are organized as corporations for United States federal income tax purposes. The taxable income, if any, of subsidiaries that are treated as corporations for United States federal income tax purposes, is subject to corporate-level United States federal income taxes, which may reduce the cash available for distribution to us and, in turn, to our Unitholders. If the IRS or other state or local jurisdictions were to successfully assert that these corporations have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, the cash available for distribution could be further reduced. The income tax return filings positions taken by these corporate subsidiaries require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite our belief that the income tax return positions taken by these subsidiaries are fully supportable, certain positions may be successfully challenged by the IRS, state or local jurisdictions.

We treat each purchaser of Common Units as having the same tax benefits without regard to the actual Common Units purchased. The IRS may challenge this treatment, which could result in a Unitholder owing more tax and may adversely affect the value of the Common Units.

Because we cannot match transferors and transferees of Common Units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our Unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of Common Units and could have a negative impact on the value of our Common Units or result in audit adjustments to tax returns of our Unitholders. Moreover, because we have subsidiaries that are organized as C corporations for federal income tax purposes which own units in us, a successful IRS challenge could result in this subsidiary having more tax liability than we anticipate and, therefore, reduce the cash available for distribution to our partnership and, in turn, to our Unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge aspects of our proration method, and, if successful, we would be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month (the "Allocation Date"), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

A Unitholder whose units are the subject of a securities loan (e.g. a loan to a "short seller") to cover a short sale of units may be considered as having disposed of those units. If so, the Unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a Unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the Unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the Unitholder and any cash distributions received by the Unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies in determining Unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to such assets to the capital accounts of our unitholders and our general partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourselves using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of our common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain on the sale of common units by our unitholders and could have a negative impact on the value of our common units or result in audit adjustments to the tax returns of our unitholders without the benefit of additional deductions.

Unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our units.

In addition to federal income taxes, the Unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions. We currently own property or conduct business in many states, most of which impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or corporate income tax. Further, Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each Unitholder to file all federal, state and local tax returns.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, our unitholders are entitled to a deduction for the interest we have paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. Although the interest limitation does not apply to certain regulated pipeline businesses, application of the interest limitation to tiered businesses like ours that hold interests in regulated and unregulated businesses is not clear. Pending further guidance specific to this issue, we have not yet determined the impact the limitation could have on our unitholders' ability to deduct our interest expense, but it is possible that our unitholders' interest expense deduction will be limited.

Treatment of distributions on our Series A Preferred Units and Series B Preferred Units as guaranteed payments for the use of capital creates a different tax treatment for the holders of Series A Preferred Units and Series B Preferred Units than the holders of our common units and such distributions may not be eligible for the 20% deduction for qualified publicly traded partnership income.

The tax treatment of distributions on our Series A Preferred Units and our Series B Preferred Units is uncertain. We will treat each of the holders of the Series A Preferred Units and Series B Preferred Units as partners for tax purposes and will treat distributions on the Series A Preferred Units and the Series B Preferred Units as guaranteed payments for the use of capital that will generally be taxable to each of the holders of Series A Preferred Units and Series B Preferred Units as ordinary income. Holders of our Series A Preferred Units or Series B Preferred Units will recognize taxable income from the accrual of such a guaranteed payment (even in the absence of a contemporaneous cash distribution). Otherwise, except in the case of our liquidation, the holders of Series A Preferred Units and Series B Preferred Units are generally not anticipated to share in our items of income, gain, loss or deduction, nor will we allocate any share of our nonrecourse liabilities to the holders of Series A Preferred Units and the Series B Preferred Units. If the Series A Preferred Units and Series B Preferred Units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to each of the holders of Series A Preferred Units and Series B Preferred Units.

Although we expect that much of the income we earn is generally eligible for the 20% deduction for qualified publicly traded partnership income, it is uncertain whether a guaranteed payment for the use of capital may constitute an allocable or distributive share of such income. As a result the guaranteed payment for use of capital received by our Series A Preferred Units and Series B Preferred Units may not be eligible for the 20% deduction for qualified publicly traded partnership income.

A holder of Series A Preferred Units or Series B Preferred Units will be required to recognize gain or loss on a sale of Series A

Preferred Units or Series B Preferred Units, as applicable, equal to the difference between the amount realized by such holder and such holder's tax basis in the Series A Preferred Units or Series B Preferred Units, as applicable, sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such Series A Preferred Units or Series B Preferred Units, as applicable. Subject to general rules requiring a blended basis among multiple partnership interests, the tax basis of a Series A Preferred Unit or Series B Preferred Unit, as applicable, will generally be equal to the sum of the cash and the fair market value of other property paid by the holder of such Series A Preferred Units or Series B Preferred Units, as applicable, to acquire such Series A Preferred Unit or Series B Preferred Unit, as applicable. Gain or loss recognized by a holder of Series A Preferred Units or Series B Preferred Units on the sale or exchange of a Series A Preferred Unit or Series B Preferred Unit, as applicable, held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of Series A Preferred Units and Series B Preferred Units will generally not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Investment in the Series A Preferred Units or the Series B Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts, and non-United States persons raises issues unique to them. The treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain and such payments may be treated as unrelated business taxable income for federal income tax purposes. Distributions to non-United States holders of Series A Preferred Units and Series B Preferred Units will be subject to withholding taxes. If the amount of withholding exceeds the amount of United States federal income tax actually due, non-United States holders of Series A Preferred Units and Series B Preferred Units may be required to file United States federal income tax returns in order to seek a refund of such excess.

All holders of our Series A Preferred Units and Series B Preferred Units are urged to consult a tax advisor with respect to the consequences of owning our Series A Preferred Units and Series B Preferred Units.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in "Item 1. Business." In addition, we own office buildings for our executive offices in Dallas, Texas and office buildings in Newton Square, Pennsylvania and Houston, Texas and San Antonio, Texas. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

We believe that we have satisfactory title to or valid rights to use all of our material properties. Although some of our properties are subject to liabilities and leases, liens for taxes not yet due and payable, encumbrances securing payment obligations under

non-competition agreements and immaterial encumbrances, easements and restrictions, we do not believe that any such burdens will materially interfere with our continued use of such properties in our business, taken as a whole. In addition, we believe that we have, or are in the process of obtaining, all required material approvals, authorizations, orders, licenses, permits, franchises and consents of, and have obtained or made all required material registrations, qualifications and filings with, the various state and local government and regulatory authorities which relate to ownership of our properties or the operations of our business.

Substantially all of our pipelines, which are described in "Item 1. Business," are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, properties on which our pipelines were built were purchased in fee. We also own and operate multiple natural gas and NGL storage facilities and own or lease other processing, treating and conditioning facilities in connection with our midstream operations.

ITEM 3. LEGAL PROCEEDINGS

Sunoco, Inc. and/or Sunoco, Inc. (R&M), (now known as Sunoco (R&M), LLC) along with other members of the petroleum industry, are defendants in lawsuits alleging MTBE contamination of groundwater. The plaintiffs, state-level governmental entities, assert product liability claims and additional claims including nuisance, trespass, negligence, violation of environmental laws, and/or deceptive business practices. The plaintiffs seek to recover compensatory damages, and in some cases also seek natural resource damages, injunctive relief, punitive damages, and attorneys' fees.

As of December 31, 2017, Sunoco, Inc. is a defendant in seven cases, including one case each initiated by the States of Maryland, New Jersey, Vermont, Rhode Island, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. The actions brought by the State of Maryland and Commonwealth of Pennsylvania have also named as defendants Energy Transfer Partners, L.P., ETP Holdco Corporation, and Sunoco Partners Marketing & Terminals, L.P. Four of these cases are pending in a multidistrict litigation proceeding in a New York federal court; one is pending in federal court in Rhode Island, one is pending in state court in Vermont, and one is pending in state court in Maryland.

Sunoco, Inc. and Sunoco, Inc. (R&M) have reached a settlement with the State of New Jersey. The Court approved the Judicial Consent Order on December 5, 2017. Dismissal of the case against Sunoco, Inc. and Sunoco, Inc. (R&M) is expected shortly. The Maryland complaint was filed in December 2017 but was not served until January 2018.

It is reasonably possible that a loss may be realized in the remaining cases; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. An adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any such adverse determination occurs, but such an adverse determination likely would not have a material adverse effect on the Partnership's consolidated financial position.

In January 2012, we experienced a release on our products pipeline in Wellington, Ohio. In connection with this release, the PHMSA issued a Corrective Action Order under which we are obligated to follow specific requirements in the investigation of the release and the repair and reactivation of the pipeline. This PHMSA Corrective Action Order was closed via correspondence dated November 4, 2016. No civil penalties were associated with the PHMSA Order. We also entered into an Order on Consent with the EPA regarding the environmental remediation of the release site. All requirements of the Order on Consent with the EPA have been fulfilled and the Order has been satisfied and closed. We have also received a "No Further Action" approval from the Ohio EPA for all soil and groundwater remediation requirements. In May 2016, we received a proposed penalty from the EPA and DOJ associated with this release, and continues to work with the involved parties to bring this matter to closure. The timing and outcome of this matter cannot be reasonably determined at this time. However, we do not expect there to be a material impact to our results of operations, cash flows or financial position.

In October 2016, the PHMSA issued a Notice of Probable Violation ("NOPVs") and a Proposed Compliance Order ("PCO") related to our West Texas Gulf pipeline in connection with repairs being carried out on the pipeline and other administrative and procedural findings. The proposed penalty is in excess of $100,000. The case went to hearing in March 2017 and remains open with PHMSA. We do not expect there to be a material impact to our results of operations, cash flows or financial position.

In April 2016, the PHMSA issued a NOPV, PCO and Proposed Civil Penalty related to certain procedures carried out during construction of our Permian Express 2 pipeline system in Texas. The proposed penalties are in excess of $100,000. The case went to Hearing in November 2016 and remains open with PHMSA. We do not expect there to be a material impact to our results of operations, cash flows or financial position.

In July 2016, the PHMSA issued a NOPV and PCO to our West Texas Gulf pipeline in connection with inspection and maintenance activities related to a 2013 incident on our crude oil pipeline near Wortham, Texas. The proposed penalties are in excess of $100,000. The case went to hearing in March 2017 and remains open with PHMSA. We do not expect there to be a material impact to our results of operations, cash flows, or financial position.

In August 2017, the PHMSA issued a NOPV and a PCO in connection with alleged violations on our Nederland to Kilgore pipeline in Texas. The case remains open with PHMSA and the proposed penalties are in excess of $100,000. We do not expect there to be a material impact to our results of operations, cash flows or financial position.

In December 2016, we received multiple Notice of Violations ("NOVs") from the Delaware County Regional Water Quality Control Authority ("DELCORA") in connection with a discharge at our Marcus Hook Industrial Complex ("MHIC") in July 2016. We also entered in a Consent Order and Agreement from the Pennsylvania Department of Environmental Protection ("PADEP") related to our tank inspection plan at MHIC. These actions propose penalties in excess of $100,000, and we are currently in discussions with the PADEP and DELCORA to resolve these matters. The timing or outcome of these matters cannot be reasonably determined at this time; however, we do not expect there to be a material impact to our results of operations, cash flows, or financial position.

The Ohio Environmental Protection Agency ("Ohio EPA") has alleged that various environmental violations have occurred during construction of the Rover pipeline project. The alleged violations include inadvertent returns of drilling muds and fluids at horizontal directional drilling ("HDD") locations in Ohio that affected waters of the State, storm water control violations, improper disposal of spent drilling mud containing diesel fuel residuals, and open burning. The alleged violations occurred from April 2017 to July 2017. Although Rover has successfully completed clean-up mitigation for the alleged violations to Ohio EPA's satisfaction, the Ohio EPA has proposed penalties of approximately $2.6 million in connection with the alleged violations and is seeking certain injunctive relief. The Ohio Attorney General filed a complaint in the Court of Common Pleas of Stark County, Ohio to obtain these remedies and that case remains pending and is in the early stages. The timing or outcome of this matter cannot be reasonably determined at this time; however, we do not expect there to be a material impact to our results of operations, cash flows or financial position.

In addition, on May 10, 2017, the FERC prohibited Rover from conducting HDD activities at 27 sites in Ohio. On July 31, 2017, the FERC issued an independent third party assessment of what led to the release at the Tuscarawas River site and what Rover can do to prevent reoccurrence once the HDD suspension is lifted. Rover notified the FERC of its intention to implement the suggestions in the assessment and to implement additional voluntary protocols. In response, FERC authorized Rover to resume HDD activities at certain sites. On January 24, 2018, FERC ordered Rover to cease HDD activities at the Tuscarawas River HDD site pending FERC review of additional information from Rover. Rover continues to correspond with regulators regarding drilling operations and drilling plans at the HDD sites where Rover has not yet completed HDD activities, including the Tuscarawas River HDD site. The timing or outcome of this matter cannot be reasonably determined at this time. We do not expect there to be a material impact to its results of operations, cash flows or financial position.

In late 2016, FERC Enforcement Staff began a non-public investigation of Rover's demolition of the Stoneman House, a potential historic structure, in connection with Rover's application for permission to construct a new interstate natural gas pipeline and related facilities. Rover and ETP are cooperating with the investigation. In March and April 2017, Enforcement Staff provided Rover its non-public preliminary findings regarding its investigation. The company disagrees with those findings and intends to vigorously defend against any potential penalty. Given the stage of the proceeding, and the non-public nature of the preliminary findings and investigation, ETP is unable at this time to provide an assessment of the potential outcome or range of potential liability, if any.

On July 25, 2017, the Pennsylvania Environmental Hearing Board ("EHB") issued an order to SPLP to cease HDD activities in Pennsylvania related to the Mariner East 2 project. The EHB issued the order in response to a complaint filed by environmental groups against SPLP and the Pennsylvania Department of Environmental Protection ("PADEP"). On August 10, 2017 the parties reached a final settlement requiring that SPLP reevaluate the design parameters of approximately 26 drills on the Mariner East 2 project and approximately 43 drills on the Mariner East 2X project. The settlement agreement also provides a defined framework for approval by PADEP for these drills to proceed after reevaluation. Additionally, the settlement agreement requires modifications to several of the HDD plans that are part of the PADEP permits. Those modifications have been completed and agreed to by the parties and the reevaluation of the drills has been initiated by the company.

In addition, on June 27, 2017 and July 25, 2017, the PADEP entered into a Consent Order and Agreement with SPLP regarding inadvertent returns of drilling fluids at three HDD locations in Pennsylvania related to the Mariner East 2 project. Those agreements require SPLP to cease HDD activities at those three locations until PADEP reauthorizes such activities and to submit a corrective action plan for agency review and approval. SPLP is working to fulfill the requirements of those agreements and has been authorized by PADEP to resume drilling at one of the three locations.

On January 3, 2018, PADEP issued an Administrative Order to Sunoco Pipeline L.P. directing that work on the Mariner East 2 and 2X pipelines be stopped. The Administrative Order detailed alleged violations of the permits issued by PADEP in February of 2017, during the construction of the project. Sunoco Pipeline L.P. began working with PADEP representatives immediately after the Administrative Order was issued to resolve the compliance issues. Those compliance issues could not be fully resolved by the deadline to appeal the Administrative Order, so Sunoco Pipeline L.P. took an appeal of the Administrative Order to the Pennsylvania Environmental Hearing Board on February 2, 2018. On February 8, 2018, Sunoco Pipeline L.P. entered into a Consent Order and Agreement with PADEP that (1) withdraws the Administrative Order; (2) establishes requirements for compliance with permits on a going forward basis; (3) resolves the non-compliance alleged in the Administrative Order; and (4) conditions restart of work on an agreement by Sunoco Pipeline L.P. to pay a $12.6 million civil penalty to the Commonwealth of Pennsylvania. In the Consent Order and agreement, Sunoco Pipeline L.P. admits to the factual allegations, but does not admit to the conclusions of law that were made by PADEP. PADEP also found in the Consent Order and Agreement that Sunoco Pipeline L.P. had adequately addressed the issues raised in the Administrative Order and demonstrated an ability to comply with the permits. Sunoco Pipeline L.P. concurrently filed a request to the Pennsylvania Environmental Hearing Board to discontinue the appeal of the Administrative Order. That request was granted on February 8, 2018.

On January 18, 2018, PHMSA issued a NOPV and a Proposed Civil Penalty in connection with alleged violations on our East Boston jet fuel pipeline in Boston, MA. The case remains open with PHMSA and the proposed penalties are in excess of $100,000. We do not expect there to be a material impact to its results of operations, cash flows or financial position.

On January 18, PHMSA issued a NOPV and a PCO in connection with alleged violations on Eastern Area refined products and crude oil pipeline system in the States of MI, OH, PA, NY, NJ and DE. The case remains open with PHMSA and the proposed penalties are in excess of $100,000. We do not expect there to be a material impact to its results of operations, cash flows or financial position.

Additionally, we have received notices of violations and potential fines under various federal, state and local provisions relating to the discharge of materials into the environment or protection of the environment. While we believe that even if any one or more of the environmental proceedings listed above were decided against us, it would not be material to our financial position, results of operations or cash flows, we are required to report governmental proceedings if we reasonably believe that such proceedings will result in monetary sanctions in excess of $100,000.

For a description of other legal proceedings, see Note 11 to our consolidated financial statements included in “Item 8. Financial Statements and Supplementary Data.”

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Price of and Distributions on the Common Units and Related Unitholder Matters

Our Common Units are listed on the NYSE under the symbol "ETP." The following table sets forth, for the periods indicated, the high and low sales prices per Common Unit, as reported on the NYSE Composite Tape, and the amount of cash distributions paid per Common Unit for the periods indicated.

	Price Range		
	High	Low	Cash Distribution[1]
Fiscal Year 2017			
Fourth Quarter	$ 18.75	$ 15.71	$ 0.5650
Third Quarter	21.68	17.85	0.5650
Second Quarter	24.71	18.31	0.5500
First Quarter	26.73	22.90	0.5350
Fiscal Year 2016			
Fourth Quarter	$ 28.61	$ 22.07	$ 0.5200
Third Quarter	31.49	26.88	0.5100
Second Quarter	29.77	22.63	0.5000
First Quarter	28.72	15.43	0.4890

(1) Distributions are shown in the quarter with respect to which they relate. Please see "Cash Distribution Policy" below for a discussion of our policy regarding the payment of distributions.

Description of Units

Common Units

As of February 16, 2018, there were approximately 506,829 individual Common Unitholders, which includes Common Units held in street name. The Common Units are entitled to distributions of Available Cash as described below under "Cash Distribution Policy."

Class E Units

There are currently 8.9 million Class E Units outstanding, all of which are currently owned by HHI. The Class E Units generally do not have any voting rights. The Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. As the Class E Units are owned by a wholly-owned subsidiary, the cash distributions on those units are eliminated in our consolidated financial statements. Although no plans are currently in place, management may evaluate whether to retire the Class E Units at a future date.

Class G Units

There are currently 90.7 million Class G Units outstanding, all of which are held by a wholly-owned subsidiary of the Partnership. The Class G Units generally do not have any voting rights. The Class G Units are entitled to aggregate cash distributions equal to 35% of the total amount of cash generated by us and our subsidiaries, other than ETP Holdco, and available for distribution, up to a maximum of $3.75 per Class G Unit per year. Allocations of depreciation and amortization to the Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss. These units are reflected as treasury units in the consolidated financial statements.

Class I Units

The Class I Units are held by ETE and are not currently entitled to any distributions.

Class J Units

On July 27, 2016, the Partnership issued to ETE an aggregate amount of 180 Class J units representing limited partner interests in the Partnership (the "Class J Units"). A portion of the additional Class J Units will be issued during each of 2016, 2017 and 2018. Each Class J Unit is entitled to an allocation of $10.0 million of depreciation, amortization, depletion or other form of cost-recovery during the year in which such Class J Unit was issued; no Class J Unit is entitled to any other allocations of depreciation, amortization, depletion or other cost-recovery in any other year, and such units are not entitled to any cash distributions at any time. In exchange for the issuance of the Class J Units, ETP's partnership agreement was amended to further reduce incentive distributions commencing with the quarter ended June 30, 2016 and ending with the quarter ending December 31, 2017, in an aggregate amount of $720 million.

Class K Units

On December 29, 2016, the Partnership issued to certain of its indirect subsidiaries, in exchange for cash contributions and the exchange of outstanding common units representing limited partner interests in the Partnership, Class K Units, each of which is entitled to a quarterly cash distribution of $0.67275 per Class K Unit prior to ETP making distributions of available cash to any class of units, excluding any cash available distributions or dividends or capital stock sales proceeds received by ETP from ETP Holdco. If the Partnership is unable to pay the Class K Unit quarterly distribution with respect to any quarter, the accrued and unpaid distributions will accumulate until paid and any accumulated balance will accrue 1.5% per annum until paid. As of December 31, 2017, a total of 101.5 million Class K Units were held by wholly-owned subsidiaries of ETP.

General Partner Interest

As of December 31, 2017, our General Partner owned an approximate 0.3% general partner interest in us and the holders of Common Units, Class E, Class G, Class I, Class J, and Class K Units collectively owned a 99.7% limited partner interest in us.

Incentive Distribution Rights

IDRs represent the contractual right, pursuant to the terms of our partnership agreement, of our general partner to receive a specified percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. Please read "Distributions of Available Cash from Operating Surplus" below.

ETP Preferred Units

In November 2017, ETP issued 950,000 of its 6.250% Series A Preferred Units at a price of $1,000 per unit, and 550,000 of its 6.625% Series B Preferred Units at a price of $1,000 per unit.

Distributions on the Series A Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, February 15, 2023, at a rate of 6.250% per annum of the stated liquidation preference of $1,000. On and after February 15, 2023, distributions on the Series A Preferred Units will accumulate at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.028% per annum. The Series A Preferred Units are redeemable at ETP's option on or after February 15, 2023 at a redemption price of $1,000 per Series A Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Distributions on the Series B Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, February 15, 2028, at a rate of 6.625% per annum of the stated liquidation preference of $1,000. On and after February 15, 2028, distributions on the Series B Preferred Units will accumulate at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.155% per annum. The Series B Preferred Units are redeemable at ETP's option on or after February 15, 2028 at a redemption price of $1,000 per Series B Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Cash Distribution Policy

General. We will distribute all of our "Available Cash" to our Unitholders and our General Partner within 45 days following the end of each fiscal quarter.

Definition of Available Cash. Available Cash is defined in our Partnership Agreement and generally means, with respect to any calendar quarter, all cash on hand at the end of such quarter:

- Less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to:
  - provide for the proper conduct of our business;

  - comply with applicable law and/or debt instrument or other agreement (including reserves for future capital expenditures and for our future capital needs); or
  - provide funds for distributions to Unitholders and our General Partner in respect of any one or more of the next four quarters.
- Plus all cash on hand on the date of determination of Available Cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our credit facilities and in all cases used solely for working capital purposes or to pay distributions to partners.

Available Cash is more fully defined in our Partnership Agreement, which is an exhibit to this report.

Operating Surplus and Capital Surplus

General. All cash distributed to our Unitholders is characterized as either "operating surplus" or "capital surplus." We distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus. Our operating surplus for any period generally means:

- our cash balance on the closing date of our initial public offering; plus
- $15 million (as described below); plus
- all of our cash receipts since the closing of our initial public offering, excluding cash from interim capital transactions such as borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus
- our working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; plus
- legacy ETP's operating surplus at the time of closing of the merger between legacy ETP and the Partnership in April 2017; less
- all of our operating expenditures after the closing of our initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures; less
- the amount of our cash reserves that our General Partner deems necessary or advisable to provide funds for future operating expenditures.

Definition of Capital Surplus. Generally, our capital surplus will be generated only by:

- borrowings other than working capital borrowings;
- sales of our debt and equity securities; and
- sales or other disposition of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

Characterization of Cash Distributions. We will treat all Available Cash distributed as coming from operating surplus until the sum of all Available Cash distributed since we began operations equals the operating surplus as of the most recent date of determination of Available Cash. We will treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As defined in our Partnership Agreement, operating surplus includes $25 million (consisting of $15 million related to the legacy Sunoco Logistics operating surplus and $10 million related to the legacy ETP operating surplus) in addition to our cash balance on the closing date of our initial public offering, cash receipts from our operations and cash from working capital borrowings. This amount does not reflect actual cash on hand that is available for distribution to our Unitholders. Rather, it is a provision that enables us, if we choose, to distribute as operating surplus up to $25 million of cash we receive in the future from non-operating sources, such as asset sales, issuances of securities, and long-term borrowings, that would otherwise be distributed as capital surplus. We have not made, and we anticipate that we will not make, any distributions from capital surplus.

Distributions of Available Cash from Operating Surplus

The terms of our partnership agreement require that we make cash distributions with respect to each calendar quarter within 45 days following the end of each calendar quarter. As discussed above under "Description of Units – Class K Units" and "Description of Units – ETP Preferred Units," the Class K Units, the Series A Preferred Units and the Series B Preferred Units are entitled to distributions from ETP prior to ETP making quarterly distributions of Available Cash to other classes of units. We are required to make distributions of remaining Available Cash from operating surplus for any quarter in the following manner:

- ***First***, 100% to all Common Unitholders, Class E Unitholders and Class G Unitholders and the general partner, in accordance with their percentage interests, until each Common Unit has received $0.075 per unit for such quarter (the "minimum quarterly distribution");
- ***Second***, 100% to all Common Unitholders, Class E Unitholders and Class G Unitholders and the general partner, in accordance with their respective percentage interests, until each Common Unit has received $0.0833 per unit for such quarter (the "first target distribution");
- ***Third***, (i) to the general partner in accordance with its percentage interest, (ii) 13% to the holders of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class G Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs, until each Common Unit has received $0.0958 per unit for such quarter (the "second target distribution");
- ***Fourth***, (i) to the general partner in accordance with its percentage interest, (ii) 35% to the holders of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class G Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs, until each Common Unit has received $0.2638 per unit for such quarter (the "third target distribution"); and
- ***Fifth***, thereafter, (i) to the general partner in accordance with its percentage interest, (ii) 48% to the holder of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class G Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs.

The allocation of distributions among the Common, Class E and Class G Unitholders and the General Partner is based on their respective interests as of the record date for such distributions.

Notwithstanding the foregoing, the distributions on each Class E unit may not exceed $1.41 per year and distributions on each Class G unit may not exceed $3.75 per year. In addition, the distributions to the holders of the incentive distribution rights will not exceed the amount the holders of the incentive distributions rights would otherwise receive if the available cash for distribution were reduced to the extent it constitutes amounts previously distributed with respect to the Class G units.

The incentive distributions described above do not reflect the impact of IDR subsidies previously agreed to by ETE in connection with previous transactions, as described below under "IDR Subsidies."

Distributions of Available Cash from Capital Surplus

We will make distributions of any Available Cash from capital surplus in the following manner:

- ***First***, to all of our Unitholders and to our General Partner, in accordance with their percentage interests, until we distribute for each Common Unit, an amount of available cash from capital surplus equal to our initial public offering price; and
- ***Thereafter***, we will make all distributions of Available Cash from capital surplus as if they were from operating surplus.

Our Partnership Agreement treats a distribution of capital surplus as the repayment of the initial unit price from the initial public offering, which is a return of capital. The initial public offering price per Common Unit less any distributions of capital surplus per unit is referred to as the "unrecovered capital."

If we combine our units into fewer units or subdivide our units into a greater number of units, we will proportionately adjust our minimum quarterly distribution; our target cash distribution levels; and our unrecovered capital. For example, if a two-for-one split of our Common Units should occur, our unrecovered capital would be reduced to 50% of the initial level. We will not make any adjustment by reason of our issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted in a manner that causes us to become taxable as a corporation or otherwise subject to additional taxation as an entity for federal, state or local income tax purposes, under the terms of the Partnership Agreement, we can reduce our minimum quarterly distribution and the target cash distribution levels by multiplying the same by one minus the sum of the highest marginal federal corporate income tax rate that could apply and any increase in the effective overall state and local income tax rates.

IDR Subsidies and Other Distribution Adjustments

As described above, our partnership agreement requires certain incentive distributions to the holders of the IDRs.

In connection with previous transactions, ETE has agreed to relinquish its right to the following amounts of incentive distributions in future periods:

	Total Year
2018	$ 153
2019	128
Each year beyond 2019	33

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

Securities Authorized for Issuance Under Equity Compensation Plans

For information on the securities authorized for issuance under ETP's equity compensation plans, see "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters."

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and the accompanying notes thereto included elsewhere in this report. The amounts in the table below, except per unit data, are in millions.

As discussed in Note 1 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" the merger of legacy ETP and legacy Sunoco Logistics in April 2017 resulted in legacy ETP being treated as the surviving entity from an accounting perspective. Accordingly, the selected financial data below reflects the consolidated financial information of legacy ETP, except otherwise noted.

The historical common units, cash distributions per unit and net income (loss) per limited partner unit amounts presented in these consolidated financial statements have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange in connection with the Sunoco Logistics Merger.

As discussed in Note 2 to the Partnership's consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data," in the fourth quarter of 2017, the Partnership changed its accounting policy related to certain inventories. Certain crude oil, refined product and NGL inventories were changed from last-in, first-out ("LIFO") method to the weighted average cost method. These changes have been applied retrospectively to all periods presented, and the prior period amounts reflected below have been adjusted from those amounts previously reported.

	Years Ended December 31,				
	2017	2016*	2015*	2014*	2013*
Statement of Operations Data:					
Total revenues	$ 29,054	$ 21,827	$ 34,292	$ 55,475	$ 48,335
Operating income	2,397	1,761	2,227	2,393	1,655
Income from continuing operations	2,501	583	1,489	1,185	749
Net income (loss) per Common Unit	0.94	(1.38)	(0.07)	1.16	(0.10)
Diluted net income (loss) per Common Unit	0.93	(1.38)	(0.08)	1.15	(0.10)
Cash distributions per common unit [1]	2.22	2.02	1.79	1.50	1.23
Cash distributions per common unit - Legacy ETP [2]	N/A	2.81	2.77	2.57	2.41
Balance Sheet Data (at period end):					
Total assets	77,965	70,105	65,128	62,505	49,937
Long-term debt, less current maturities	32,687	31,741	28,553	24,831	19,761
Total equity	34,151	26,441	26,986	25,298	18,731
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis)	429	368	485	444	391
Growth (accrual basis)	5,472	5,442	7,682	5,050	2,936
Cash paid for acquisitions	264	1,227	804	2,367	1,737

* As adjusted for the change in accounting policy related to inventory valuation, as discussed above.

(1) Represents cash distributions of legacy Sunoco Logistics through the closing of the Sunoco Logistics Merger and ETP thereafter.

(2) Represents cash distributions on legacy ETP common units through the closing of the Sunoco Logistics Merger.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Tabular dollar and unit amounts, except per unit data, are in millions)

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included in "Item 8. Financial Statements and Supplementary Data" of this report. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in "Item 1A. Risk Factors" included in this report.

References to "we," "us," "our," the "Partnership" and "ETP" shall mean Energy Transfer Partners, L.P. and its subsidiaries.

Overview

The primary activities and operating subsidiaries through which we conduct those activities are as follows:

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage; and
  - interstate natural gas transportation and storage.
- Crude oil, NGLs and refined product transportation, terminalling services and acquisition and marketing activities, as well as NGL storage and fractionation services.

Recent Developments

January 2018 Sunoco LP Common Units Repurchase

In February 2018, after the record date for Sunoco LP's fourth quarter 2017 cash distributions, Sunoco LP repurchased 17,286,859 Sunoco LP common units owned by ETP for aggregate cash consideration of approximately $540 million. ETP used the proceeds from the sale of the Sunoco LP common units to repay amounts outstanding under its revolving credit facility.

CDM Contribution Agreement

In January 2018, ETP entered into a contribution agreement ("CDM Contribution Agreement") with ETP GP, ETC Compression, LLC, USAC and ETE, pursuant to which, among other things, ETP will contribute to USAC and USAC will acquire from ETP all of the issued and outstanding membership interests of CDM and CDM E&T for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 common units representing limited partner interests in USAC ("USAC Common Units"), with a value of approximately $335 million, (ii) 6,397,965 units of a newly authorized and established class of units representing limited partner interests in USAC ("Class B Units"), with a value of approximately $112 million and (iii) an amount in cash equal to $1.225 billion, subject to certain adjustments. The Class B Units that ETP will receive will be a new class of partnership interests of USAC that will have substantially all of the rights and obligations of a USAC Common Unit, except the Class B Units will not participate in distributions made prior to the one year anniversary of the closing date of the CDM Contribution Agreement (such date, the "Class B Conversion Date") with respect to USAC Common Units. On the Class B Conversion Date, each Class B Unit will automatically convert into one USAC Common Unit. The transaction is expected to close in the first half of 2018, subject to customary closing conditions.

In connection with the CDM Contribution Agreement, ETP entered into a purchase agreement with ETE, Energy Transfer Partners, L.L.C. (together with ETE, the "GP Purchasers"), USAC Holdings and, solely for certain purposes therein, R/C IV USACP Holdings, L.P., pursuant to which, among other things, the GP Purchasers will acquire from USAC Holdings (i) all of the outstanding limited liability company interests in USA Compression GP, LLC, the general partner of USAC ("USAC GP"), and (ii) 12,466,912 USAC Common Units for cash consideration equal to $250 million.

ETP Credit Facilities

On December 1, 2017 the Partnership entered into a five-year, $4.0 billion unsecured revolving credit facility, which matures December 1, 2022 (the "ETP Five-Year Facility") and a $1.0 billion 364-day revolving credit facility that matures on November 30, 2018 (the "ETP 364-Day Facility") (collectively, the "ETP Credit Facilities").

ETP Preferred Units

In November 2017, ETP issued 950,000 of its 6.250% Series A Preferred Units at a price of $1,000 per unit, and 550,000 of its 6.625% Series B Preferred Units at a price of $1,000 per unit. See additional information included in "Description of Units – ETP

Preferred Units" in "Item 5. Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities."

ETP Senior Notes Offering

In September 2017, Sunoco Logistics Partners Operations L.P., a subsidiary of ETP, issued $750 million aggregate principal amount of 4.00% senior notes due 2027 and $1.50 billion aggregate principal amount of 5.40% senior notes due 2047. The $2.22 billion net proceeds from the offering were used to redeem all of the $500 million aggregate principal amount of ETLP's 6.5% senior notes due 2021, to repay borrowings outstanding under the Sunoco Logistics Credit Facility and for general partnership purposes.

August 2017 Units Offering

In August 2017, the Partnership issued 54 million ETP common units in an underwritten public offering. Net proceeds of $997 million from the offering were used by the Partnership to repay amounts outstanding under its revolving credit facilities, to fund capital expenditures and for general partnership purposes.

Rover Contribution Agreement

In October 2017, ETP completed the previously announced contribution transaction with a fund managed by Blackstone Energy Partners and Blackstone Capital Partners, pursuant to which ETP exchanged a 49.9% interest in the holding company that owns 65% of the Rover pipeline ("Rover Holdco"). As a result, Rover Holdco is now owned 50.1% by ETP and 49.9% by Blackstone. Upon closing, Blackstone contributed funds to reimburse ETP for its pro rata share of the Rover construction costs incurred by ETP through the closing date, along with the payment of additional amounts subject to certain adjustments.

PennTex Tender Offer and Limited Call Right Exercise

In June 2017, ETP purchased all of the outstanding PennTex common units not previously owned by ETP for $20.00 per common unit in cash. ETP now owns all of the economic interests of PennTex, and PennTex common units are no longer publicly traded or listed on the NASDAQ.

ETP and Sunoco Logistics Merger

In April 2017, Energy Transfer Partners, L.P. and Sunoco Logistics completed a merger transaction (the "Sunoco Logistics Merger") in which Sunoco Logistics acquired Energy Transfer Partners, L.P. in a unit-for-unit transaction, with the Energy Transfer Partners, L.P. unitholders receiving 1.5 common units of Sunoco Logistics for each Energy Transfer Partners, L.P. common unit they owned. Under the terms of the merger agreement, Sunoco Logistics' general partner was merged with and into ETP GP, with ETP GP surviving as an indirect wholly-owned subsidiary of ETE.

Permian Express Partners

In February 2017, Sunoco Logistics formed PEP, a strategic joint venture with ExxonMobil. Sunoco Logistics contributed its Permian Express 1, Permian Express 2, Permian Longview and Louisiana Access pipelines. ExxonMobil contributed its Longview to Louisiana and Pegasus pipelines, Hawkins gathering system, an idle pipeline in southern Oklahoma, and its Patoka, Illinois terminal. Assets contributed to PEP by ExxonMobil were reflected at fair value on the Partnership's consolidated balance sheet at the date of the contribution, including $547 million of intangible assets and $435 million of property, plant and equipment.

In July 2017, ETP contributed an approximate 15% ownership interest in Dakota Access and ETCO to PEP, which resulted in an increase in ETP's ownership interest in PEP to approximately 88%. ETP maintains a controlling financial and voting interest in PEP and is the operator of all of the assets. As such, PEP is reflected as a consolidated subsidiary of the Partnership. ExxonMobil's interest in PEP is reflected as noncontrolling interest in the consolidated balance sheets. ExxonMobil's contribution resulted in an increase of $988 million in noncontrolling interest, which is reflected in "Capital contributions from noncontrolling interest" in the consolidated statement of equity.

Bakken Equity Sale

In February 2017, Bakken Holdings Company LLC, an entity in which ETP indirectly owns a 100% membership interest, sold a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by MPLX LP and Enbridge Energy Partners, L.P., for $2.00 billion in cash. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access and ETCO. The remaining 25% of each of Dakota Access and ETCO is owned by wholly-owned subsidiaries of Phillips 66. ETP continues to consolidate Dakota Access and ETCO subsequent to this transaction.

General

Our primary objective is to increase the level of our distributable cash flow to our Unitholders over time by pursuing a business strategy that is focused on growing our businesses through, among other things, pursuing construction and expansion opportunities and acquiring strategic operations and businesses or assets as demonstrated by our recent acquisitions and organic growth projects. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from our operations.

During the past several years, we have been successful in completing several transactions that have significantly increased our distributable cash flow. We have also made, and are continuing to make, significant investments in internal growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will provide additional distributable cash flow to our Partnership for years to come. Lastly, we have established and executed on cost control measures to drive cost savings across our operations to generate additional distributable cash flow.

Our principal operations as of December 31, 2017 included the following segments:

- Intrastate transportation and storage – Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through our pipelines on an interruptible basis. Our interruptible or short-term business is generally impacted by basis differentials between delivery points on our system and the price of natural gas. The basis differentials that primarily impact our interruptible business are primarily among receipt points between West Texas to East Texas or segments thereof. When narrow or flat spreads exist, our open capacity may be underutilized and go unsold. Conversely, when basis differentials widen, our interruptible volumes and fees generally increase. The fee structure normally consists of a monetary fee and fuel retention. Excess fuel retained after consumption, if any, is typically sold at market prices. In addition to transport fees, we generate revenue from purchasing natural gas and transporting it across our system. The natural gas is then sold to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System purchases natural gas at the wellhead for transport and selling. Other pipelines with access to West Texas supply, such as Oasis and ET Fuel, may also purchase gas at the wellhead and other supply sources for transport across our system to be sold at market on the east side of our system. This activity allows our intrastate transportation and storage segment to capture the current basis differentials between delivery points on our system or to capture basis differentials that were previously locked in through hedges. Firm capacity long-term contracts are typically not subject to price differentials between shipping locations.

  We also generate fee-based revenue from our natural gas storage facilities by contracting with third parties for their use of our storage capacity. From time to time, we inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, a term used to describe a pricing environment when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. Our earnings from natural gas storage we purchase, store and sell are subject to the current market prices (spot price in relation to forward price) at the time the storage gas is hedged. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market and entering into a financial derivative to lock in the forward sale price. If we designate the related financial derivative as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices whereas the financial derivative is valued using forward natural gas prices. As a result of fair value hedge accounting, we have elected to exclude the spot forward premium from the measurement of effectiveness and changes in the spread between forward natural gas prices and spot market prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related financial derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. If the spread narrows between spot and forward prices, we will record unrealized gains or lower unrealized losses. If the spread widens prior to withdrawal of the gas, we will record unrealized losses or lower unrealized gains.

  As noted above, any excess retained fuel is sold at market prices. To mitigate commodity price exposure, we may use financial derivatives to hedge prices on a portion of natural gas volumes retained. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

  In addition, we use financial derivatives to lock in price differentials between market hubs connected to our assets on a portion of our intrastate transportation system's unreserved capacity. Gains and losses on these financial derivatives are dependent on price differentials at market locations, primarily points in West Texas and East Texas. We account for these derivatives using mark-to-market accounting, and the change in the value of these derivatives is recorded in earnings. During the fourth quarter of 2011, we began using derivatives for trading purposes.

- Interstate transportation and storage – The majority of our interstate transportation and storage revenues are generated through firm reservation charges that are based on the amount of firm capacity reserved for our firm shippers regardless of usage. Tiger, FEP, Transwestern, Panhandle, MEP and Gulf States shippers have made long-term commitments to pay reservation charges for the firm capacity reserved for their use. In addition to reservation revenues, additional revenue sources include interruptible transportation charges as well as usage rates and overrun rates paid by firm shippers based on their actual capacity usage.

- Midstream – Revenue is principally dependent upon the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines as well as the level of natural gas and NGL prices.

  In addition to fee-based contracts for gathering, treating and processing, we also have percent-of-proceeds and keep-whole contracts, which are subject to market pricing. For percent-of-proceeds contracts, we retain a portion of the natural gas and NGLs processed, or a portion of the proceeds of the sales of those commodities, as a fee. When natural gas and NGL prices increase, the value of the portion we retain as a fee increases. Conversely, when prices of natural gas and NGLs decrease, so does the value of the portion we retain as a fee. For wellhead (keep-whole) contracts, we retain the difference between the price of NGLs and the cost of the gas to process the NGLs. In periods of high NGL prices relative to natural gas, our margins increase. During periods of low NGL prices relative to natural gas, our margins decrease or could become negative. Our processing contracts and wellhead purchases in rich natural gas areas provide that we earn and take title to specified volumes of NGLs, which we also refer to as equity NGLs. Equity NGLs in our midstream segment are derived from performing a service in a percent-of-proceeds contract or produced under a keep-whole arrangement.

  In addition to NGL price risk, our processing activity is also subject to price risk from natural gas because, in order to process the gas, in some cases we must purchase it. Therefore, lower gas prices generally result in higher processing margins.

- NGL and refined products transportation and services – Liquids transportation revenue is principally generated from fees charged to customers under dedicated contracts or take-or-pay contracts. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported. Transportation fees are market-based, negotiated with customers and competitive with regional regulated pipelines.

  NGL storage revenues are derived from base storage fees and throughput fees. Base storage fees are based on the volume of capacity reserved, regardless of the capacity actually used. Throughput fees are charged for providing ancillary services, including receipt and delivery, custody transfer, rail/truck loading and unloading fees. Storage contracts may be for dedicated storage or fungible storage. Dedicated storage enables a customer to reserve an entire storage cavern, which allows the customer to inject and withdraw proprietary and often unique products. Fungible storage allows a customer to store specified quantities of NGL products that are commingled in a storage cavern with other customers' products of the same type and grade. NGL storage contracts may be entered into on a firm or interruptible basis. Under a firm basis contract, the customer obtains the right to store products in the storage caverns throughout the term of the contract; whereas, under an interruptible basis contract, the customer receives only limited assurance regarding the availability of capacity in the storage caverns. Revenues are also generated by charging fees for terminalling services for NGLs and refined products and by acquiring and marketing NGLs and refined products. Generally, NGL and refined products purchases are entered into in contemplation of or simultaneously with corresponding sale transactions involving physical deliveries, which enables us to secure a profit on the transaction at the time of purchase.

  Our refined products terminals derive revenues from terminalling fees paid by customers. A fee is charged for receiving products into the terminal and delivering them to trucks, barges, or pipelines. In addition to terminalling fees, our refined products terminals generate revenues by charging customers fees for blending services, including certain ethanol and biodiesel blending, injecting additives, and filtering jet fuel. Our refined products pipelines provide supply to the majority of our refined products terminals, with third-party pipelines and barges supplying the remainder.

  Our refined products acquisition and marketing activities include the acquisition, marketing and selling of bulk refined products such as gasoline products and distillates. These activities utilize our refined products pipeline and terminal assets, as well as third-party assets and facilities. The operating results of our refined products acquisition and marketing activities are dependent on our ability to execute sales in excess of the aggregate cost, and therefore we structure our acquisition and marketing operations to optimize the sources and timing of purchases and minimize the transportation and storage costs. In order to manage exposure to volatility in refined products prices, our policy is to (i) only purchase products for which sales contracts have been executed or for which ready markets exist, (ii) structure sales contracts so that price fluctuations do not materially impact the margins earned, and (iii) not acquire and hold physical inventory, futures contracts or other derivative instruments for the purpose of speculating on commodity price changes. However, we do utilize a hedge program involving swaps, future and other derivative instruments to mitigate the risk associated with unfavorable market movements in the price of refined products. These derivative contracts act as a hedging mechanism against the volatility of prices.

This segment also includes revenues earned from processing and fractionating refinery off-gas. Under these contracts we receive an O-grade stream from cryogenic processing plants located at refineries and fractionate the products into their pure components. We deliver purity products to customers through pipelines and across a truck rack located at the fractionation complex. In addition to revenues for fractionating the O-grade stream, we have percentage-of-proceeds and income sharing contracts, which are subject to market pricing of olefins and NGLs. For percentage-of-proceeds contracts, we retain a portion of the purity NGLs and olefins processed, or a portion of the proceeds from the sales of those commodities, as a fee. When NGLs and olefin prices increase, the value of the portion we retain as a fee increases. Conversely, when NGLs and olefin prices decrease, so does the value of the portion we retain as a fee. Under our income sharing contracts, we pay the producer the equivalent energy value for their liquids, similar to a traditional keep-whole processing agreement, and then share in the residual income created by the difference between NGLs and olefin prices as compared to natural gas prices. As NGLs and olefins prices increase in relation to natural gas prices, the value of the percent we retain as a fee increases. Conversely, when NGLs and olefins prices decrease as compared to natural gas prices, so does the value of the percent we retain as a fee.

- Crude oil transportation and services – Revenues are generated by charging tariffs for transporting crude oil though our pipelines as well as by charging fees for terminalling services at our facilities. Revenues are also generated by acquiring and marketing crude oil. Generally, crude oil purchases are entered into in contemplation of or simultaneously with corresponding sale transactions involving physical deliveries, which enables us to secure a profit on the transaction at the time of purchase.

Trends and Outlook

We continue to evaluate and execute strategies to enhance unitholder value through growth, as well as the integration and optimization of our diversified asset portfolio. We intend to target a minimum distribution coverage ratio of 1.10x, thereby promoting a prudent balance between distribution rate increases and enhanced financial flexibility and strength while maintaining our investment grade ratings. We anticipate significant earnings growth in 2018 from the completion of our project backlog. We also continue to seek asset optimization opportunities through strategic transactions among us and our subsidiaries and/or affiliates, and we expect to continue to evaluate and execute on such opportunities. As we have in the past, we will evaluate growth projects and acquisitions as such opportunities may be identified in the future, and we believe that the current capital markets are conducive to funding such future projects.

With respect to commodity prices, crude oil and NGL prices have rebounded sharply from the lows experienced in early 2016. Current commodity pricing has increased activities in several basins, as reflected by current rig counts. The addition of several ethane crackers and export projects currently under construction should help to volumetrically balance this market. Other factors such as reduced wet gas extraction will also help to balance this market and positively impact prices. Bakken crude oil output is continuing to increase, supporting strong spreads between North Dakota and the Gulf Coast.

Natural gas pricing is expected to remain within a range similar to recent history as increased supply continues to outpace demand. Texas intrastate natural gas spreads are strong mostly due to increased production in the Permian Basin; Permian production is expected to continue growing considerably over the next several years, and most new takeaway capacity projects are not scheduled to go into service until beyond 2018. New demand occurring in several areas such as exports to Mexico and Canada, LNG exports, nuclear power plant de-commissioning, as well as continued coal to gas switching for power generation, will help pricing; however, supply is continuing to increase.

Results of Operations

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, depletion, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for unconsolidated affiliates based on the Partnership's proportionate ownership.

Adjusted EBITDA is a non-GAAP measure. Although we include Segment Adjusted EBITDA in this report, we have not included an analysis of the consolidated measure, Adjusted EBITDA. We have included a total of Segment Adjusted EBITDA for all segments, which is reconciled to the GAAP measure of net income in the consolidated results sections that follow.

As discussed in Note 1 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data," the merger of legacy ETP and legacy Sunoco Logistics in April 2017 resulted in legacy ETP being treated as the surviving entity from an accounting perspective. Accordingly, the financial data below reflects the consolidated financial information of legacy ETP.

As discussed in Note 2 to the Partnership's consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data," in the fourth quarter of 2017, the Partnership changed its accounting policy related to certain inventories. Certain crude oil, refined product and NGL inventories were changed from last-in, first-out ("LIFO") method to the weighted average cost method. These changes have been applied retrospectively to all periods presented, and the prior period amounts reflected below have been adjusted from those amounts previously reported.

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

Consolidated Results

	Years Ended December 31,		
	2017	2016*	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 626	$ 613	$ 13
Interstate transportation and storage	1,098	1,117	(19)
Midstream	1,481	1,133	348
NGL and refined products transportation and services	1,641	1,496	145
Crude oil transportation and services	1,379	834	545
All other	487	540	(53)
Total	6,712	5,733	979
Depreciation, depletion and amortization	(2,332)	(1,986)	(346)
Interest expense, net	(1,365)	(1,317)	(48)
Gains on acquisitions	—	83	(83)
Impairment losses	(920)	(813)	(107)
Losses on interest rate derivatives	(37)	(12)	(25)
Non-cash unit-based compensation expense	(74)	(80)	6
Unrealized gain (loss) on commodity risk management activities	56	(131)	187
Losses on extinguishments of debt	(42)	—	(42)
Adjusted EBITDA related to unconsolidated affiliates	(984)	(946)	(38)
Equity in earnings of unconsolidated affiliates	156	59	97
Impairment of investments in unconsolidated affiliates	(313)	(308)	(5)
Other, net	148	115	33
Income before income tax benefit	1,005	397	608
Income tax benefit	1,496	186	1,310
Net income	$ 2,501	$ 583	$ 1,918

* As adjusted.

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased primarily due to additional depreciation from assets recently placed in service and recent acquisitions.

Impairment Losses. During the year ended December 31, 2017, the Partnership recorded impairments to goodwill associated with the compression business of $223 million, the entity that owns the general partner of Panhandle of $229 million, interstate transportation and storage operations of $262 million, and refined products transportation and services operations of $79 million. Also, during the year ended December 31, 2017, the Partnership recorded an impairment to the property, plant and equipment of Sea Robin of $127 million. During the year ended December 31, 2016, the Partnership recorded impairments to goodwill associated with the interstate transportation and storage operations $638 million and the midstream operations $32 million. Also, during the year ended December 31, 2016, the Partnership recorded impairments to the property, plant and equipment in the interstate transportation and storage segment $133 million and in the midstream segment $10 million. Additional discussion on these impairments is included in "Estimates and Critical Accounting Policies" below.

Losses on Interest Rate Derivatives. Our interest rate derivatives are not designated as hedges for accounting purposes; therefore, changes in fair value are recorded in earnings each period. Losses on interest rate derivatives during the years ended December 31, 2017 and 2016 resulted from decreases in forward interest rates, which caused our forward-starting swaps to change in value.

Unrealized Gain (Loss) on Commodity Risk Management Activities. See additional information on unrealized gain (loss) on commodity risk management activities included in "Segment Operating Results" below.

Adjusted EBITDA Related to Unconsolidated Affiliates and *Equity in Earnings of Unconsolidated Affiliates.* See additional information in "Supplemental Information on Unconsolidated Affiliates" and "Segment Operation Results" below.

Impairment of Investments in Unconsolidated Affiliates. During the year ended December 31, 2017, the Partnership recorded impairments to its investments in FEP of $141 million and HPC of $172 million. During the year ended December 31, 2016, the Partnership recorded an impairment to its investment in MEP of $308 million. Additional discussion on these impairments is included in "Estimates and Critical Accounting Policies" below.

Other, net. Other, net primarily includes amortization of regulatory assets and other income and expense amounts.

Income Tax Benefit. On December 22, 2017, the Tax Cuts and Jobs Act was signed into law. Among other provisions, the highest corporate federal income tax rate was reduced from 35% to 21% for taxable years beginning after December 31, 2017. As a result, the Partnership recognized a deferred tax benefit of $1.56 billion in December 2017. For the year ended December 2016, the Partnership recorded an income tax benefit due to pre-tax losses at its corporate subsidiaries.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31,		
	2017	2016	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 144	$ 102	$ 42
FEP	53	51	2
MEP	38	40	(2)
HPC[1]	(168)	31	(199)
Sunoco LP[2]	12	(211)	223
Other	77	46	31
Total equity in earnings of unconsolidated affiliates	$ 156	$ 59	$ 97
Adjusted EBITDA related to unconsolidated affiliates[3]:			
Citrus	$ 336	$ 329	$ 7
FEP	74	75	(1)
MEP	88	90	(2)
HPC	46	61	(15)
Sunoco LP	268	271	(3)
Other	172	120	52
Total Adjusted EBITDA related to unconsolidated affiliates	$ 984	$ 946	$ 38
Distributions received from unconsolidated affiliates:			
Citrus	$ 156	$ 144	$ 12
FEP	47	65	(18)
MEP	114	74	40
HPC	35	51	(16)
Sunoco LP	144	138	6
Other	80	69	11
Total distributions received from unconsolidated affiliates	$ 576	$ 541	$ 35

(1) For the year ended December 31, 2017, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by HPC, which reduced the Partnership's equity in earnings by $185 million.

(2) For the years ended December 31, 2017 and 2016, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by Sunoco LP, which reduced the Partnership's equity in earnings by $176 million and $277 million, respectively.

(3) These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates and are based on our equity in earnings or losses of our unconsolidated affiliates adjusted for our proportionate share of the unconsolidated affiliates' interest, depreciation, depletion, amortization, non-cash items and taxes.

Segment Operating Results

We evaluate segment performance based on Segment Adjusted EBITDA, which we believe is an important performance measure of the core profitability of our operations. This measure represents the basis of our internal financial reporting and is one of the performance measures used by senior management in deciding how to allocate capital resources among business segments.

The tables below identify the components of Segment Adjusted EBITDA, which is calculated as follows:

- *Segment margin, operating expenses,* and *selling, general and administrative expenses*. These amounts represent the amounts included in our consolidated financial statements that are attributable to each segment.

- *Unrealized gains or losses on commodity risk management activities* and *inventory valuation adjustments*. These are the unrealized amounts that are included in cost of products sold to calculate segment margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.
- *Non-cash compensation expense*. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative expenses. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.
- *Adjusted EBITDA related to unconsolidated affiliates*. These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates. Amounts reflected are calculated consistently with our definition of Adjusted EBITDA.

In the following analysis of segment operating results, a measure of segment margin is reported for segments with sales revenues. Segment Margin is a non-GAAP financial measure and is presented herein to assist in the analysis of segment operating results and particularly to facilitate an understanding of the impacts that changes in sales revenues have on the segment performance measure of Segment Adjusted EBITDA. Segment Margin is similar to the GAAP measure of gross margin, except that Segment Margin excludes charges for depreciation, depletion and amortization.

In addition, for certain segments, the sections below include information on the components of Segment Margin by sales type, which components are included in order to provide additional disaggregated information to facilitate the analysis of Segment Margin and Segment Adjusted EBITDA. For example, these components include transportation margin, storage margin, and other margin. These components of Segment Margin are calculated consistent with the calculation of Segment Margin; therefore, these components also exclude charges for depreciation, depletion and amortization.

For additional information regarding our business segments, see “Item 1. Business” and Notes 1 and 15 to our consolidated financial statements in “Item 8. Financial Statements and Supplementary Data.”

Following is a reconciliation of Segment Margin to operating income, as reported in the Partnership’s consolidated statements of operations:

	Years Ended December 31,	
	2017	2016
Intrastate transportation and storage	$ 756	$ 716
Interstate transportation and storage	934	969
Midstream	2,182	1,798
NGL and refined products transportation and services	2,140	1,856
Crude oil transportation and services	1,877	1,123
All other	392	330
Intersegment eliminations	(28)	(45)
Total segment margin	8,253	6,747
Less:		
Operating expenses	2,170	1,839
Depreciation, depletion and amortization	2,332	1,986
Selling, general and administrative	434	348
Impairment losses	920	813
Operating income	$ 2,397	$ 1,761

Intrastate Transportation and Storage

	Years Ended December 31,		
	2017	2016	Change
Natural gas transported (BBtu/d)	8,760	8,328	432
Revenues	$ 3,083	$ 2,613	$ 470
Cost of products sold	2,327	1,897	430
Segment margin	756	716	40
Unrealized (gains) losses on commodity risk management activities	(5)	19	(24)
Operating expenses, excluding non-cash compensation expense	(168)	(162)	(6)
Selling, general and administrative expenses, excluding non-cash compensation expense	(22)	(22)	—
Adjusted EBITDA related to unconsolidated affiliates	64	61	3
Other	1	1	—
Segment Adjusted EBITDA	$ 626	$ 613	$ 13

Volumes. For the year ended December 31, 2017 compared to the prior year, transported volumes increased primarily due to higher demand for exports to Mexico, more favorable market pricing, and the addition of new pipelines to our intrastate pipeline system. These increases were partially offset by lower production volumes in the Barnett Shale region.

Segment Margin. The components of our intrastate transportation and storage segment margin were as follows:

	Years Ended December 31,		
	2017	2016	Change
Transportation fees	$ 448	$ 505	$ (57)
Natural gas sales and other	193	113	80
Retained fuel revenues	62	48	14
Storage margin, including fees	53	50	3
Total segment margin	$ 756	$ 716	$ 40

Segment Adjusted EBITDA. For the year ended December 31, 2017 compared to the prior year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $74 million in natural gas sales and other (excluding net changes in unrealized gains and losses of $6 million) primarily due to higher realized gains from pipeline optimization activity;
- an increase of $10 million in retained fuel sales (excluding net changes in unrealized gains and losses of $4 million) primarily due to higher market prices. The average spot price at the Houston Ship Channel location increased 22% for the year ended December 31, 2017 compared to the prior year; and
- an increase of $3 million in adjusted EBITDA related to unconsolidated affiliates primarily due to an increase of $16 million related to two new joint venture pipelines placed in service in 2017, offset by a decrease of $6 million due to lower demand volumes related to renegotiation of a contract on our Louisiana intrastate pipeline system in 2017 and a decrease of $7 million due to a reserve recorded in 2017 pursuant to the bankruptcy filing of a transport customer on our Louisiana intrastate system; offset by
- a decrease in transportation fees of $57 million due to renegotiated contracts resulting in lower billed volumes. This decrease was offset by increased margin from optimization activity recorded in natural gas sales and other;
- a decrease of $11 million in storage margin (excluding net changes in unrealized gains and losses of $14 million related to fair value inventory adjustments and unrealized gains and losses on derivatives), as discussed below; and
- an increase of $6 million in operating expenses primarily due to higher compression fuel expense relating to increased market price and run times at various compressor stations.

Storage margin was comprised of the following:

	Years Ended December 31,		
	2017	2016	Change
Withdrawals from storage natural gas inventory (BBtu)	27,195	38,905	(11,710)
Realized margin on natural gas inventory transactions	$ 24	$ 36	$ (12)
Fair value inventory adjustments	(35)	76	(111)
Unrealized gains (losses) on derivatives	38	(87)	125
Margin recognized on natural gas inventory, including related derivatives	27	25	2
Revenues from fee-based storage	26	25	1
Total storage margin	$ 53	$ 50	$ 3

The changes in storage margin were primarily due to the movement in market price of the physical storage gas and the financial derivatives used to hedge that gas.

Interstate Transportation and Storage

	Years Ended December 31,		
	2017	2016	Change
Natural gas transported (BBtu/d)	6,082	5,476	606
Natural gas sold (BBtu/d)	18	19	(1)
Revenues	$ 934	$ 969	$ (35)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(296)	(302)	6
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(46)	(47)	1
Adjusted EBITDA related to unconsolidated affiliates	498	494	4
Other	8	3	5
Segment Adjusted EBITDA	$ 1,098	$ 1,117	$ (19)

Volumes. For the year ended December 31, 2017 compared to the prior year, transported volumes increased 283 BBtu/d due to the partial in service of the Rover pipeline, 148 BBtu/d on the Tiger pipeline due to an increase in production in the Haynesville Shale and deliveries into third party storage and the intrastate markets, and 128 BBtu/d and 78 BBtu/d on the Trunkline and Panhandle pipelines, respectively, due to higher demand resulting from colder weather.

Segment Adjusted EBITDA. For the year ended December 31, 2017 compared to the prior year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impacts of the following:

- a net decrease of $35 million in revenues primarily due to a decrease in reservation revenues of $45 million on the Panhandle, Trunkline, and Transwestern pipelines, a decrease of $17 million in gas parking service related revenues on the Panhandle and Trunkline pipelines primarily due to lack of customer demand resulting from weak spreads, a decrease of $19 million in revenues on the Tiger pipeline due to contract restructuring, and a decrease of $5 million on the Sea Robin pipeline due to producer maintenance and production declines. These decreases were partially offset by $55 million of incremental revenues from the placement in partial service of the Rover pipeline effective August 31, 2017; offset by
- a decrease in operating expenses of $6 million primarily due to lower allocated costs of $8 million and lower lease storage expense of $4 million due to expiration of a lease. These decreases were partially offset by higher ad valorem taxes resulting from higher valuations;
- an increase in adjusted EBITDA from unconsolidated affiliates of $4 million due to an increase of $6 million related to a legal settlement, an increase of $3 million resulting from higher sales of short term firm capacity on Citrus and $2 million related to higher tax gross up income from reimbursable projects on Citrus. These increases were partially offset by lower reservation revenues on MEP primarily due to a contract modification and expiring contracts; and
- an increase in other of $5 million primarily due to higher tax gross up income from reimbursable projects.

Midstream

	Years Ended December 31,		
	2017	2016	Change
Gathered volumes (BBtu/d)	10,956	9,814	1,142
NGLs produced (MBbls/d)	457	438	19
Equity NGLs (MBbls/d)	27	31	(4)
Revenues	$ 6,943	$ 5,179	$ 1,764
Cost of products sold	4,761	3,381	1,380
Segment margin	2,182	1,798	384
Unrealized (gains) losses on commodity risk management activities	(15)	15	(30)
Operating expenses, excluding non-cash compensation expense	(638)	(621)	(17)
Selling, general and administrative expenses, excluding non-cash compensation expense	(78)	(84)	6
Adjusted EBITDA related to unconsolidated affiliates	28	24	4
Other	2	1	1
Segment Adjusted EBITDA	$ 1,481	$ 1,133	$ 348

Volumes. Gathered volumes and NGL production increased during the year ended December 31, 2017 compared to the prior year primarily due to recent acquisitions, including PennTex, and gains in the Permian, Northeast and South Texas regions, partially offset by basin declines in North Texas and Mid-Continent/Panhandle regions.

Segment Margin. The components of our midstream segment margin were as follows:

	Years Ended December 31,		
	2017	2016	Change
Gathering and processing fee-based revenues	$ 1,695	$ 1,551	$ 144
Non-fee based contracts and processing	487	247	240
Total segment margin	$ 2,182	$ 1,798	$ 384

Segment Adjusted EBITDA. For the year ended December 31, 2017 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impacts of the following:

- an increase of $150 million in non-fee based margins due to higher crude oil and NGL prices;
- an increase of $60 million in non-fee based margin (excluding net changes in unrealized gains and losses of $30 million) due to volume increases in the Permian, Northeast and South Texas regions, partially offset by volume declines in the North Texas and the Mid-Continent/Panhandle regions;
- an increase of $80 million in fee-based revenue due to minimum volume commitments in the South Texas region, as well as volume increases in the Permian and Northeast regions. These increases were partially offset by volume declines in the North Texas and the Mid-Continent/Panhandle regions;
- an increase of $64 million in fee-based revenue due to recent acquisitions, including PennTex; and
- a decrease in selling, general and administrative expenses of $6 million primarily due to a favorable impact from the adjustment of certain reserves that had previously been recorded in connection with contingent matters. This decrease was partially offset by a decrease in capitalized overhead of $11 million and an increase in shared services allocation of $14 million; partially offset by
- an increase in operating expenses of $17 million primarily due to recent acquisitions, including PennTex.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2017	2016	Change
NGL transportation volumes (MBbls/d)	863	754	109
Refined products transportation volumes (MBbls/d)	624	599	25
NGL and refined products terminal volumes (MBbls/d)	793	791	2
NGL fractionation volumes (MBbls/d)	427	361	66
Revenues	$ 8,648	$ 6,409	$ 2,239
Cost of products sold	6,508	4,553	1,955
Segment margin	2,140	1,856	284
Unrealized (gains) losses on commodity risk management activities	(26)	69	(95)
Operating expenses, excluding non-cash compensation expense	(478)	(441)	(37)
Selling, general and administrative expenses, excluding non-cash compensation expense	(64)	(56)	(8)
Adjusted EBITDA related to unconsolidated affiliates	68	67	1
Other	1	1	—
Segment Adjusted EBITDA	$ 1,641	$ 1,496	$ 145

Volumes. For the year ended December 31, 2017 compared to the prior year, NGL and refined product transportation volumes increased from the Permian, Barnett/East Texas, Eagle Ford, Southeast Texas, Marcellus and Louisiana. NGL and refined products terminal volumes increased slightly for the year ended December 31, 2017 primarily due to increased throughput at our Marcus Hook Industrial Complex from the Northeast producing region, the impact of which was partially offset by the sale of one of our refined product terminals in April 2017.

Average volumes fractionated at our Mont Belvieu, Texas fractionation facility increased 22% for the year ended December 31, 2017 compared to the prior year primarily due to the commissioning of our fourth fractionator in October of 2016, which has a capacity of 120 MBbls/d, as well as increased producer volumes as mentioned above.

Segment Margin. The components of our NGL and refined products transportation and services segment margin were as follows:

	Years Ended December 31,		
	2017	2016	Change
Fractionators and Refinery services margin	$ 488	$ 404	$ 84
Transportation margin	990	866	124
Storage margin	214	208	6
Terminal Services margin	351	322	29
Marketing margin	97	56	41
Total segment margin	$ 2,140	$ 1,856	$ 284

Segment Adjusted EBITDA. For the year ended December 31, 2017 compared to the prior year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase in transportation margin of $124 million primarily due to increased throughput on our Texas NGL pipelines resulting from increased producer services as noted above and the ramp up of volumes on our Mariner East system;
- an increase in fractionation and refinery services margin of $81 million (excluding changes in unrealized gains and losses of $3 million) primarily due to higher NGL volumes from most major producing regions feeding our Mont Belvieu fractionation facility, the first full year of service for our fourth fractionator at Mont Belvieu, Texas, and a $17 million increase from blending gains as a result of improved market pricing, as noted above;
- an increase in terminal services margin of $29 million due to a $43 million increase resulting from higher throughput volumes at our Marcus Hook and Nederland NGL terminals. This increase was partially offset by a $14 million decrease resulting from lower refined products terminal throughput and the sale of one of our refined product terminals in April of 2017; and

- an increase in storage margin of $6 million primarily due to a $4 million increase from Hattiesburg storage caverns as a result of a new storage contract effective in April 2017 as well as a $2 million increase from propane and butane blending gains as a result of improved market pricing; offset by
- a decrease in marketing margin of $54 million (excluding changes in unrealized gains of $95 million) primarily due to the timing of the recognition of margin from optimization activities;
- an increase in operating expenses of $37 million due to a $16 million increase related to the fourth fractionator being placed into service in October 2016, a $11 million increase related to higher utility expenses on our Texas NGL pipes, a $5 million increase due to higher right-of-way expenses primarily on our legacy Sunoco Logistics assets, and a $4 million increase from our Mont Belvieu storage assets primarily due to higher employee costs; and
- an increase in general and administrative expenses of $8 million due to higher allocations.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2017	2016	Change
Crude Transportation Volumes (MBbls/d)	3,491	2,652	839
Crude Terminals Volumes (MBbls/d)	1,928	1,537	391
Revenue	$ 11,703	$ 7,539	$ 4,164
Cost of products sold	9,826	6,416	3,410
Segment margin	1,877	1,123	754
Unrealized losses on commodity risk management activities	1	2	(1)
Operating expenses, excluding non-cash compensation expense	(430)	(247)	(183)
Selling, general and administrative expenses, excluding non-cash compensation expense	(82)	(58)	(24)
Adjusted EBITDA related to unconsolidated affiliates	13	14	(1)
Segment Adjusted EBITDA	$ 1,379	$ 834	$ 545

Segment Adjusted EBITDA. For the year ended December 31, 2017 compared to the prior year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the net impacts of the following:

- an increase of $724 million resulting primarily from placing our Bakken Pipeline in service in the second quarter of 2017, as well as the acquisition of a crude oil gathering system in West Texas, and the addition of a joint venture crude transportation assets;
- an increase of $90 million from existing transport assets due to increased volumes throughout the system; and
- an increase of $16 million from increased throughput fees and tank rentals, primarily from increased activity at our Nederland, Texas crude terminal; offset by
- a decrease of $78 million in margin from our crude oil acquisition and marketing business resulting from less favorable market price spreads particularly in the first three quarters of 2017;
- an increase of $183 million in operating expenses primarily due to an increase of $130 million resulting primarily from placing the Bakken Pipeline as well as certain joint venture crude transportation assets in service in the first and second quarters of 2017, an increase of $46 million due to higher utilities, line testing, and environmental costs from existing transport assets, an increase of $6 million for losses related to Hurricane Harvey; and
- an increase of $24 million in selling, general and administrative expenses primarily due to merger fees and legal and environmental reserves.

All Other

	Years Ended December 31,		
	2017	2016	Change
Revenue	$ 2,901	$ 3,272	$ (371)
Cost of products sold	2,509	2,942	(433)
Segment margin	392	330	62
Unrealized (gains) losses on commodity risk management activities	(11)	26	(37)
Operating expenses, excluding non-cash compensation expense	(117)	(79)	(38)
Selling, general and administrative expenses, excluding non-cash compensation expense	(103)	(86)	(17)
Adjusted EBITDA related to unconsolidated affiliates	313	286	27
Other	14	95	(81)
Elimination	(1)	(32)	31
Segment Adjusted EBITDA	$ 487	$ 540	$ (53)

Amounts reflected in our all other segment primarily include:

- our equity method investment in limited partnership units of Sunoco LP. As of December 31, 2017, our investment consisted of 43.5 million units, representing 43.6% of Sunoco LP's total outstanding common units. Subsequent to Sunoco LP's repurchase of a portion of its common units on February 7, 2018, our investment consists of 26.2 million units, representing 31.8% of Sunoco LP's total outstanding common units;
- our natural gas marketing and compression operations;
- a non-controlling interest in PES, comprising 33% of PES' outstanding common units; and
- our investment in coal handling facilities.

Segment Adjusted EBITDA. For the year ended December 31, 2017 compared to the prior year, Segment Adjusted EBITDA decreased due to the net impact of the following:

- a decrease of $90 million related to the termination of management fees paid by ETE that ended in 2016;
- an increase of $17 million in selling, general and administrative expenses primarily from higher transaction-related expenses; and
- a decrease of $31 million from the mark-to-market of physical system gas and settled derivatives; partially offset by
- an increase of $33 million in Adjusted EBITDA related to our investment in PES;
- a one-time fee of $15 million received from a joint venture affiliate;
- an increase of $20 million in crude and power trading activates, primarily from the liquidation of crude inventories; and
- a decrease of $11 million in expenses related to our compression business.

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

Consolidated Results

	Years Ended December 31,		
	2016*	2015*	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 613	$ 543	$ 70
Interstate transportation and storage	1,117	1,155	(38)
Midstream	1,133	1,237	(104)
NGL and refined products transportation and services	1,496	1,179	317
Crude oil transportation and services	834	521	313
All other	540	882	(342)
Total	5,733	5,517	216
Depreciation, depletion and amortization	(1,986)	(1,929)	(57)
Interest expense, net	(1,317)	(1,291)	(26)
Gains on acquisitions	83	—	83
Impairment losses	(813)	(339)	(474)
Losses on interest rate derivatives	(12)	(18)	6
Non-cash compensation expense	(80)	(79)	(1)
Unrealized losses on commodity risk management activities	(131)	(65)	(66)
Inventory valuation adjustments	—	58	(58)
Losses on extinguishments of debt	—	(43)	43
Adjusted EBITDA related to unconsolidated affiliates	(946)	(937)	(9)
Equity in earnings of unconsolidated affiliates	59	469	(410)
Impairment of investment in an unconsolidated affiliate	(308)	—	(308)
Other, net	115	23	92
Income before income tax benefit	397	1,366	(969)
Income tax benefit	186	123	63
Net income	$ 583	$ 1,489	$ (906)

* As adjusted.

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased primarily due to increases from assets recently placed in service, partially offset by a decrease of $191 million related to the deconsolidation of Sunoco, LLC and the legacy Sunoco, Inc. retail business.

Gains on Acquisitions. Gains on acquisitions include gains of $83 million in connection with recent acquisitions during 2016, including $41 million related to legacy Sunoco Logistics' acquisition of the remaining interest in SunVit.

Impairment Losses. In 2016, we recorded goodwill impairments of $638 million in the interstate transportation and storage segment and $32 million in the midstream segment. These goodwill impairments were primarily due to decreases in projected future revenues and cash flows driven by declines in commodity prices and changes in the markets that these assets serve. In addition, impairment losses for 2016 also include a $133 million impairment to property, plant and equipment in the interstate transportation and storage segment due to a decrease in projected future cash flows as well as a $10 million impairment to property, plant and equipment in the midstream segment. In 2015, we recorded goodwill impairments of (i) $99 million related to Transwestern due primarily to the market declines in current and expected future commodity prices in the fourth quarter of 2015, (ii) $106 million related to Lone Star Refinery Services due primarily to changes in assumptions related to potential future revenues as well as the market declines in current and expected future commodity prices, (iii) $110 million of fixed asset impairments related to Lone Star NGL Refinery Services primarily due to the economic obsolescence identified as a result of low utilization and expected

decrease in future cash flows, and (iv) $24 million of intangible asset impairments related to Lone Star NGL Refinery Services primarily due to the economic obsolescence identified as a result of expected decrease in future cash flows.

Losses on Interest Rate Derivatives. Our interest rate derivatives are not designated as hedges for accounting purposes; therefore, changes in fair value are recorded in earnings each period. Losses on interest rate derivatives during the years ended December 31, 2016 and 2015 resulted from decreases in forward interest rates, which caused our forward-starting swaps to decrease in value.

Unrealized Losses on Commodity Risk Management Activities. See discussion of the unrealized gains (losses) on commodity risk management activities included in "Segment Operating Results" below.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with our retail marketing operations as a result of commodity price changes between periods.

Adjusted EBITDA Related to Unconsolidated Affiliates and *Equity in Earnings of Unconsolidated Affiliates.* See additional information in "Supplemental Information on Unconsolidated Affiliates" and "Segment Operation Results" below.

Impairment of Investment in an Unconsolidated Affiliate. In 2016, the Partnership impaired its investment in MEP and recorded a non-cash impairment loss of $308 million based on commercial discussions with current and potential shippers on MEP regarding the outlook for long-term transportation contract rates.

Other, net. Other, net in 2016 and 2015 primarily includes amortization of regulatory assets and other income and expense amounts.

Income Tax Benefit. For the years ended December 31, 2016 and 2015, the Partnership recorded an income tax benefit due to pre-tax losses at its corporate subsidiaries. The year ended December 31, 2015 also reflected a benefit of $24 million of net state tax benefit attributable to statutory state rate changes resulting from the Regency Merger and sale of Susser to Sunoco LP, as well as a favorable impact of $11 million due to a reduction in the statutory Texas franchise tax rate which was enacted by the Texas legislature during the second quarter of 2015.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31,		
	2016	2015	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 102	$ 97	$ 5
FEP	51	55	(4)
MEP	40	45	(5)
HPC	31	32	(1)
Sunoco, LLC	—	(10)	10
Sunoco LP [1]	(211)	202	(413)
Other	46	48	(2)
Total equity in earnings of unconsolidated affiliates	$ 59	$ 469	$ (410)
Adjusted EBITDA related to unconsolidated affiliates [2]:			
Citrus	$ 329	$ 315	$ 14
FEP	75	75	—
MEP	90	96	(6)
HPC	61	61	—
Sunoco, LLC	—	91	(91)
Sunoco LP	271	137	134
Other	120	162	(42)
Total Adjusted EBITDA related to unconsolidated affiliates	$ 946	$ 937	$ 9
Distributions received from unconsolidated affiliates:			
Citrus	$ 144	$ 182	$ (38)
FEP	65	69	(4)
MEP	74	80	(6)
HPC	51	52	(1)
Sunoco LP	138	39	99
Other	69	142	(73)
Total distributions received from unconsolidated affiliates	$ 541	$ 564	$ (23)

(1) For the year ended December 31, 2016, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by Sunoco LP, which reduced the Partnership's equity in earnings by $277 million.

(2) These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates and are based on our equity in earnings or losses of our unconsolidated affiliates adjusted for our proportionate share of the unconsolidated affiliates' interest, depreciation, depletion, amortization, non-cash items and taxes.

Segment Operating Results

Following is a reconciliation of Segment Margin to operating income, as reported in the Partnership's consolidated statements of operations:

	Years Ended December 31,	
	2016	2015
Intrastate transportation and storage	$ 716	$ 696
Interstate transportation and storage	969	1,025
Midstream	1,798	1,792
NGL and refined products transportation and services	1,856	1,566
Crude oil transportation and services	1,123	822
All other	330	1,745
Intersegment eliminations	(45)	(68)
Total segment margin	6,747	7,578
Less:		
Operating expenses	1,839	2,608
Depreciation, depletion and amortization	1,986	1,929
Selling, general and administrative	348	475
Impairment losses	813	339
Operating income	$ 1,761	$ 2,227

Intrastate Transportation and Storage

	Years Ended December 31,		
	2016	2015	Change
Natural gas transported (BBtu/d)	8,328	8,427	(99)
Revenues	$ 2,613	$ 2,250	$ 363
Cost of products sold	1,897	1,554	343
Segment margin	716	696	20
Unrealized (gains) losses on commodity risk management activities	19	(26)	45
Operating expenses, excluding non-cash compensation expense	(162)	(163)	1
Selling, general and administrative, excluding non-cash compensation expense	(22)	(25)	3
Adjusted EBITDA related to unconsolidated affiliates	61	61	—
Other	1	—	1
Segment Adjusted EBITDA	$ 613	$ 543	$ 70

Volumes. For the year ended December 31, 2016 compared to the prior year, transported volumes decreased primarily due to lower production volumes in the Barnett Shale region, partially offset by increased volumes related to significant new long-term transportation contracts, as well as the addition of a new short-haul transport pipeline delivering volumes into our Houston Pipeline system.

Gross Margin. The components of our intrastate transportation and storage segment gross margin were as follows:

	Years Ended December 31,		
	2016	2015	Change
Transportation fees	$ 505	$ 502	$ 3
Natural gas sales and other	113	96	17
Retained fuel revenues	48	57	(9)
Storage margin, including fees	50	41	9
Total segment margin	$ 716	$ 696	$ 20

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $3 million in transportation fees, despite lower throughput volumes, due to fees from renegotiated and newly initiated fixed fee contracts primarily on our Houston Pipeline system;
- an increase of $34 million in natural gas sales (excluding changes in unrealized losses of $17 million) primarily due to higher realized gains from the buying and selling of gas along our system;
- a decrease of $9 million from the sale of retained fuel, primarily due to lower market prices and lower volumes. The average spot price at the Houston Ship Channel location decreased 5% for the year ended December 31, 2016 compared to the prior year;
- an increase of $37 million in storage margin (excluding net changes in unrealized amounts of $28 million related to fair value inventory adjustments and unrealized gains and losses on derivatives), as discussed below; and
- a decrease of $3 million in general and administrative expenses primarily due to lower legal fees and insurance costs, as well as allocations between segments.

Storage margin was comprised of the following:

	Years Ended December 31,		
	2016	2015	Change
Withdrawals from storage natural gas inventory (BBtu)	38,905	15,783	23,122
Realized margin on natural gas inventory transactions	$ 36	$ (2)	$ 38
Fair value inventory adjustments	76	4	72
Unrealized gains (losses) on derivatives	(87)	12	(99)
Margin recognized on natural gas inventory, including related derivatives	25	14	11
Revenues from fee-based storage	25	27	(2)
Total storage margin	$ 50	$ 41	$ 9

The changes in storage margin were primarily driven by the timing of withdrawals and sales of natural gas from our Bammel storage cavern, as well as the timing of settlement of related derivative hedging contracts.

Interstate Transportation and Storage

	Years Ended December 31,		
	2016	2015	Change
Natural gas transported (BBtu/d)	5,476	6,074	(598)
Natural gas sold (BBtu/d)	19	17	2
Revenues	$ 969	$ 1,025	$ (56)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(302)	(304)	2
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(47)	(52)	5
Adjusted EBITDA related to unconsolidated affiliates	494	486	8
Other	3	—	3
Segment Adjusted EBITDA	$ 1,117	$ 1,155	$ (38)

Volumes. For the year ended December 31, 2016 compared to the prior year, transported volumes decreased 424 BBtu/d on the Trunkline pipeline due to the transfer of one of the pipelines at Trunkline which was repurposed from natural gas service to crude oil service and lower utilization resulting from lower customer demand. Transported volumes decreased 82 BBtu/d on the Transwestern pipe line due to milder weather in the West and decreased 76 BBtu/d on the Sea Robin pipeline due to reduced supply as a result of producer system maintenance and overall lower production.

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $26 million in revenues due to contract restructuring on the Tiger pipeline, a decrease of $17 million due to lower reservation revenues on the Panhandle and Trunkline pipelines from capacity sold at lower rates and lower sales of capacity in the Phoenix and San Juan areas on the Transwestern pipeline, a decrease of $14 million due to the transfer of one of the Trunkline pipelines which was repurposed from natural gas service to crude oil service, a decrease of $11 million due to the expiration of a transportation rate schedule on the Transwestern pipeline, and a decrease of $10 million on the Sea Robin pipeline due to declines in production and third-party maintenance. These decreases were partially offset by higher reservation revenues on the Transwestern pipeline of $18 million, primarily from a growth project, and higher parking revenues of $9 million, primarily on the Panhandle and Trunkline pipelines; partially offset by
- an increase of $8 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to higher margins from sales of additional capacity on Citrus of $6 million and lower operating expenses of $5 million, offset by lower margins on MEP of $4 million due to a customer bankruptcy;
- a decrease of $2 million in operating expenses primarily due to lower maintenance project costs of $5 million and lower allocated costs of $3 million. These decreases were partially offset by an increase of $7 million in ad valorem tax expense due to higher current year assessments of $2 million and a prior period credit and settlement of ad valorem taxes in 2015 of $5 million;
- a decrease of $5 million in selling, general and administrative expenses primarily due to $5 million in lower allocated costs; and
- an increase of $3 million in other primarily due to the tax gross-up associated with reimbursable projects on the Transwestern and Panhandle pipelines.

Midstream

	Years Ended December 31,		
	2016	2015	Change
Gathered volumes (BBtu/d):	9,814	9,981	(167)
NGLs produced (MBbls/d):	438	406	32
Equity NGLs (MBbls/d):	31	28	3
Revenues	$ 5,179	$ 5,056	$ 123
Cost of products sold	3,381	3,264	117
Segment margin	1,798	1,792	6
Unrealized losses on commodity risk management activities	15	82	(67)
Operating expenses, excluding non-cash compensation expense	(621)	(616)	(5)
Selling, general and administrative, excluding non-cash compensation expense	(84)	(44)	(40)
Adjusted EBITDA related to unconsolidated affiliates	24	20	4
Other	1	3	(2)
Segment Adjusted EBITDA	$ 1,133	$ 1,237	$ (104)

Volumes. Gathered volumes decreased during the year ended December 31, 2016 compared to the prior year primarily due to declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions, partially offset by increases in the Permian region and the impact of recent acquisitions, including PennTex. NGL production increased due to increased gathering and processing capacities in the Permian region, partially offset by declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions.

Segment Margin. The components of our midstream segment margin were as follows:

	Years Ended December 31,		
	2016	2015	Change
Gathering and processing fee-based revenues	$ 1,551	$ 1,570	$ (19)
Non-fee based contracts and processing	247	222	25
Total segment margin	$ 1,798	$ 1,792	$ 6

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net impacts of the following:

- a decrease of $16 million in fee-based margin due to volume declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions, partially offset by increased gathering and processing volumes in the Permian region and the impact of recent acquisitions, including PennTex and the King Ranch assets;
- an increase of $40 million in general and administrative expenses primarily due to costs associated with the acquisition of PennTex and changes in capitalized overhead and accruals;
- an increase of $5 million in operating expenses primarily due to the King Ranch acquisition in the second quarter of 2015 and assets recently placed in service in the Permian and Eagle Ford regions; and
- a decrease of $92 million (excluding unrealized gains of $67 million) in non-fee based margin due to lower benefit from settled derivatives used to hedge commodity margins; partially offset by
- an increase of $44 million in non-fee based margin due to volume increases in the Permian region, partially offset by volume declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions; and
- an increase of $3 million in non-fee based margin due to higher crude oil and NGL prices, partially offset by lower natural gas prices.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2016	2015	Change
NGL transportation volumes (MBbls/d)	754	617	137
Refined products transportation volumes (MBbls/d)	599	518	81
NGL and refined products terminal volumes (MBbls/d)	791	718	73
NGL fractionation volumes (MBbls/d)	361	236	125
Revenues	$ 6,409	$ 4,997	$ 1,412
Cost of products sold	4,553	3,431	1,122
Segment margin	1,856	1,566	290
Unrealized losses on commodity risk management activities	69	10	59
Operating expenses, excluding non-cash compensation expense	(441)	(408)	(33)
Selling, general and administrative expenses, excluding non-cash compensation expense	(56)	(56)	—
Adjusted EBITDA related to unconsolidated affiliates	67	67	—
Other	1	—	1
Segment Adjusted EBITDA	$ 1,496	$ 1,179	$ 317

Volumes. For the year ended December 31, 2016 compared to the prior year, NGL and refined products transportation volumes increased due to the ramp-up of our Mariner East 1, Mariner South and Allegheny Access growth projects as well as increased volumes from Permian, North Texas, and Southeast Texas. For the year ended December 31, 2016 compared to the prior year, NGL and refined products terminal volumes increased primarily due to the ramp-up of the previously mentioned growth projects.

Average daily fractionated volumes increased approximately 125 MBbls/d for the year ended December 31, 2016 compared to the prior year primarily due to the ramp-up of our third fractionator at Mont Belvieu, Texas, which was commissioned in late December 2015, as well as increased producer volumes mentioned above. Additionally, we placed our fourth fractionator in-service in November 2016, providing an additional 18 MBbls/d of throughput volume for the year.

Segment Margin. The components of our NGL and refined products transportation and services segment margin were as follows:

	Years Ended December 31,		
	2016	2015	Change
Fractionators and Refinery services margin	$ 404	$ 297	$ 107
Transportation margin	866	696	170
Storage margin	208	172	36
Terminal Services margin	322	253	69
Marketing margin	56	148	(92)
Total segment margin	$ 1,856	$ 1,566	$ 290

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase of $36 million in storage margin primarily due to increased volumes from our Mont Belvieu fractionators. Throughput volumes, on which we earn a fee in our storage assets, increased 34% resulting in an increase of $18 million compared to the prior year. We also realized an increase of $8 million due to increased demand for our leased storage capacity as a result of more favorable market conditions. Finally, we realized increased terminal fees and pipeline lease fees of $8 million, as well as increased blending gains of $2 million resulting from higher volumes during the 2016 period;
- an increase of $239 million in NGL and refined product transportation and terminal margin due to the ramp-up of several organic growth projects, including Mariner East 1, Mariner South and Allegheny Access as well as increased volumes from all producing regions, with the Permian region being the most significant among them;

- a $4 million increase in contributions from joint venture interests primarily driven by the acquisition of an additional 1.7% ownership interest in Explorer Pipeline Company; and
- an increase of $118 million in NGL processing and fractionation margin (excluding net changes in unrealized gains and losses of $11 million) primarily due to higher NGL volumes from all producing regions, as detailed in our transport fees explanation above. We placed approximately 118 MBbls/d of fractionation capacity in-service in 2016, allowing our Mont Belvieu fractionators to handle the significant increase in volumes from year to year. Additional barrels fractionated and an associated increase in blending gains at our fractionators resulted in a margin increase of $101 million. We delivered approximately 26% more barrels to our Mariner South LPG export terminal in the 2016 period, which resulted in an increase of $22 million in cargo loading fees and blending fees compared to the prior year. These gains were offset by an increase in storage fees paid of $2 million, and a decrease in margin from our refinery services operations of $3 million; partially offset by
- a decrease in marketing margin of $42 million (excluding net changes in unrealized gains and losses of $50 million) due to lower spreads compared to prior year as well as the timing of the withdrawal of NGL component product inventory and the recognition of margin from other optimization activities; and
- an increase of $33 million in operating expenses primarily due to increased costs associated with organic growth projects such as our third fractionator at Mont Belvieu, Mariner East 1, Mariner South and Allegheny Access.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2016	2015	Change
Crude Transportation Volumes (MBbls/d)	2,652	2,276	376
Crude Terminals Volumes (MBbls/d)	1,537	1,400	137
Revenue	$ 7,539	$ 8,980	$ (1,441)
Cost of products sold	6,416	8,158	(1,742)
Segment margin	1,123	822	301
Unrealized losses on commodity risk management activities	2	—	2
Operating expenses, excluding non-cash compensation expense	(247)	(246)	(1)
Selling, general and administrative expenses, excluding non-cash compensation expense	(58)	(53)	(5)
Adjusted EBITDA related to unconsolidated affiliates	14	(2)	16
Segment Adjusted EBITDA	$ 834	$ 521	$ 313

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the net impacts of the following:

- an increase of $158 million resulting primarily from placing our Permian Express II pipeline in service in the third quarter of 2015, as well as the acquisition of a crude oil gathering system in West Texas;
- an increase of $49 million from existing assets due to increased volumes throughout the system;
- an increase of $31 million from our crude terminals assets, largely related to the Nederland facility; and
- an increase of $74 million from our crude oil acquisition and marketing activity; offset by
- an increase of $5 million in selling, general and administrative expenses.

All Other

	Years Ended December 31,		
	2016	2015	Change
Revenue	$ 3,272	$ 15,774	$ (12,502)
Cost of products sold	2,942	14,029	(11,087)
Segment margin	330	1,745	(1,415)
Unrealized (gains) losses on commodity risk management activities	26	(1)	27
Operating expenses, excluding non-cash compensation expense	(79)	(896)	817
Selling, general and administrative expenses, excluding non-cash compensation expense	(86)	(254)	168
Adjusted EBITDA related to unconsolidated affiliates	286	313	(27)
Inventory valuation adjustments	—	(58)	58
Other	95	95	—
Elimination	(32)	(62)	30
Segment Adjusted EBITDA	$ 540	$ 882	$ (342)

Amounts reflected in our all other segment primarily include:

- our retail marketing operations prior to the transfer of the general partner interest of Sunoco LP from ETP to ETE in 2015 and completion of the dropdown of remaining Retail Marketing interests from ETP to Sunoco LP in March 2016;
- our equity method investment in limited partnership units of Sunoco LP consisting of 43.5 million units, representing 44.3% of Sunoco LP's total outstanding common units;
- our natural gas marketing and compression operations;
- a non-controlling interest in PES, comprising 33% of PES' outstanding common units; and
- our investment in coal handling facilities.

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA decreased due to the net impact of the following:

- a decrease of $308 million due to the transfer and contribution of our retail marketing assets to Sunoco LP. The consolidated results of Sunoco LP are reflected in the results for All Other above through June 2015. Effective July 1, 2015, Sunoco LP was deconsolidated, and the results for All Other reflect Adjusted EBITDA related to unconsolidated affiliates for our limited partner interests in Sunoco LP. The impact of the deconsolidation of Sunoco LP reduced segment margin, operating expenses and selling, general and administrative expenses; the impact to Segment Adjusted EBITDA is offset by the incremental Adjusted EBITDA related to unconsolidated affiliates from our equity method investment in Sunoco LP subsequent to the deconsolidation; and
- a decrease of $76 million in Adjusted EBITDA related to our investment in PES.

ETP provides management services for ETE for which ETE has agreed to pay management fees to ETP of $95 million per year for the years ending December 31, 2016 and 2015. These fees were reflected in "Other" in the "All other" segment and for the years ended December 31, 2016 and 2015 were reflected as an offset to operating expenses of $32 million and selling, general and administrative expenses of $63 million in the consolidated statements of operations.

Liquidity and Capital Resources

Our ability to satisfy our obligations and pay distributions to our Unitholders will depend on our future performance, which will be subject to prevailing economic, financial, business and weather conditions, and other factors, many of which are beyond management's control.

We currently expect capital expenditures in 2018 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$ 225	$ 250	$ 30	$ 35
Interstate transportation and storage [1]	450	500	115	120
Midstream	750	800	120	130
NGL and refined products transportation and services	2,425	2,475	65	75
Crude oil transportation and services [1]	425	525	90	100
All other (including eliminations)	75	100	60	65
Total capital expenditures	$ 4,350	$ 4,650	$ 480	$ 525

[1] Includes capital expenditures related to our proportionate ownership of the Bakken, Rover and Bayou Bridge pipeline projects.

The assets used in our natural gas and liquids operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, delays from steel mills, limited selection of mills capable of producing large diameter pipe timely, higher steel prices and other factors beyond our control. However, we include these factors in our anticipated growth capital expenditures for each year.

We generally fund maintenance capital expenditures and distributions with cash flows from operating activities. We generally fund growth capital expenditures with proceeds of borrowings under credit facilities, long-term debt, the issuance of additional Common Units or a combination thereof.

As of December 31, 2017, in addition to $306 million of cash on hand, we had available capacity under the ETP Credit Facilities of $2.51 billion. Based on our current estimates, we expect to utilize capacity under the ETP Credit Facilities, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2018; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

Cash Flows

Our internally generated cash flows may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions, and other factors.

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations" above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation, depletion and amortization expense and non-cash compensation expense. The increase in depreciation, depletion and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense resulted from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of derivative assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of inventories, and the timing of advances and deposits received from customers.

Following is a summary of operating activities by period:

Year Ended December 31, 2017

Cash provided by operating activities in 2017 was $4.49 billion and net income was $2.50 billion. The difference between net income and cash provided by operating activities in 2017 primarily consisted of non-cash items totaling $1.74 billion offset by net changes in operating assets and liabilities of $160 million. The non-cash activity in 2017 consisted primarily of depreciation, depletion and amortization of $2.33 billion, impairment losses of $920 million, impairment in unconsolidated affiliates of $313 million, non-cash compensation expense of $74 million, equity in earnings of unconsolidated affiliates of $156 million, and deferred income taxes benefit of $1.53 billion.

Year Ended December 31, 2016

Cash provided by operating activities in 2016 was $3.30 billion and net income was $583 million. The difference between net income and cash provided by operating activities in 2016 primarily consisted of non-cash items totaling $2.59 billion offset by net changes in operating assets and liabilities of $246 million. The non-cash activity in 2016 consisted primarily of depreciation, depletion and amortization of $1.99 billion, impairment losses of $813 million, impairment of an unconsolidated affiliate of $308 million, non-cash compensation expense of $80 million, equity in earnings of unconsolidated affiliates of $59 million, and deferred income taxes benefit of $169 million.

Year Ended December 31, 2015

Cash provided by operating activities in 2015 was $2.75 billion and net income was $1.49 billion. The difference between net income and cash provided by operating activities in 2015 primarily consisted of non-cash items totaling $2.01 billion offset by net changes in operating assets and liabilities of $1.17 billion. The non-cash activity in 2015 consisted primarily of depreciation, depletion and amortization of $1.93 billion, impairment losses of $339 million and inventory valuation adjustments of $58 million.

Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid for acquisitions, capital expenditures, cash distributions from our joint ventures, and cash proceeds from sales or contributions of assets or businesses. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Following is a summary of investing activities by period:

Year Ended December 31, 2017

Cash used in investing activities in 2017 was $5.47 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $8.31 billion. Additional detail related to our capital expenditures is provided in the table below. We received $2.00 billion and $1.48 billion in cash related to the Bakken equity sale to MarEn Bakken Company and the Rover equity sale to Blackstone Capital Partners, respectively, and paid $264 million in cash for all other acquisitions.

Year Ended December 31, 2016

Cash used in investing activities in 2016 was $6.39 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $7.48 billion. Additional detail related to our capital expenditures is provided in the table below. We paid net cash of $1.23 billion for acquisitions, including legacy Sunoco Logistics' Vitol Acquisition and the PennTex Acquisition, and received $2.20 billion in cash related to the contribution of our Sunoco, Inc. retail business to Sunoco LP.

Year Ended December 31, 2015

Cash used in investing activities in 2015 was $7.82 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $9.02 billion. Additional detail related to our capital expenditures is provided in the table below. We paid net cash of $804 million for acquisitions, including the acquisition of a noncontrolling interest.

The following is a summary of our capital expenditures (net of contributions in aid of construction costs) by period:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Year Ended December 31, 2017:			
Intrastate transportation and storage	$ 155	$ 20	$ 175
Interstate transportation and storage	645	81	726
Midstream	1,185	123	1,308
NGL and refined products transportation and services	2,899	72	2,971
Crude oil transportation and services	392	61	453
All other (including eliminations)	196	72	268
Total capital expenditures	$ 5,472	$ 429	$ 5,901
Year Ended December 31, 2016:			
Intrastate transportation and storage	$ 53	$ 23	$ 76
Interstate transportation and storage	191	89	280
Midstream	1,133	122	1,255
NGL and refined products transportation and services	2,150	48	2,198
Crude oil transportation and services	1,806	35	1,841
All other (including eliminations)	109	51	160
Total capital expenditures	$ 5,442	$ 368	$ 5,810
Year Ended December 31, 2015:			
Intrastate transportation and storage	$ 74	$ 31	$ 105
Interstate transportation and storage	741	125	866
Midstream	2,055	119	2,174
NGL and refined products transportation and services	2,798	55	2,853
Crude oil transportation and services	1,315	43	1,358
All other (including eliminations)	699	112	811
Total capital expenditures	$ 7,682	$ 485	$ 8,167

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods as a result of increases in the number of Common Units outstanding.

Following is a summary of financing activities by period:

Year Ended December 31, 2017

Cash provided by financing activities was $934 million in 2017. We received $2.28 billion in net proceeds from Common Unit offerings and $1.48 billion in net proceeds from the issuance of Preferred Units. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facilities, to fund capital expenditures and acquisitions, as well as for general partnership purposes. In 2017, we paid distributions of $3.47 billion to our partners and we paid distributions of $430 million to noncontrolling interests. In addition, we received capital contributions from noncontrolling interests of $1.21 billion. During 2017, we repurchased our outstanding Legacy Preferred Units for cash of $53 million and incurred debt issuance costs of $83 million.

Year Ended December 31, 2016

Cash provided by financing activities was $2.92 billion in 2016. We received $1.10 billion in net proceeds from Common Unit offerings, and our subsidiaries received $1.39 billion in net proceeds from the issuance of common units. Net proceeds from the offerings were used to repay outstanding borrowings under the ETLP Credit Facility, to fund capital expenditures and acquisitions,

as well as for general partnership purposes. In 2016, we had a net increase in our debt level of $4.24 billion primarily due to borrowings under our credit facilities in aggregate of $4.04 billion, legacy Sunoco Logistics' issuance of $550 million in aggregate principal amount of senior notes in July 2016 and $168 million of debt assumed by the Partnership in connection with the PennTex Acquisition, partially offset by repayments of long-term debt. In addition, we incurred debt issuance costs of $22 million. In 2016, we paid distributions of $3.54 billion to our partners and we paid distributions of $481 million to noncontrolling interests. In addition, we received capital contributions from noncontrolling interests of $236 million.

Year Ended December 31, 2015

Cash provided by financing activities was $4.94 billion in 2015. We received $1.43 billion in net proceeds from Common Unit offerings, and our subsidiaries received $1.52 billion in net proceeds from the issuance of common units. Net proceeds from the offerings were used to repay outstanding borrowings under the ETLP Credit Facility, to fund capital expenditures and acquisitions, as well as for general partnership purposes. In 2015, we had a net increase in our debt level of $4.85 billion primarily due to ETP's issuance of $2.50 billion and $3.00 billion in aggregate principal amount of senior notes in March 2015 and June 2015, respectively, and legacy Sunoco Logistics' issuance of $1.00 billion in aggregate principal amount of senior notes in November 2015. In addition, we incurred debt issuance costs of $63 million. In 2015, we paid distributions of $3.13 billion to our partners and we paid distributions of $338 million to noncontrolling interests. In addition, we received capital contributions from noncontrolling interest of $841 million.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	December 31,	
	2017	2016
ETP Senior Notes	$ 27,005	$ 24,855
Transwestern Senior Notes	575	657
Panhandle Senior Notes	785	1,085
Sunoco, Inc. Senior Notes	—	400
Revolving credit facilities:		
ETP $4.0 billion Revolving Credit Facility due December 2022	2,292	—
ETP $1.0 billion 364-Day Credit Facility due November 2018 [1]	50	—
ETLP $3.75 billion Revolving Credit Facility due November 2019	—	2,777
Legacy Sunoco Logistics $2.50 billion Revolving Credit Facility due March 2020	—	1,292
Legacy Sunoco Logistics $1.0 billion 364-Day Credit Facility due December 2017	—	630
Bakken Project $2.50 billion Credit Facility due August 2019	2,500	1,100
PennTex $275 million Revolving Credit Facility due December 2019	—	168
Other long-term debt	5	30
Unamortized premiums, net of discounts and fair value adjustments	61	116
Deferred debt issuance costs	(179)	(180)
Total debt	33,094	32,930
Less: current maturities of long-term debt	407	1,189
Long-term debt, less current maturities	$ 32,687	$ 31,741

[1] Borrowings under 364-day credit facilities were classified as long-term debt based on the Partnership's ability and intent to refinance such borrowings on a long-term basis.

The terms of our consolidated indebtedness and that of our subsidiaries are described in more detail below and in Note 6 to our consolidated financial statements.

Credit Facilities and Commercial Paper

ETP Credit Facilities

On December 1, 2017 the Partnership entered into a five-year, $4.0 billion unsecured revolving credit facility, which matures December 1, 2022 (the "ETP Five-Year Facility") and a $1.0 billion 364-day revolving credit facility that matures on November

30, 2018 (the "ETP 364-Day Facility") (collectively, the "ETP Credit Facilities"). The ETP Five-Year Facility contains an accordion feature, under which the total aggregate commitments may be increased up to $6.0 billion under certain conditions. We use the ETP Credit Facilities to provide temporary financing for our growth projects, as well as for general partnership purposes.

Borrowings under the ETP Credit Facilities are unsecured and initially guaranteed by Sunoco Logistics Partners Operations L.P. Borrowings under the ETP Credit Facilities will bear interest at a eurodollar rate or a base rate, at our option, plus an applicable margin. In addition, we will be required to pay a quarterly commitment fee to each lender equal to the product of the applicable rate and such lender's applicable percentage of the unused portion of the aggregate commitments under the ETP Credit Facilities. Concurrent with the closing of the ETP Credit Facilities, we repaid the entire amount outstanding and terminated our previously existing $3.75 billion ETLP Credit Facility and $2.50 billion Sunoco Logistics Credit Facility.

We typically repay amounts outstanding under the ETP Credit Facilities with proceeds from common unit offerings or long-term notes offerings. The timing of borrowings depends on the Partnership's activities and the cash available to fund those activities. The repayments of amounts outstanding under the ETP Credit Facilities depend on multiple factors, including market conditions and expectations of future working capital needs, and ultimately are a financing decision made by management. Therefore, the balance outstanding under the ETP Credit Facilities may vary significantly between periods. We do not believe that such fluctuations indicate a significant change in our liquidity position, because we expect to continue to be able to repay amounts outstanding under the ETP Credit Facilities with proceeds from common unit offerings or long-term note offerings.

As of December 31, 2017, the ETP Five-Year Facility had $2.29 billion outstanding, of which $2.01 billion was commercial paper. The amount available for future borrowings was $1.56 billion after taking into account letters of credit of $150 million. The weighted average interest rate on the total amount outstanding as of December 31, 2017 was 2.48%.

As of December 31, 2017, the ETP 364-Day Facility had $50 million outstanding, and the amount available for future borrowings was $950 million. The weighted average interest rate on the total amount outstanding as of December 31, 2017 was 5.00%.

Bakken Credit Facility

In August 2016, Energy Transfer Partners, L.P., Sunoco Logistics and Phillips 66 completed project-level financing of the Bakken Pipeline. The $2.50 billion credit facility is anticipated to provide substantially all of the remaining capital necessary to complete the projects and matures in August 2019 (the "Bakken Credit Facility"). As of December 31, 2017, the Bakken Credit Facility had $2.50 billion of outstanding borrowings. The weighted average interest rate on the total amount outstanding as of December 31, 2017 was 3.00%.

Covenants Related to Our Credit Agreements

Covenants Related to ETP

The agreements relating to the ETP senior notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions.

The ETP Credit Facilities contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries' ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in the ETP Credit Facilities) during certain Defaults (as defined in the ETP Credit Facilities) and during any Event of Default (as defined in the ETP Credit Facilities);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates; and
- enter into restrictive agreements.

The ETP Credit Facilities applicable margin and rate used in connection with the interest rates and commitment fees, respectively, are based on the credit ratings assigned to our senior, unsecured, non-credit enhanced long-term debt. The applicable margin for eurodollar rate loans under the ETP Five-Year Facility ranges from 1.125% to 2.000% and the applicable margin for base rate

loans ranges from 0.125% to 1.000%. The applicable rate for commitment fees under the ETP Five-Year Facility ranges from 0.125% to 0.300%. The applicable margin for eurodollar rate loans under the ETP 364-Day Facility ranges from 1.125% to 1.750% and the applicable margin for base rate loans ranges from 0.250% to 0.750%. The applicable rate for commitment fees under the ETP 364-Day Facility ranges from 0.125% to 0.225%.

The ETP Credit Facilities contain various covenants including limitations on the creation of indebtedness and liens, and related to the operation and conduct of our business. The ETP Credit Facilities also limit us, on a rolling four quarter basis, to a maximum Consolidated Funded Indebtedness to Consolidated EBITDA ratio, as defined in the underlying credit agreements, of 5.0 to 1, which can generally be increased to 5.5 to 1 during a Specified Acquisition Period. Our Leverage Ratio was 3.96 to 1 at December 31, 2017, as calculated in accordance with the credit agreements.

The agreements relating to the Transwestern senior notes contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

Covenants Related to Panhandle

Panhandle is not party to any lending agreement that would accelerate the maturity date of any obligation due to a failure to maintain any specific credit rating, nor would a reduction in any credit rating, by itself, cause an event of default under any of Panhandle's lending agreements. Financial covenants exist in certain of Panhandle's debt agreements that require Panhandle to maintain a certain level of net worth, to meet certain debt to total capitalization ratios and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. A failure by Panhandle to satisfy any such covenant would give rise to an event of default under the associated debt, which could become immediately due and payable if Panhandle did not cure such default within any permitted cure period or if Panhandle did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

Panhandle's restrictive covenants include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions, cross default and cross-acceleration and prepayment of debt provisions. A breach of any of these covenants could result in acceleration of Panhandle's debt and other financial obligations and that of its subsidiaries.

In addition, Panhandle and/or its subsidiaries are subject to certain additional restrictions and covenants. These restrictions and covenants include limitations on additional debt at some of its subsidiaries; limitations on the use of proceeds from borrowing at some of its subsidiaries; limitations, in some cases, on transactions with its affiliates; limitations on the incurrence of liens; potential limitations on the abilities of some of its subsidiaries to declare and pay dividends and potential limitations on some of its subsidiaries to participate in Panhandle's cash management program; and limitations on Panhandle's ability to prepay debt.

Covenants Related to Bakken Credit Facility

The Bakken Credit Facility contains standard and customary covenants for a financing of this type, subject to materiality, knowledge and other qualifications, thresholds, reasonableness and other exceptions. These standard and customary covenants include, but are not limited to:

- prohibition of certain incremental secured indebtedness;
- prohibition of certain liens / negative pledge;
- limitations on uses of loan proceeds;
- limitations on asset sales and purchases;
- limitations on permitted business activities;
- limitations on mergers and acquisitions;
- limitations on investments;
- limitations on transactions with affiliates; and
- maintenance of commercially reasonable insurance coverage.

A restricted payment covenant is also included in the Bakken Credit Facility which requires a minimum historic debt service coverage ratio ("DSCR") of not less than 1.20 to 1 (the "Minimum Historic DSCR") with respect each 12-month period following the commercial in-service date of the Dakota Access and ETCO Project in order to make certain restricted payments thereunder.

Compliance with our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2017.

Off-Balance Sheet Arrangements

Contingent Residual Support Agreement – AmeriGas

In connection with the closing of the contribution of its propane operations in January 2012, ETP previously provided contingent residual support of certain debt obligations of AmeriGas. AmeriGas has subsequently repaid the remainder of the related obligations and ETP no longer provides contingent residual support for any AmeriGas notes.

Guarantee of Sunoco LP Notes

In connection with previous transactions whereby Retail Holdings contributed assets to Sunoco LP, Retail Holdings provided a limited contingent guarantee of collection, but not of payment, to Sunoco LP with respect to (i) $800 million principal amount of 6.375% senior notes due 2023 issued by Sunoco LP, (ii) $800 million principal amount of 6.25% senior notes due 2021 issued by Sunoco LP and (iii) $2.035 billion aggregate principal for Sunoco LP's term loan due 2019. In December 2016, Retail Holdings contributed its interests in Sunoco LP, along with the assignment of the guarantee of Sunoco LP's senior notes, to its subsidiary, ETC M-A Acquisition LLC ("ETC M-A").

On January 23, 2018, Sunoco LP redeemed the previously guaranteed senior notes and issued the following notes for which ETC M-A has also guaranteed collection with respect to the payment of principal amounts:

- $1.00 billion aggregate principal amount of 4.875%, senior notes due 2023;
- $800 million aggregate principal amount of 5.50% senior notes due 2026; and
- $400 million aggregate principal amount of 5.875% senior notes due 2028.

Under the guarantee of collection, ETC M-A would have the obligation to pay the principal of each series of notes once all remedies, including in the context of bankruptcy proceedings, have first been fully exhausted against Sunoco LP with respect to such payment obligation, and holders of the notes are still owed amounts in respect of the principal of such notes. ETC M-A will not otherwise be subject to the covenants of the indenture governing the notes.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2017:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 33,212	$ 1,700	$ 5,375	$ 6,746	$ 19,391
Interest on long-term debt[1]	22,204	1,626	2,873	2,447	15,258
Payments on derivatives	223	84	139	—	—
Purchase commitments[2]	3,605	3,443	99	35	28
Transportation, natural gas storage and fractionation contracts	25	19	6	—	—
Operating lease obligations	257	39	73	53	92
Other[3]	185	32	56	45	52
Total[4]	$ 59,711	$ 6,943	$ 8,621	$ 9,326	$ 34,821

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2017. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2017. To the extent interest rates change, our contractual obligations for interest payments will change. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for further discussion.

(2) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for refined product and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the December 31, 2017 market price of the applicable commodity applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. Our estimated future fixed price contract payment obligations are based on the contracted fixed price under each commodity contract. Obligations shown in the table represent estimated payment obligations under these contracts for the periods indicated.

(3) Expected contributions to fund our pension and postretirement benefit plans were included in "Other" above. Environmental liabilities, asset retirement obligations, unrecognized tax benefits, contingency accruals and deferred revenue, which were included in "Other non-current liabilities" in our consolidated balance sheets, were excluded from the table above as the amounts do not represent contractual obligations or, in some cases, the amount and/or timing of the cash payments is uncertain.

(4) Excludes non-current deferred tax liabilities of $2.88 billion due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

Cash Distributions Paid by ETP

Under the Partnership's limited partnership agreement, within 45 days after the end of each quarter, the Partnership distributes all cash on hand at the end of the quarter, less reserves established by the general partner in its discretion. This is defined as "available cash" in the partnership agreement. The general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct the Partnership's business. The Partnership will make quarterly distributions to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to the general partner.

If cash distributions exceed $0.0833 per unit in a quarter, the holders of the incentive distribution rights receive increasing percentages, up to 48 percent, of the cash distributed in excess of that amount. These distributions are referred to as "incentive distributions."

The following table shows the target distribution levels and distribution "splits" between the general and limited partners and the holders of the Partnership's incentive distribution rights ("IDRs"):

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	IDRs	Partners (1)
Minimum Quarterly Distribution	$0.0750	—%	100%
First Target Distribution	up to $0.0833	—%	100%
Second Target Distribution	above $0.0833 up to $0.0958	13%	87%
Third Target Distribution	above $0.0958 up to $0.2638	35%	65%
Thereafter	above $0.2638	48%	52%

(1) Includes general partner and limited partner interests, based on the proportionate ownership of each.

Distributions on common units declared and paid by ETP and Sunoco Logistics during the pre-merger periods were as follows:

Quarter Ended	ETP	Sunoco Logistics
December 31, 2014	$ 0.6633	$ 0.4000
March 31, 2015	0.6767	0.4190
June 30, 2015	0.6900	0.4380
September 30, 2015	0.7033	0.4580
December 31, 2015	0.7033	0.4790
March 31, 2016	0.7033	0.4890
June 30, 2016	0.7033	0.5000
September 30, 2016	0.7033	0.5100
December 31, 2016	0.7033	0.5200

Distributions on common units declared and paid by Post-Merger ETP were as follows:

Quarter Ended	Record Date	Payment Date	Rate
March 31, 2017	May 10, 2017	May 16, 2017	$ 0.5350
June 30, 2017	August 7, 2017	August 15, 2017	0.5500
September 30, 2017	November 7, 2017	November 14, 2017	0.5650
December 31, 2017	February 8, 2018	February 14, 2018	0.5650

Distributions declared and paid by ETP to the preferred unitholders were as follows:

			Distribution per Preferred Unit	
Quarter Ended	Record Date	Payment Date	Series A	Series B
December 31, 2017	February 1, 2018	February 15, 2018	$ 15.451	$ 16.378

The total amounts of distributions declared and paid during the periods presented (all from Available Cash from our operating surplus and are shown in the year with respect to which they relate):

	Years Ended December 31,				
	ETP	Energy Transfer Partners, L.P.		Sunoco Logistics	
	2017	2016	2015	2016	2015
Common Units held by public	$ 2,435	$ 2,168	$ 1,970	$ 485	$ 344
Common Units held by ETP	—	—	—	135	120
Common Units held by ETE	61	28	54	—	—
Class H Units held by ETE	—	357	263	—	—
General Partner interest	16	32	31	15	12
Incentive distributions	1,638	1,363	1,261	397	281
IDR relinquishments [1]	(656)	(409)	(111)	(15)	—
Series A Preferred Units	15	—	—	—	—
Series B Preferred Units	9	—	—	—	—
Total distributions declared to partners	$ 3,518	$ 3,539	$ 3,468	$ 1,017	$ 757

(1) Net of Class I unit distributions

In connection with previous transactions, ETE has agreed to relinquish certain amounts of incentive distributions, including the following amounts of incentive distributions in future periods. These amounts include incentive distribution relinquishments related to both legacy ETP and legacy Sunoco Logistics, both of which are applicable to the combined post-merger ETP:

	Total Year
2018	$ 153
2019	128
Each year beyond 2019	33

Recent Accounting Pronouncements

ASU 2014-09

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle 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. The Partnership adopted ASU 2014-09 on January 1, 2018. The Partnership applied the cumulative catchup transition method and recognized the cumulative effect of the retrospective application of the standard. The effect of the retrospective application of the standard was not material.

For future periods, we expect that the adoption of this standard will result in a change to revenues with offsetting changes to costs associated primarily with the designation of certain of our midstream segment agreements to be in-substance supply agreements, requiring amounts that had previously been reported as revenue under these agreements to be reclassified to a reduction of cost of sales. Changes to revenues along with offsetting changes to costs will also occur due to changes in the accounting for noncash consideration in multiple of our reportable segments, as well as fuel usage and loss allowances. None of these changes is expected to have a material impact on net income.

ASU 2016-02

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, *Leases (Topic 842)* ("ASU 2016-02"), which establishes the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. The Partnership expects to adopt ASU 2016-02 in the first quarter of 2019 and is currently evaluating the impact that adopting this new standard will have on the consolidated financial statements and related disclosures.

ASU 2016-16

On January 1, 2018, the Partnership adopted Accounting Standards Update No. 2016-16, *Income Taxes (Topic 740): Intra-entity Transfers of Assets Other Than Inventory* ("ASU 2016-16"), which requires that entities recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The amendments in this update do not change GAAP for the pre-tax effects of an intra-entity asset transfer under Topic 810, Consolidation, or for an intra-entity transfer of inventory. We do not anticipate a material impact to our financial position or results of operations as a result of the adoption of this standard.

ASU 2017-04

In January 2017, the FASB issued ASU No. 2017-04 "*Intangibles-Goodwill and other (Topic 350): Simplifying the test for goodwill impairment.*" The amendments in this update remove the second step of the two-step test currently required by Topic 350. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance did not amend the optional qualitative assessment of goodwill impairment. The standard requires prospective application and therefore will only impact periods subsequent to the adoption. The Partnership adopted this ASU for its annual goodwill impairment test in the fourth quarter of 2017.

ASU 2017-12

In August 2017, the FASB issued ASU No. 2017-12 " *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities.*" The amendments in this update improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. In addition, the amendments in this update

make certain targeted improvements to simplify the application of the hedge accounting guidance in current GAAP. This ASU is effective for financial statements issued for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. The Partnership is currently evaluating the impact that adopting this new standard will have on the consolidated financial statements and related disclosures.

Estimates and Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules, and we believe the proper implementation and consistent application of the accounting rules are critical. Our critical accounting policies are discussed below. For further details on our accounting policies see Note 2 to our consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream, NGL and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the operating results estimated for the year ended December 31, 2017 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation, depletion and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Revenue Recognition. Revenues for sales of natural gas and NGLs are recognized at the later of the time of delivery of the product to the customer or the time of sale. Revenues from service labor, transportation, treating, compression and gas processing, are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available.

Our intrastate transportation and storage and interstate transportation and storage segments' results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly. Excess fuel retained after consumption is typically valued at market prices.

Our intrastate transportation and storage segment also generates revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from our marketing operations, and from producers at the wellhead.

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and segment margins principally under fee-based or other arrangements in which we receive a fee for natural

gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

We conduct marketing activities in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

We have a risk management policy that provides for oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to senior management and predefined limits and authorizations set forth in our risk management policy.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot prices and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

NGL storage and pipeline transportation revenues are recognized when services are performed or products are delivered, respectively. Fractionation and processing revenues are recognized when product is either loaded into a truck or injected into a third-party pipeline, which is when title and risk of loss pass to the customer.

In our natural gas compression business, revenue is recognized for compressor packages and technical service jobs using the completed contract method which recognizes revenue upon completion of the job. Costs incurred on a job are deducted at the time revenue is recognized.

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

Regulatory Assets and Liabilities. Our interstate transportation and storage segment is subject to regulation by certain state and federal authorities, and certain subsidiaries in that segment have accounting policies that conform to the accounting requirements

and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of our regulated entities to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be assessed and potentially eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Accounting for Derivative Instruments and Hedging Activities. We utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL and refined products. These contracts consist primarily of futures and swaps. In addition, prior to the contribution of our retail propane activities to AmeriGas, we used derivatives to limit our exposure to propane market prices.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, the change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

We utilize published settlement prices for exchange-traded contracts, quotes provided by brokers, and estimates of market prices based on daily contract activity to estimate the fair value of these contracts. Changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" for further discussion regarding our derivative activities.

Fair Value of Financial Instruments. We have commodity derivatives, interest rate derivatives and embedded derivatives in our preferred units that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. Derivatives related to the embedded derivatives in our preferred units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected value, and are considered level 3. See further information on our fair value assets and liabilities in Note 2 of our consolidated financial statements.

Impairment of Long-Lived Assets, Goodwill, Intangible Assets and Investments in Unconsolidated Affiliates. Long-lived assets are required to be tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. Goodwill and intangibles with indefinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment of an investment in an unconsolidated affiliate is recognized when circumstances indicate that a decline in the investment value is other than temporary. An impairment loss should be recognized only if the carrying amount of the asset/goodwill is not recoverable and exceeds its fair value.

In order to test for recoverability when performing a quantitative impairment test, we must make estimates of projected cash flows related to the asset, which include, but are not limited to, assumptions about the use or disposition of the asset, estimated remaining life of the asset, and future expenditures necessary to maintain the asset's existing service potential. In order to determine fair value, we make certain estimates and assumptions, including, among other things, changes in general economic conditions in regions in which our markets are located, the availability and prices of natural gas, our ability to negotiate favorable sales agreements, the risks that natural gas exploration and production activities will not occur or be successful, our dependence on certain significant customers and producers of natural gas, and competition from other companies, including major energy producers. While we believe we have made reasonable assumptions to calculate the fair value, if future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations.

The Partnership determined the fair value of its reporting units using a weighted combination of the discounted cash flow method and the guideline company method. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Such estimates and assumptions include revenue growth rates, operating margins, weighted average costs of capital and future market conditions, among others. The Partnership believes the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. Under the discounted cash flow method, the Partnership determined fair value based on estimated future cash flows of each reporting unit including estimates for capital expenditures, discounted to present value using the risk-adjusted industry rate, which reflect the overall level of inherent risk of the reporting unit. Cash flow projections are derived from one year budgeted amounts and five year operating forecasts plus an estimate of later period cash flows, all of which are evaluated by management. Subsequent period cash flows are developed for each reporting unit using growth rates that management believes are reasonably likely to occur. Under the guideline company method, the Partnership determined the estimated fair value of each of our reporting units by applying valuation multiples of comparable publicly-traded companies to each reporting unit's projected EBITDA and then averaging that estimate with similar historical calculations using a three year average. In addition, the Partnership estimated a reasonable control premium representing the incremental value that accrues to the majority owner from the opportunity to dictate the strategic and operational actions of the business.

One key assumption for the measurement of an impairment is management's estimate of future cash flows and EBITDA. These estimates are based on the annual budget for the upcoming year and forecasted amounts for multiple subsequent years. The annual budget process is typically completed near the annual goodwill impairment testing date, and management uses the most recent information for the annual impairment tests. The forecast is also subjected to a comprehensive update annually in conjunction with the annual budget process and is revised periodically to reflect new information and/or revised expectations. The estimates of future cash flows and EBITDA are subjective in nature and are subject to impacts from the business risks described in "Item 1A. Risk Factors." Therefore, the actual results could differ significantly from the amounts used for goodwill impairment testing, and significant changes in fair value estimates could occur in a given period. Such changes in fair value estimates could result in additional impairments in future periods; however, management does not believe that any of the goodwill balances in its reporting units as of December 31, 2017 is at significant risk of impairment. Therefore, the actual results could differ significantly from the amounts used for goodwill impairment testing, and significant changes in fair value estimates could occur in a given period, resulting in additional impairments.

Management does not believe that any of the goodwill balances in its reporting units is currently at significant risk of impairment; however, of the $3.1 billion of goodwill on the Partnership's consolidated balance sheet as of December 31, 2017, approximately $1.0 billion is recorded in reporting units for which the estimated fair value exceeded the carrying value by less than 20% in the most recent quantitative test.

During the year ended December 31, 2017, the Partnership recorded following impairments:

- A $223 million impairment was recorded related to the goodwill associated with CDM. In January 2018, the Partnership announced the contribution of CDM to USAC. Based on the Partnership's anticipated proceeds in the contribution transaction, the implied fair value of the CDM reporting unit was less than the Partnership's carrying value. As the Partnership believes that the contribution consideration also represented an appropriate estimate of fair value as of the 2017 annual impairment test date, the Partnership recorded an impairment for the difference between the carrying value and the fair value of the reporting unit. Subsequent to the impairment, a total of $253 million of goodwill remains in the CDM reporting unit, which amount is subject to further impairment based on changes in the contribution transaction prior to closing or any other factors affecting the fair value of the CDM reporting unit. Assuming the contribution transaction closes, the remaining CDM goodwill balance will be derecognized; if the transaction does not close, then the CDM goodwill balance will remain on the Partnership's consolidated balance sheet and will continue to be tested for impairment in the future.
- A $262 million impairment was recorded related to the goodwill associated with the Partnership's interstate transportation and storage reporting units, and a $229 million impairment was recorded related to the goodwill associated with the general partner of Panhandle in the all other segment. These impairments were due to a reduction in management's forecasted future

cash flows from the related reporting units, which reduction reflected the impacts discussed in "Results of Operations" above, along with the impacts of re-contracting assumptions related to future periods.

- A $79 million impairment was recorded related to the goodwill associated the Partnership's refined products transportation and services reporting unit. Subsequent to the Sunoco Logistics Merger, the Partnership restructured the internal reporting of legacy Sunoco Logistics' business to be consistent with the internal reporting of legacy ETP. Subsequent to this reallocation the carrying value of certain refined products reporting units was less than the estimated fair value due to a reduction in management's forecasted future cash flows from the related reporting units, and the goodwill associated with those reporting units was fully impaired. No goodwill remained in the respective reporting units subsequent to the impairment.
- A $127 million impairment of property, plant and equipment related to Sea Robin primarily due to a reduction in expected future cash flows due to an increase during 2017 in insurance costs related to offshore assets.
- A $141 million impairment of the Partnership's equity method investment in FEP. The Partnership concluded that the carrying value of its investment in FEP was other than temporarily impaired based on an anticipated decrease in production in the Fayetteville basin and a customer re-contracting with a competitor during 2017.
- A $172 million impairment of the Partnership's equity method investment in HPC primarily due to a decrease in projected future revenues and cash flows driven be the bankruptcy of one of HPC's major customers in 2017 and an expectation that contracts expiring in the next few years will be renewed at lower tariff rates and lower volumes.

During the year ended December 31, 2016, the Partnership recorded following goodwill impairments:

- A $638 million goodwill impairment and a $133 million impairment to property, plant and equipment were recorded in the interstate transportation and storage segment primarily due to decreases in projected future revenues and cash flows driven by changes in the markets that these assets serve.
- A $32 million goodwill impairment was recorded in the midstream segment primarily due to decreases in projected future revenues and cash flows driven by declines in commodity prices.
- A $308 million impairment of the Partnership's equity method investment in MEP. The Partnership concluded that the carrying value of its investment in MEP was other than temporarily impaired based on commercial discussions with current and potential shippers on MEP during 2016, which negatively affected the outlook for long-term transportation contract rates.

During the year ended December 31, 2015, the Partnership recorded following goodwill impairments:

- A $99 million goodwill impairment related to Transwestern primarily due to market declines in current and expected future commodity prices in the fourth quarter of 2015.
- A $106 million goodwill impairment, a $24 million impairment of intangible assets, and a $110 million impairment to property, plant and equipment related to Lone Star Refinery Services primarily due to changes in assumptions related to potential future revenues and market declines in current and expected future commodity prices, as well as economic obsolescence identified as a result of low utilization.

Except for the 2017 impairment of the goodwill associated with CDM, as discussed above, the goodwill impairments recorded by the Partnership during the years ended December 31, 2017, 2016 and 2015 represented all of the goodwill within the respective reporting units.

Property, Plant and Equipment. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the consolidated statement of operations. Depreciation of property, plant and equipment is provided using the straight-line method based on their estimated useful lives ranging from 1 to 99 years. Changes in the estimated useful lives of the assets could have a material effect on our results of operation. We do not anticipate future changes in the estimated useful lives of our property, plant and equipment.

Asset Retirement Obligations. We have determined that we are obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of certain assets. The fair value of any ARO is determined based on estimates and assumptions related to retirement costs, which the Partnership bases on historical retirement costs, future inflation rates and credit-adjusted risk-free interest rates. These fair value assessments are considered to be Level 3 measurements, as they

are based on both observable and unobservable inputs. Changes in the liability are recorded for the passage of time (accretion) or for revisions to cash flows originally estimated to settle the ARO.

An ARO is required to be recorded when a legal obligation to retire an asset exists and such obligation can be reasonably estimated. We will record an asset retirement obligation in the periods in which management can reasonably estimate the settlement dates.

Except for certain amounts discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2017 and 2016, in most cases because the settlement dates were indeterminable. Although a number of other onshore assets in Panhandle's system are subject to agreements or regulations that give rise to an ARO upon Panhandle's discontinued use of these assets, AROs were not recorded because these assets have an indeterminate removal or abandonment date given the expected continued use of the assets with proper maintenance or replacement. Sunoco, Inc. has legal asset retirement obligations for several other assets at its previously owned refineries, pipelines and terminals, for which it is not possible to estimate when the obligations will be settled. Consequently, the retirement obligations for these assets cannot be measured at this time. At the end of the useful life of these underlying assets, Sunoco, Inc. is legally or contractually required to abandon in place or remove the asset. We believe we may have additional asset retirement obligations related to its pipeline assets and storage tanks, for which it is not possible to estimate whether or when the retirement obligations will be settled. Consequently, these retirement obligations cannot be measured at this time.

Individual component assets have been and will continue to be replaced, but the pipeline and the natural gas gathering and processing systems will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities, management expects supply and demand to exist for the foreseeable future. We have in place a rigorous repair and maintenance program that keeps the pipelines and the natural gas gathering and processing systems in good working order. Therefore, although some of the individual assets may be replaced, the pipelines and the natural gas gathering and processing systems themselves will remain intact indefinitely.

Long-lived assets related to AROs aggregated $2 million and $14 million, and were reflected as property, plant and equipment on our balance sheet as of December 31, 2017 and 2016, respectively. In addition, the Partnership had $21 million and $13 million of legally restricted funds for the purpose of settling AROs that was reflected as other non-current assets as of December 31, 2017 and 2016, respectively.

Pensions and Other Postretirement Benefit Plans. We are required to measure plan assets and benefit obligations as of its fiscal year-end balance sheet date. We recognize the changes in the funded status of our defined benefit postretirement plans through AOCI or are reflected as a regulatory asset or regulatory liability for regulated subsidiaries.

The calculation of the net periodic benefit cost and benefit obligation requires the use of a number of assumptions. Changes in these assumptions can have a significant effect on the amounts reported in the financial statements. The Partnership believes that the two most critical assumptions are the assumed discount rate and the expected rate of return on plan assets.

The discount rate is established by using a hypothetical portfolio of high-quality debt instruments that would provide the necessary cash flows to pay the benefits when due. Net periodic benefit cost and benefit obligation increases and equity correspondingly decreases as the discount rate is reduced.

The expected rate of return on plan assets is based on long-term expectations given current investment objectives and historical results. Net periodic benefit cost increases as the expected rate of return on plan assets is correspondingly reduced.

Legal Matters. We are subject to litigation and regulatory proceedings as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from claims, orders, judgments or settlements. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. We expense legal costs as incurred, and all recorded legal liabilities are revised, as required, as better information becomes available to us. The factors we consider when recording an accrual for contingencies include, among others: (i) the opinions and views of our legal counsel; (ii) our previous experience; and (iii) the decision of our management as to how we intend to respond to the complaints.

For more information on our litigation and contingencies, see Note 11 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" in this report.

Environmental Remediation Activities. The Partnership's accrual for environmental remediation activities reflects anticipated work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. The accrual for known claims is undiscounted and is based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. It is often extremely difficult to develop reasonable estimates of future site remediation costs due to changing regulations, changing technologies and their associated costs,

and changes in the economic environment. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated accruals for environmental remediation activities.

Losses attributable to unasserted claims are generally reflected in the accruals on an undiscounted basis, to the extent they are probable of occurrence and reasonably estimable. We have established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

In general, each remediation site/issue is evaluated individually based upon information available for the site/issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (e.g., service station sites) in determining the amount of probable loss accrual to be recorded. The Partnership's estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance requires that the minimum of the range be accrued. Accordingly, the low end of the range often represents the amount of loss which has been recorded.

In addition to the probable and estimable losses which have been recorded, management believes it is reasonably possible (i.e., less than probable but greater than remote) that additional environmental remediation losses will be incurred. At December 31, 2017, the aggregate of the estimated maximum reasonably possible losses, which relate to numerous individual sites, totaled approximately $5 million. This estimate of reasonably possible losses comprises estimates for remediation activities at current logistics and retail assets and, in many cases, reflects the upper end of the loss ranges which are described above. Such estimates include potentially higher contractor costs for expected remediation activities, the potential need to use more costly or comprehensive remediation methods and longer operating and monitoring periods, among other things.

Total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of the Partnership's liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur, would likely extend over many years. Management believes that the Partnership's exposure to adverse developments with respect to any individual site is not expected to be material. However, if changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could impact multiple facilities, formerly owned facilities and third-party sites at the same time. As a result, from time to time, significant charges against income for environmental remediation may occur; however, management does not believe that any such charges would have a material adverse impact on the Partnership's consolidated financial position.

Deferred Income Taxes. ETP recognizes benefits in earnings and related deferred tax assets for net operating loss carryforwards ("NOLs") and tax credit carryforwards. If necessary, a charge to earnings and a related valuation allowance are recorded to reduce deferred tax assets to an amount that is more likely than not to be realized by the Partnership in the future. Deferred income tax assets attributable to state and federal NOLs and federal tax alternative minimum tax credit carryforwards totaling $604 million have been included in ETP's consolidated balance sheet as of December 31, 2017. All of the deferred income tax assets attributable to state and federal NOL benefits expire before 2037 as more fully described below. The state NOL carryforward benefits of $266 million ($210 million net of federal benefit) begin to expire in 2018 with a substantial portion expiring between 2031 and 2037. The federal NOLs of $1.57 billion ($331 million in benefits) will expire in 2031 and 2037. Federal alternative minimum tax credit carryforwards of $62 million remained at December 31, 2017. We have determined that a valuation allowance totaling $236 million ($186 million net of federal income tax effects) is required for the state NOLs at December 31, 2017 primarily due to significant restrictions on their use in the Commonwealth of Pennsylvania. In making the assessment of the future realization of the deferred tax assets, we rely on future reversals of existing taxable temporary differences, tax planning strategies and forecasted taxable income based on historical and projected future operating results. The potential need for valuation allowances is regularly reviewed by management. If it is more likely than not that the recorded asset will not be realized, additional valuation allowances which increase income tax expense may be recognized in the period such determination is made. Likewise, if it is more likely than not that additional deferred tax assets will be realized, an adjustment to the deferred tax asset will increase income in the period such determination is made.

Forward-Looking Statements

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this annual report, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "estimate," "intend," "could," "believe," "may," "will" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our processing and treating facilities;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;

- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third-party contractors;
- the availability and cost of capital and our ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which we own less than a controlling interests, including risks related to management actions at such entities that we may not be able to control or exert influence;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;
- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations; and
- the costs and effects of legal and administrative proceedings.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risks described under "Item 1A. Risk Factors" in this annual report. Any forward-looking statement made by us in this Annual Report on Form 10-K is based only on information currently available to us and speaks only as of the date on which it is made. We undertake no obligation to publicly update any forward-looking statement, whether written or oral, that may be made from time to time, whether as a result of new information, future developments or otherwise.

Inflation

Interest rates on existing and future credit facilities and future debt offerings could be significantly higher than current levels, causing our financing costs to increase accordingly. Although increased financing costs could limit our ability to raise funds in the capital markets, we expect to remain competitive with respect to acquisitions and capital projects since our competitors would face similar circumstances.

Inflation in the United States has been relatively low in recent years and has not had a material effect on our results of operations. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. Our operating revenues and costs are influenced to a greater extent by commodity price changes. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along a portion of increased costs to our customers in the form of higher fees.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.

We use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. At hedge inception, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract. Changes in the spreads between the forward natural gas prices and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized.

We use futures, swaps and options to hedge the sales price of natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation and storage segment. These contracts are not designated as hedges for accounting purposes.

We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes we retain for fees in our midstream segment whereby our subsidiaries generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price for the residue gas and NGL. These contracts are not designated as hedges for accounting purposes.

We utilize swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs to manage our storage facilities and the purchase and sale of purity NGL. These contracts are not designated as hedges for accounting purposes.

We use financial commodity derivatives to take advantage of market opportunities in our trading activities which complement our transportation and storage segment's operations and are netted in cost of products sold in our consolidated statements of operations. We also have trading and marketing activities related to power and natural gas in our all other segment which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

The table below summarizes our commodity-related financial derivative instruments and fair values, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Dollar amounts are presented in millions.

	December 31, 2017			December 31, 2016		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (BBtu):						
Fixed Swaps/Futures	1,078	$ —	$ —	(683)	$ —	$ —
Basis Swaps IFERC/NYMEX[1]	48,510	2	1	2,243	(1)	—
Options – Puts	13,000	—	—	—	—	—
Power (Megawatt):						
Forwards	435,960	1	1	391,880	(1)	1
Futures	(25,760)	—	—	109,564	—	—
Options – Puts	(153,600)	—	1	(50,400)	—	—
Options – Calls	137,600	—	—	186,400	1	—
Crude (MBbls) – Futures	—	1	—	(617)	(4)	6
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	4,650	(13)	4	10,750	2	—
Swing Swaps IFERC	87,253	(2)	1	(5,663)	(1)	1
Fixed Swaps/Futures	(4,700)	(1)	2	(52,653)	(27)	19
Forward Physical Contracts	(145,105)	6	41	(22,492)	1	8
Natural Gas Liquid (MBbls) – Forwards/Swaps	6,679	1	25	(5,787)	(40)	35
Refined Products (MBbls) – Futures	(3,783)	(25)	4	(2,240)	(16)	17
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(39,770)	(2)	—	(36,370)	2	1
Fixed Swaps/Futures	(39,770)	14	11	(36,370)	(26)	14

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

The fair values of the commodity-related financial positions have been determined using independent third-party prices, readily available market information and appropriate valuation techniques. Non-trading positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above tables. Price-risk sensitivities were calculated by assuming a theoretical 10% change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in net income or in other comprehensive income. In the event of an actual 10% change in prompt month

natural gas prices, the fair value of our total derivative portfolio may not change by 10% due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

Interest Rate Risk

As of December 31, 2017, we had $5.11 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $51 million annually; however, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock-in the rate on a portion of anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes:

		Notional Amount Outstanding	
Term	Type[1]	December 31, 2017	December 31, 2016
July 2017[2]	Forward-starting to pay a fixed rate of 3.90% and receive a floating rate	$ —	$ 500
July 2018[2]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	300	200
July 2019[2]	Forward-starting to pay a fixed rate of 3.64% and receive a floating rate	300	200
July 2020[2]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	—
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	1,200
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	300

(1) Floating rates are based on 3-month LIBOR.

(2) Represents the effective date. These forward-starting swaps have terms of 30 years with a mandatory termination date the same as the effective date.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $236 million as of December 31, 2017. For the $1.50 billion of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $15 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

Credit Risk

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may, at times, require collateral under certain circumstances to mitigate credit risk as necessary. The Partnership also uses industry standard commercial agreements which allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, gas and electric utilities, midstream companies and independent power generators. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheets and recognized in net income or other comprehensive income.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements starting on page F-1 of this report are incorporated by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of ETP LLC, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a–15(e) and 15d–15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of ETP LLC, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2017.

Management's Report on Internal Control over Financial Reporting

The management of Energy Transfer Partners, L.P. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of ETP LLC, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 2013 *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO framework").

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2017.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2017, as stated in their report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of Energy Transfer Partners, L.L.C. and
Unitholders of Energy Transfer Partners, L.P.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2017, based on criteria established in the 2013 *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in the 2013 *Internal Control – Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2017, and our report dated February 23, 2018 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ GRANT THORNTON LLP

Dallas, Texas
February 23, 2018

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a–15(f) or Rule 15d–15(f)) that occurred in the three months ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

Our General Partner manages and directs all of our activities. On April 28, 2017, concurrent with the merger of legacy ETP and legacy Sunoco Logistics, the general partner of legacy Sunoco Logistics, Sunoco Partners LLC, merged with and into the general partner of legacy ETP, Energy Transfer Partners GP, L.P. ("ETP GP"), with ETP GP surviving as the new general partner of the Partnership. The activities of ETP GP are managed and directed by its general partner, ETP LLC, which we refer to in this Item as "our General Partner." Our officers and directors are officers and directors of ETP LLC. ETE, as the sole member of ETP LLC, is entitled under the limited liability company agreement of ETP LLC to appoint all of the directors of ETP LLC. This agreement provides that the Board of Directors of ETP LLC shall consist of not more than 13 persons, at least three of whom are required to qualify as independent directors. As of December 31, 2017, our Board of Directors was comprised of six persons, three of whom qualified as "independent" under the NYSE's corporate governance standards. Our Board of Directors determined that Messrs. Collins, Grimm and Skidmore all met the NYSE's independence requirements. Our current directors who are not independent consist of Kelcy L. Warren, ETP LLC's Chief Executive Officer, and Matthew S. Ramsey, ETP LLC's President and Chief Operating Officer, as well as Marshall S. McCrea III, the Group Chief Operating Officer and Chief Commercial Officer of ETE's general partner.

As a limited partnership, we are not required by the rules of the NYSE to seek Unitholder approval for the election of any of our directors. We believe that ETE has appointed as directors individuals with experience, skills and qualifications relevant to the business of the Partnership, such as experience in energy or related industries or with financial markets, expertise in natural gas operations or finance, and a history of service in senior leadership positions. We do not have a formal process for identifying director nominees, nor do we have a formal policy regarding consideration of diversity in identifying director nominees, but we believe ETE has endeavored to assemble a group of individuals with the qualities and attributes required to provide effective oversight of the Partnership.

Board Leadership Structure. We have no policy requiring either that the positions of the Chairman of the Board and the Chief Executive Officer, or CEO, be separate or that they be occupied by the same individual. The Board of Directors believes that this issue is properly addressed as part of the succession planning process and that a determination on this subject should be made when it elects a new chief executive officer or at such other times as when consideration of the matter is warranted by circumstances. Currently, the Board of Directors believes that the CEO is best situated to serve as Chairman because he is the director most familiar with the Partnership's business and industry, and most capable of effectively identifying strategic priorities and leading the discussion and execution of strategy. Independent directors and management have different perspectives and roles in strategy development. Our independent directors bring experience, oversight and expertise from outside the Partnership and from a variety of industries, while the CEO brings extensive experience and expertise specifically related to the Partnership's business. The Board of Directors believes that the current combined role of Chairman and CEO promotes strategy development and execution, and facilitates information flow between management and the Board of Directors, which are essential to effective governance.

One of the key responsibilities of the Board of Directors is to develop strategic direction and hold management accountable for the execution of strategy once it is developed. The Board of Directors believes the current combined role of Chairman and CEO, together with a majority of independent board members, is in the best interest of Unitholders because it provides the appropriate balance between strategy development and independent oversight of management.

Risk Oversight. Our Board of Directors generally administers its risk oversight function through the board as a whole. Our CEO, who reports to the Board of Directors, and the other executive officers, who report to our CEO, have day-to-day risk management responsibilities. Each of these executives attends the meetings of our Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, at each regular meeting of the Board, management provides a report of the Partnership's financial and operational performance, which often prompts questions or feedback from the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Partnership's internal auditor, who reports directly to the Audit Committee, and reviews the Partnership's contingencies with management and our independent auditors.

Corporate Governance

The Board of Directors has adopted both a Code of Business Conduct and Ethics applicable to our directors, officers and employees, and Corporate Governance Guidelines for directors and the Board. Current copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and charters of the Audit and Compensation Committees of our Board of Directors are available on our website at www.energytransfer.com and will be provided in print form to any Unitholder requesting such information.

Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found and/or provided at such Internet addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Annual Certification

In 2017, our CEO provided to the NYSE the annual CEO certification regarding our compliance with the NYSE corporate governance listing standards.

Conflicts Committee

Our Partnership Agreement provides that the Board of Directors may, from time to time, appoint members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to the Partnership and its Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to the Partnership. Pursuant to the terms of our partnership agreement, any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Unitholders. These duties are limited by our Partnership Agreement (see "Risks Related to Conflicts of Interest" in "Item 1A. Risk Factors" in this annual report).

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE's standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 407 (d)(5) of Regulation S-K. The Board has determined that based on relevant experience, Audit Committee member David K. Skidmore qualified as Audit Committee financial expert during 2017. A description of the qualifications of Mr. Skidmore may be found elsewhere in this Item under "Directors and Executive Officers of our General Partner."

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, review our procedures for internal auditing and the adequacy of our internal accounting controls, consider the qualifications and independence of our independent accountants, engage and direct our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by auditing standards, and makes recommendations to the Board of Directors relating to our audited financial statements. The Audit Committee periodically recommends to the Board of Directors any changes or modifications to its charter that may be required. The Board of Directors adopts the charter for the Audit Committee. In February 2018, W. Brett Smith was appointed to the Board of Directors and the Audit Committee to replace Mr. Collins. Messrs. Grimm and Skidmore also serve on the Audit Committee. Mr. Collins served on the Audit Committee until he passed away on January 28, 2018.

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, our Board of Directors has established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers under the equity compensation plans adopted by our Unitholders, including the performance standards or other restrictions pertaining to the vesting of any such awards. Pursuant to the charter of the Compensation Committee, a director serving as a member of the Compensation Committee may not be an officer of or employed by the General Partner, the Partnership or its subsidiaries. Michael K. Grimm and David K. Skidmore serve as the members of the Compensation Committee and Mr. Grimm serves as the chairman of the Compensation Committee. Our Board of Directors has determined that both Messrs. Grimm and Skidmore are "independent" (as that term is defined in the applicable NYSE corporate governance standards).

The Compensation Committee's responsibilities include, among other duties, the following:

- annually review and approve goals and objectives relevant to compensation of the CEO, if applicable;

- annually evaluate the CEO's performance in light of these goals and objectives, and make recommendations to the Board of Directors with respect to the CEO's compensation levels, if applicable, based on this evaluation;
- based on input from, and discussion with, the CEO, make recommendations to the Board of Directors with respect to non-CEO executive officer compensation, including incentive compensation and compensation under equity- based plans;
- make determinations with respect to the grant of equity-based awards to executive officers under our equity incentive plans;
- periodically evaluate the terms and administration of ETP's short-term and long-term incentive plans to assure that they are structured and administered in a manner consistent with ETP's goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments, if appropriate;
- periodically evaluate the compensation of the directors;
- retain and terminate any compensation consultant to be used to assist in the evaluation of director, CEO or executive officer compensation; and
- perform other duties as deemed appropriate by the Board of Directors.

Matters relating to the nomination of directors or corporate governance matters are addressed to and determined by the full Board of Directors.

Code of Business Conduct and Ethics

The Board of Directors has adopted a Code of Business Conduct and Ethics applicable to our officers, directors and employees. Specific provisions are applicable to the principal executive officer, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our General Partner. Amendments to, or waivers from, the Code of Business Conduct and Ethics will be available on our website and reported as may be required under SEC rules. Any technical, administrative or other non-substantive amendments to the Code of Business Conduct and Ethics may not be posted.

Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. The Chairman of each of our Audit and Compensation Committee alternate as the presiding director of such meetings.

We have established a procedure by which Unitholders or interested parties may communicate directly with the Board of Directors, any committee of the Board, any independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person or entity to the attention of our General Counsel at Energy Transfer Partners, L.P., 8111 Westchester Drive, Suite 600, Dallas, Texas 75225 or generalcounsel@energytransfer.com. Communications are distributed to the Board of Directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

Directors and Executive Officers of Our General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our General Partner as of February 23, 2018. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	62	Chief Executive Officer and Chairman of the Board of Directors
Matthew S. Ramsey	62	Director, President and Chief Operating Officer
Thomas E. Long	61	Chief Financial Officer
Marshall S. (Mackie) McCrea, III	58	Director and ETE Group Chief Operating Officer and Chief Commercial Officer
James M. Wright, Jr.	49	General Counsel
A. Troy Sturrock	47	Senior Vice President, Controller and Principal Accounting Officer
Ray C. Davis	76	Director
Michael K. Grimm	63	Director
David K. Skidmore	62	Director
W. Brett Smith	58	Director

Messrs. Warren, McCrea and Ramsey also serve as directors of ETE's general partner.

Mr. Ted Collins, Jr. served as a director until he passed away on January 28, 2018. Messrs. Davis and Smith were appointed to the Board of Directors in February, 2018.

Set forth below is biographical information regarding the foregoing officers and directors of our General Partner:

Kelcy L. Warren. Mr. Warren is the Chief Executive Officer and Chairman of the Board of Directors of the general partner of ETP. Mr. Warren also serves as Chairman of the Board of Directors of the general partner of Energy Transfer Equity, L. P. Mr. Warren also served as the Chief Executive Officer of PennTex Midstream Partners, LP's general partner from November 2016 to July 2017. Prior to the combination of the operations of ETP and Heritage Propane in 2004, Mr. Warren co-founded the entities that acquired and operated the midstream assets that were contributed in the merger. From 1996 to 2000, Mr. Warren served as a Director of Crosstex Energy, Inc. and from 1993 to 1996, he served as President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 30 years of business experience in the energy industry. The member of our general partner selected Mr. Warren to serve as a director and as Chairman because he is the Partnership's Chief Executive Officer and has more than 30 years in the natural gas industry. Mr. Warren also has relationships with chief executives and other senior management at natural gas transportation companies throughout the United States, and brings a unique and valuable perspective to the Board of Directors.

Matthew S. Ramsey. Mr. Ramsey was appointed as a director of ETE's general partner in July 2012 and as a director of ETP's general partner in November 2015. Mr. Ramsey was named President and Chief Operating Officer of ETP's general partner in November 2015. Mr. Ramsey is also a director of Sunoco LP, serving as chairman of Sunoco LP's board since April 2015. Mr. Ramsey also served as President and Chief Operating Officer and Chairman of the board of directors of PennTex Midstream Partners, LP's general partner, from November 2016 to July 2017. Mr. Ramsey previously served as President of RPM Exploration, Ltd., a private oil and gas exploration partnership generating and drilling 3-D seismic prospects on the Gulf Coast of Texas. Mr. Ramsey is currently a director of RSP Permian, Inc. (NYSE: RSPP), where he serves as chairman of the compensation committee and as a member of the audit committee. Mr. Ramsey formerly served as President of DDD Energy, Inc. until its sale in 2002. From 1996 to 2000, Mr. Ramsey served as President and Chief Executive Officer of OEC Compression Corporation, Inc., a publicly traded oil field service company, providing gas compression services to a variety of energy clients. Previously, Mr. Ramsey served as Vice President of Nuevo Energy Company, an independent energy company. Additionally, he was employed by Torch Energy Advisors, Inc., a company providing management and operations services to energy companies including Nuevo Energy, last serving as Executive Vice President. Mr. Ramsey joined Torch Energy as Vice President of Land and was named Senior Vice President of Land in 1992. Mr. Ramsey holds a B.B.A. in Marketing from the University of Texas at Austin and a J.D. from South Texas College of Law. Mr. Ramsey is a graduate of Harvard Business School Advanced Management Program. Mr. Ramsey is licensed to practice law in the State of Texas. He is qualified to practice in the Western District of Texas and the United States Court of Appeals for the Fifth Circuit. Mr. Ramsey formerly served as a director of Southern Union Company. The member of our General Partner recognize Mr. Ramsey's vast experience in the oil and gas space and believe that he provides valuable industry insight as a member of our Board of Directors.

Thomas E. Long. Mr. Long is the Group Chief Financial Officer of ETE since February 2016. Mr. Long also served as the Chief Financial Officer and as a director of PennTex Midstream Partners, LP's general partner, from November 2016 to July 2017. Mr. Long has served as a director of Sunoco LP since May 2016. Mr. Long previously served as Chief Financial Officer of our General Partner since April 2015 and as Executive Vice President and Chief Financial Officer of Regency GP LLC from November 2010 to April 2015. From May 2008 to November 2010, Mr. Long served as Vice President and Chief Financial Officer of Matrix Service Company. Prior to joining Matrix, he served as Vice President and Chief Financial Officer of DCP Midstream Partners, LP, a publicly traded natural gas and natural gas liquids midstream business company located in Denver, CO. In that position, he was responsible for all financial aspects of the company since its formation in December 2005. From 1998 to 2005, Mr. Long served in several executive positions with subsidiaries of Duke Energy Corp., one of the nation's largest electric power companies.

Marshall S. (Mackie) McCrea, III. Mr. McCrea is the Group Chief Operating Officer and Chief Commercial Officer for the Energy Transfer family and has served in that capacity since November 2015. Mr. McCrea was appointed as a director of the general partner of ETP in December 2009. Prior to that, he served as President and Chief Operating Officer of ETP's general partner from June 2008 to November 2015 and President – Midstream from March 2007 to June 2008. Previously he served as the Senior Vice President – Commercial Development since January 2004. In March 2005, Mr. McCrea was named President of La Grange Acquisition LP, ETP's primary operating subsidiary, after serving as Senior Vice President-Business Development and Producer Services since 1997. Mr. McCrea also currently serves on the Board of Directors of the general partner of ETE. Mr. McCrea also served as the Chairman of the Board of Directors of the general partner of Sunoco Logistics from October 2012 to April 2017. The member of our general partner selected Mr. McCrea to serve as a director because he brings extensive project development and operational experience to the Board. He has held various positions in the natural gas business over the past 25 years and is able to assist the Board of Directors in creating and executing the Partnership's strategic plan.

James M. Wright, Jr. Jim Wright was elected General Counsel of our General Partner in December 2015. Mr. Wright has been a part of the Energy Transfer legal team with increasing levels of responsibility since July 2005, and served as its Deputy General Counsel since May 2008. Prior to joining Energy Transfer, Mr. Wright gained significant experience at Enterprise Products Partners, L.P., El Paso Corp., Sonat Exploration Company and KPMG Peat Marwick LLP. Mr. Wright earned a Bachelor of Business Administration degree in Accounting and Finance from Texas A&M University and a JD from South Texas College of Law.

A. Troy Sturrock. Mr. Sturrock has served as the Senior Vice President and Controller of the general partner of ETP since August 2016 and previously served as Vice President and Controller of our General Partner since June 2015. Mr. Sturrock also served as a Senior Vice President of PennTex Midstream Partners, LP's general partner, from November 2016 until July 2017, and as its Controller and Principal Accounting Officer from January 2017 until July 2017. Mr. Sturrock previously served as Vice President and Controller of Regency GP LLC from February 2008, and in November 2010 was appointed as the principal accounting officer. From June 2006 to February 2008, Mr. Sturrock served as the Assistant Controller and Director of financial reporting and tax for Regency GP LLC. Mr. Sturrock is a Certified Public Accountant.

Ray C. Davis. Mr. Davis was appointed to the Board of Directors of our general partner in February 2018. From February 2013 until February 2018, Mr. Davis was an independent investor. He has also been a principal owner, and served as co-chairman of the board of directors, of the Texas Rangers major league baseball club since August 2010. Mr. Davis previously served on the Board of Directors of the general partner of ETE, effective upon the closing of ETE's initial public offering in February 2006 until his resignation in February 2013. Mr. Davis also served as ETP's Co-Chief Executive Officer from the combination of the midstream and transportation operations of ETC OLP and the retail propane operations in January 2004 until his retirement from these positions in August 2007, and as Co-Chairman of the Board of Directors of our general partner from January 2004 until June 2011. Mr. Davis also held various executive positions with Energy Transfer prior to 2004. From 1996 to 2000, he served as a Director of Crosstex Energy, Inc. From 1993 to 1996, he served as Chairman of the Board of Directors and Chief Executive Officer of Cornerstone Natural Gas, Inc. The member of our general partner selected Mr. Davis to serve as a director based on his over 40 years of business experience in the energy industry and his expertise in the Partnership's asset portfolio.

Michael K. Grimm. Mr. Grimm is one of the original founders of Rising Star Energy, L.L.C., a privately held upstream exploration and production company active in onshore continental United States, and served as its President and Chief Executive Officer from 1995 until 2006 when it was sold. Mr. Grimm is President of Rising Star Petroleum, LLC and is Chairman of the Board of RSP Permian, Inc. (NYSE: RSPP), which is active in the drilling and developing of West Texas Permian Basin oil reserves. Prior to the formation of Rising Star, Mr. Grimm was Vice President of Worldwide Exploration and Land for Placid Oil Company from 1990 to 1994. Prior to joining Placid Oil Company, Mr. Grimm was employed by Amoco Production Company for thirteen years where he held numerous positions throughout the exploration department in Houston, New Orleans and Chicago. Mr. Grimm has been an active member of the Independent Petroleum Association of America, the American Association of Professional Landmen, Dallas Producers Club, Houston Producers Forum, and Fort Worth Wildcatters. Mr. Grimm has served as a Director of our General Partner since December 2005 and is the Chairman of the Audit Committee and of the Compensation Committee. He has a B.B.A. from the University of Texas at Austin. The member of our general partner selected Mr. Grimm to serve as a director because of his extensive experience in the energy industry and his service as a senior executive at several energy-related companies, in addition to his contacts in the industry gained through his involvement in energy-related organizations.

David K. Skidmore. Mr. Skidmore has served as Vice President of Ventex Oil & Gas, Inc. since 1995 and has been actively involved in exploration and production throughout the Gulf Coast and mid-Continent regions for over 35 years. He founded Skidmore Exploration, Inc. in 1981 and has been an independent oil and gas producer since that time. From 1977 to 1981, he worked for Paraffine Oil Corporation and Texas Oil & Gas in Houston. He holds BS degrees in both Geology and Petroleum Engineering, is a Certified Petroleum Geologist and Registered Professional Engineer, and active member of the AAPG, and SPE. Mr. Skidmore was appointed to the Board of Directors of our general partner in March 2013. Mr. Skidmore is a member of both the Audit Committee and Compensation Committee. The member of our general partner selected Mr. Skidmore to serve as a director because of his continual involvement in geological, geophysical, legal, engineering and accounting aspects of an active oil and gas exploration and production company. As an energy professional, active oil and gas producer and successful business owner, Mr. Skidmore possesses valuable first-hand knowledge of the energy transportation business and market conditions affecting its economics.

W. Brett Smith. Mr. Smith was appointed to the Board of Directors of our general partner in February 2018 and has served on the audit committee since that time. He has served as President and Managing Partner of Rubicon Oil & Gas, LLC since October 2000. He has also served as President of Rubicon Oil & Gas II, LP since May 2005, President of Quientesa Royalty LP since February 2005 and President of Action Energy LP since October 2008. Mr. Smith was President of Rubicon Oil & Gas, LP from October 2000 to May 2005. Previously, he served as Vice President with Collins & Ware, Inc. from 1998 to September 2000 and was responsible for land and exploration since the firm's inception. For more than 30 years Mr. Smith has been active in assembling exploration prospects in the Permian Basin, Oklahoma, New Mexico and the Rocky Mountain areas. Mr. Smith received a Bachelor of Science Degree from the University of Texas. Mr. Smith serves on the board of directors of Sunoco LP and is a member of its

audit and compensation committees. Mr. Smith was selected to serve on our Board based on his extensive experience in the energy industry, including his past experiences as an executive with various energy companies.

Compensation of the General Partner

Our General Partner does not receive any management fee or other compensation in connection with its management of the Partnership and the Operating Companies. Our General Partner and its affiliates performing services for the Partnership and the Operating Companies are reimbursed at cost for all expenses incurred on behalf of the Partnership, including the costs of employee compensation allocable to, but not paid directly by, the Partnership, if any, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Our employees are employed by our Operating Companies, and thus, our General Partner does not incur additional reimbursable costs.

Our General Partner is ultimately controlled by the general partner of ETE, which general partner entity is partially-owned by certain of our current and prior named executive officers. We pay quarterly distributions to our General Partner in accordance with our Partnership Agreement with respect to its ownership of a general partner interest and the incentive distribution rights specified in our Partnership Agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our Partnership Agreement, which agreement specifies the amount of cash we distribute to our General Partner based on the amount of cash that we distribute to our limited partners each quarter. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner's executive officers. Our General Partner's distribution rights are described in detail in Note 8 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires the directors and executive officers of our general partner, as well as persons who own more than ten percent of the common units representing limited partnership interests in us, to file reports of ownership and changes of ownership on Forms 3, 4 and 5 with the SEC. The SEC regulations also require that copies of these Section 16(a) reports be furnished to us by such reporting persons. Based upon a review of copies of these reports, we believe all applicable Section 16(a) reports were timely filed in 2017. Certain amendments to these Section 16(a) reports were filed as set forth below:

- On June 26, 2017, an amendment to the original Form 3 for Mr. Warren on May 5, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units indirectly owned by Mr. Warren;
- On June 26, 2017, an amendment to the Form 4 filed for Mr. Warren on May 2, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units indirectly owned by Mr. Warren;
- On May 12, 2017, an amendment to the original Form 3 for Mr. Ramsey on May 5, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units beneficially owned by Mr. Ramsey;
- On May 12, 2017, an amendment to the Form 4 filed for Mr. Ramsey on May 2, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units beneficially owned by Mr. Ramsey;
- On May 19, 2017, an amendment to the original Form 3 filed for Mr. Grimm on May 5, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units beneficially owned by Mr. Grimm;
- On May 19, 2017, an amendment to the Form 4 filed for Mr. Grimm on May 2, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units and ETP restricted units acquired and beneficially owned by Mr. Grimm;
- On May 12, 2017, an amendment to the original Form 3 filed for Mr. Sturrock on May 5, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units beneficially owned by Mr. Sturrock;
- On May 12, 2017, an amendment to the Form 4 filed for Mr. Sturrock on May 2, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units and ETP restricted units beneficially owned by Mr. Sturrock;
- On May 12, 2017, an amendment to the original Form 3 filed for Mr. Wright on May 5, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units beneficially owned by Mr. Wright; and
- On May 12, 2017, an amendment to the Form 4 filed for Mr. Wright on May 2, 2017 was filed to correct an inadvertent clerical error in the number of ETP common units beneficially owned by Mr. Wright.

ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner, which in turn is managed by its general partner, ETP LLC, which we refer to in this Item as "our General Partner." As of December 31, 2017, ETE owned 100% of our General Partner, approximately 27.5 million of our outstanding Common Units and 100% of our outstanding Class H and Class I Units. All of our employees are employed by and receive employee benefits from our Operating Companies.

Effective April 28, 2017, ETP GP replaced SXL GP as the general partner of the former Sunoco Logistics Partners, L.P. (now renamed Energy Transfer Partners, L.P.).

Compensation Discussion and Analysis

Named Executive Officers

The executive officers referred to in this discussion as the "named executive officers" are the following officers with the roles they held for 2017:

- Kelcy L. Warren, Chairman and Chief Executive Officer;
- Thomas E. Long, Chief Financial Officer and Group Chief Financial Officer of ETE's general partner;
- Marshall S. (Mackie) McCrea, III, Group Chief Operating Officer and Chief Commercial Officer
- Matthew S. Ramsey, President and Chief Operating Officer;
- James M. Wright, General Counsel and Assistant Secretary;
- Michael J. Hennigan, Former President and Chief Executive Officer of Sunoco Partners LLC; and
- Peter J. Gvazdauskas, Former Chief Financial Officer and Treasurer of Sunoco Partners LLC.

During 2017, Mr. McCrea, Group Chief Operating Officer and Chief Commercial Officer of ETE's general partner and Mr. Long, as Group Chief Financial Officer of ETE's general partner provided services to each of ETE, ETP (formerly named "Sunoco Logistics Partners L.P."), Energy Transfer, LP (formerly named "Energy Transfer Partners, L.P.") and, in the case of Mr. Long, Sunoco LP. Decisions with respect to Messrs. McCrea's and Long's compensation during 2017 were made by the ETE Compensation Committee in consultation, as appropriate, with the ETP Compensation Committee or the Energy Transfer, LP Compensation Committee as applicable prior to the Sunoco Logistics Merger.

Prior to the Sunoco Logistics Merger in April 2017, Mr. Hennigan's and Mr. Gvazdauskas' primary business responsibilities related to Sunoco Logistics and its consolidated subsidiaries. Prior to the Sunoco Logistics Merger, the compensation committee of Sunoco Partners LLC set the components of Mr. Hennigan's and Mr. Gvazdauskas' compensation, including salary, long-term incentive awards and annual bonus utilizing the same philosophy and methodology adopted by our General Partner.

Our General Partner's Philosophy for Compensation of Executives

In general, our General Partner's executive compensation philosophy is based on the premise that a significant portion of each executive's compensation should be incentive-based or "at-risk" compensation and that executives' total compensation levels should be highly competitive in the marketplace for executive talent and abilities. ETP LLC seeks a total compensation program for the named executive officers that provides for a slightly below the median market annual base compensation rate (i.e. approximately the 40th percentile of market) but incentive-based compensation composed of a combination of compensation vehicles to reward both short and long-term performance that are both targeted to pay-out at approximately the top-quartile of market. ETP LLC believes the incentive-based balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of ETP's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of the named executive officers to the success of ETP and the achievement of the annual financial performance objectives and (ii) the annual grant of time-based restricted unit or phantom unit awards under the equity incentive plan(s), which awards are intended to provide a longer term incentive and retention value to the key employees to focus their efforts on increasing the market price of the publicly traded units and to increase the cash distribution paid to unitholders.

ETP LLC grants restricted unit awards that vest, based generally upon continued employment, at a rate of 60% after the third anniversary of the award and the remaining 40% after the fifth anniversary of the award. ETP LLC believes that these equity-based incentive arrangements are important in attracting and retaining executives, including the named executive officers, and key employees as well as motivating these individuals to achieve business objectives. The equity-based compensation also reflects the importance of aligning the interests of the executives, including the named executive officers, with those of ETP's unitholders.

While ETP is responsible for the direct payment of the compensation of the named executive officers as employees of ETP LLC, ETP or its controlled affiliates, ETP does not participate or have any input in any decisions as to the compensation policies of ETP LLC or the compensation levels of the executive officers of ETP LLC. The compensation committee of the board of directors of ETP LLC (the "ETP Compensation Committee") is responsible for the approval of the compensation policies and the compensation levels of these executive officers. ETP directly pays these executive officers in lieu of receiving an allocation of overhead related to executive compensation from ETP LLC. For a more detailed description of the compensation of the named executive officers, please see "Compensation Tables" below. Both the ETE Compensation Committee and the compensation committee of Sunoco Partners LLC (the "Sunoco Logistics Compensation Committee") follow a substantially similar executive compensation philosophy for executives as the ETP Compensation Committee.

Compensation Philosophy

Our compensation program is structured to achieve the following:

- reward executives with an industry-competitive total compensation package of targeted base salaries and significant incentive opportunities yielding a total compensation package approaching the top-quartile of the market;
- attract, retain and reward talented executive officers and key management employees by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size and in similar lines of business;
- motivate executive officers and key employees to achieve strong financial and operational performance;
- emphasize performance-based or "at-risk" compensation; and
- reward individual performance.

Components of Executive Compensation

For the year ended December 31, 2017, the compensation paid to our named executive officers, other than our Chief Executive Officer, consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- time-vested restricted unit or phantom awards under the equity incentive plan(s);
- payment of distribution equivalent rights ("DERs") on unvested time-based restricted unit or phantom unit awards under the equity incentive plan(s);
- vesting of previously issued time-based restricted unit/phantom unit awards issued pursuant to the ETP equity incentive plan(s) or the equity incentive plan(s) of its affiliates;
- 401(k) plan employer contributions; and
- severance payments where applicable.

Mr. Warren, our Chief Executive Officer, has voluntarily elected not to accept any salary, bonus or equity incentive compensation (other than a salary of $1.00 per year plus an amount sufficient to cover his allocated employee premium contributions for health and welfare benefits).

Methodology

The ETP Compensation Committee considers relevant data available to it to assess our competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for executive officers, including the named executive officers. The ETP Compensation Committee also considers individual performance, levels of responsibility, skills and experience.

Periodically, the compensation committee of the general partner of ETE (the "ETE Compensation Committee") or the ETP Compensation Committee engages a third-party consultant to provide market information for compensation levels at peer companies in order to assist in the determination of compensation levels for the executives, including the named executive officers. Most recently, Longnecker & Associates ("Longnecker") evaluated the market competitiveness of total compensation levels of a number of executives of ETE, ETP and Sunoco Logistics to provide market information with respect to compensation of those executives during the year ended December 31, 2017. In particular, the 2017 review by Longnecker was designed to (i) evaluate the market competitiveness of total compensation levels for certain members of senior management, including the named executive officers; (ii) assist in the determination of appropriate compensation levels for senior management, including the named executive

officers; and (iii) confirm that the compensation programs were yielding compensation packages consistent with the overall compensation philosophy.

In conducting its review, Longnecker specifically considered the larger size of the combined ETE and ETP entities from an energy industry perspective. During 2017, Longnecker assisted in the development of the final "peer group" of leading companies in the energy industry that most closely reflect ETP's profile in terms of revenues, assets and market value as well as competition for talent at the senior management level and similarly situated general industry companies with similar revenues, assets and market value. In setting such peer group, both ETP and Longnecker considered the size of ETE and ETP on a combined basis. Unlike in prior evaluations conducted by Longnecker, a determination was made to focus the analysis specifically on the energy industry based on a determination that an energy industry peer group provided a more than sufficient amount of comparative data to consider and evaluate total compensation. This decision allowed Longnecker to report on specific industry related data comparing the levels of annual base salary, annual short-term cash bonus and long-term equity incentive awards at industry peer group companies with those of the named executive officers to ensure that compensation of the named executive officers is both consistent with the compensation philosophy and competitive with the compensation for executive officers of these other companies. The identified companies were:

Energy Peer Group:

• Conoco Phillips	• Anadarko Petroleum Corporation
• Enterprise Products Partners, L.P.	• Marathon Petroleum Corporation
• Plains All American Pipeline, L.P.	• Kinder Morgan, Inc.
• Halliburton Company	• The Williams Companies, Inc.
• Valero Energy Corporation	• Phillips 66

The compensation analysis provided by Longnecker in 2017 covered all major components of total compensation, including annual base salary, annual short-term cash bonus and long-term incentive awards for the senior executives of these companies. In preparing the review materials, Longnecker utilized generally accepted compensation principles as determined by WorldatWork and gathered data from the public peer companies and published salary surveys.

Following Longnecker's 2017 review, both the ETE Compensation Committee and the ETP Compensation Committee reviewed the information provided, including Longnecker's specific conclusions and recommended considerations for all compensation going forward. The ETE Compensation Committee and ETP Compensation Committee considered and reviewed the results of the study performed by Longnecker to determine if the results indicated that the compensation programs were yielding a competitive total compensation model prioritizing incentive-based compensation and rewarding achievement of short and long-term performance objectives and considered Longnecker's conclusions and recommendations. While Longnecker found that ETP is achieving its stated objectives with respect to the "at-risk" approach, they also found that certain adjustments should be implemented to allow ETP to achieve its targeted percentiles on base compensation and incentive compensation (short and long-term) as described below.

With the pending Sunoco Logistics Merger, the Sunoco Logistics Compensation Committee's only compensation actions during 2017 prior to closing related to 2016 bonus awards and are not reported on in this report on executive compensation.

Base Salary. Base salary is designed to provide for a competitive fixed level of pay that attracts and retains executive officers, and compensates them for their level of responsibility and sustained individual performance (including experience, scope of responsibility and results achieved). The salaries of the named executive officers are reviewed on an annual basis. As discussed above, the base salaries of the named executive officers are targeted to yield an annual base salary slightly below the median level of market (i.e. approximately the 40th percentile of market) and are determined by the ETP Compensation Committee after taking into account the recommendations of Mr. Warren. During the 2017 merit review process, the ETP Compensation Committee considered the recommendations of Mr. Warren, the results of the Longnecker study and the merit increase pool set for all employees of ETP LLC, ETP and Sunoco Logistics.

The ETP Compensation Committee approved an increase to Mr. Ramsey's base salary of 2.5% to $653,438 from its prior level of $637,500, Mr. Wrights base salary was initially increased 2.5% to $392,063 at the time of merit increases, but was subsequently increased to $415,000 based largely upon the results of the Longnecker study. The CEO (who has voluntarily elected to forgo nearly all base compensation) did not receive any base salary adjustment during 2017.

In the case of Mr. McCrea, the ETE Compensation Committee approved an increase of 2.5% to Mr. McCrea's base salary to $1,045,500 from its prior level of $1,020,000.

In the case of Mr. Long, the ETE Compensation Committee approved an increase to Mr. Long's base salary to $530,000 from its prior level of $459,000, which represents an approximately 15.5% increase and was based largely on the recommendation of Mr. Warren and the results of the Longnecker study.

Messrs. Hennigan and Gvazdauskas did not receive a base salary adjustment during 2017, as Mr. Hennigan had left ETP prior to merit increases and Mr. Gvazdauskas had been determined to be a transition employee remaining with ETP only for a short period of time.

The 2.5% increase to Mr. Ramsey and the initial 2.5% increase to Mr. Wright reflected a base salary increase consistent with the 2.5% annual merit increase pool established for all employees of the ETP LLC, ETP, Sunoco Logistics and their affiliates for 2017 by the ETP Compensation Committee.

Annual Bonus. In addition to base salary, the ETE Compensation Committee and the ETP Compensation Committee make determinations whether to make discretionary annual cash bonus awards to executives, including the named executive officers, other than the CEO (who has voluntarily elected to forgo any annual bonuses), following the end of the year under the Energy Transfer Partners, L.L.C. Annual Bonus Plan (the "Bonus Plan"). The ETE Compensation Committee will consider a 2017 annual cash bonus for Messrs. McCrea and Long and the ETP Compensation Committee will consider 2017 annual cash bonus awards for Messrs. Ramsey and Wright.

These discretionary bonuses, if awarded, are intended to reward the named executive officers for the achievement of financial performance objectives during the year for which the bonuses are awarded in light of the contribution of each individual to profitability and success during such year. The ETE Compensation Committee and the ETP Compensation Committee also consider the recommendation of the CEO in determining the specific annual cash bonus amounts for each of the other named executive officers. The ETE Compensation Committee and the ETP Compensation Committee do not establish their own financial performance objectives in advance for purposes of determining whether to approve any annual bonuses, and do not utilize any formulaic approach to determine annual bonuses.

For 2017, annual bonuses to be awarded to Messrs. McCrea, Ramsey, Long, McCrea and Wright will be determined under the Bonus Plan. The ETE Compensation Committee's and the ETP Compensation Committee's evaluation of performance and determination of an overall available bonus pool is based on an internal earnings target generally based on targeted EBITDA (the "Earnings Target") budget and the performance of each department compared to the applicable departmental budget (with such performance measured based on the specific dollar amount of general and administrative expenses set for each department). The two performance criteria are weighted 75% on the internal Earnings Target budget criteria and 25% on internal department financial budget criteria. Internal Earnings Target is the primary performance factor in determining annual bonuses, while internal department financial budget criteria is considered to ensure that general and administrative costs are being effectively managed in a prudent manner.

The internal financial budgets are generally developed for each business segment, and then aggregated with appropriate corporate level adjustments, to reflect an overall performance objective that is reasonable in light of market conditions and opportunities based on a high level of effort and dedication across all segments of the business. The evaluation of performance versus the internal financial budget is based on EBITDA for a calendar year.

In general, both the ETE Compensation Committee and the ETP Compensation Committee believe that performance at or above the internal Earnings Target and at or below internal department financial budgets would support bonus pools to the named executive officers ranging from 105% to 160% of their annual base earnings (which amount reflects the actual base salary earned during the calendar year to reflect periods before and after any base salary adjustments), with the ability to fund up to an additional 20% above each named executive officer's target bonus pool upon achievement of 110% of the internal Earnings Target and 110% of the internal department financial budgets. For 2017, the short-term annual cash bonus pool targets for each of the named executive officers were as follows: for Mr. McCrea, 160% of his annual base earnings; for Mr. Ramsey, 130% of his annual base earnings, which represented an adjustment from his previous target of 140%; for Mr. Long, 130% of his annual base earnings; and for Mr. Wright, 115% of his annual base earnings, which represents an increase from his previous target of 105%. The adjustment to Mr. Ramsey's base target represented a desire on the part of the Chairman and CEO to align the senior officers that report to him, other than Mr. McCrea, with a consistent bonus target. The increase for Mr. Wright was based on recognition of his role as General Counsel of ETP and the results of the Longnecker study.

In February 2018, the ETP Compensation Committee certified 2017 performance results under the Bonus Plan, which resulted in a bonus payout of 100% of target, which reflected achievement of 101.6% of the internal Earnings Target and 100% of the budget criteria. Based on the approved results, the ETP Compensation Committee approved a cash bonus relating to the 2017 calendar year to Messrs. Ramsey and Wright in the amounts of $835,125 and $453,067, respectively.

The ETE Compensation Committee approved a cash bonus relating to the 2017 calendar year to Messrs. McCrea and Long in the amounts of $1,644,554 and $625,100, respectively.

In the case of Mr. Hennigan, he received no bonus award in respect of 2017 as he had left ETP prior to consideration of bonus awards. Mr. Gvazdauskas will receive a cash bonus of $336,000, which amount reflects a target payout at his bonus pool target of 105%. The bonus paid to Mr. Gvazdauskas was approved outside of the process of the named executive officers as he no longer serves as a named executive officers, but was considered consistent with the process used to evaluate bonus awards to other executives of ETP.

Equity Awards. In 2017, ETE'S Board of Directors adopted the Amended and Restated Energy Transfer Equity, L.P. Long-Term Incentive Plan (the "ETE Plan"). The ETE Plan authorizes the ETE Compensation Committee, in its discretion, to grant awards of restricted units, phantom units, unit options, unit appreciation rights and other awards related to ETE common units upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by the ETE Plan. The ETE Plan has not been approved by a majority of ETE unitholders.

ETP currently has three incentive plans: (i) the Second Amended and Restated Energy Transfer Partners, L.P. 2008 Incentive Plan (the "2008 Incentive Plan"); (ii) the Energy Transfer Partners, L.P. Amended and Restated 2011 Long-Term Incentive Plan (the "2011 Incentive Plan") and the (iii) Energy Transfer Partners, L.L.C. Long-Term Incentive Plan, as amended and restated (the "ETP Plan"). Each of the 2008 Incentive Plan, 2011 Incentive Plan and the ETP Plan authorizes the ETP Compensation Committee, in its discretion, to grant awards of restricted units, phantom units, unit options and other awards related to ETP common units upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by each such plan. The ETP Compensation Committee determined and/or approved the terms of the unit grants awarded to the named executive officers, including the number of common units subject to the restricted unit award and the vesting structure of those restricted unit awards. All of the awards granted to the named executive officers under these equity incentive plans have consisted of restricted unit awards that are subject to vesting over a specified time period. Upon vesting of any restricted unit award, ETP common units are issued.

Prior to the Sunoco Logistics Merger, Messrs. Hennigan and Gvazdauskas participated in the Sunoco Partners LLC Long-Term Incentive Plan, as amended, (the "Sunoco Logistics Plan"), which became the ETP Plan after the Sunoco Logistics Merger.

For 2017, the annual long-term incentive targets for the named executive officers were 900% of annual base salary for Mr. McCrea, 600% of annual base salary for Mr. Ramsey, 500% of annual base salary for Mr. Long, 300% of annual base salary for Mr. Wright which represented an increase from his prior target of 250%. Messrs. Hennigan and Gvazdauskas did not receive long-term incentive awards in 2017. The ETP Compensation Committee approved the increase to Mr. Wright's long-term incentive target in recognition of his work as General Counsel of ETP and the results of the Longnecker study. In approving long-term incentive awards for Mr. Long, the ETP Compensation Committee and the compensation committee of Sunoco LP's general partner utilized the targets set by the ETE Compensation Committee.

In December 2017, the ETE Compensation Committee in consultation with ETE's Chairman determined to issue long-term incentive awards under the ETE Plan to the ETE named executive officers, including Messrs. McCrea and Long and Mr. Ramsey. This determination was made in consideration of limiting the number of units issued under the ETP unit plans for 2017. In December of 2017, the ETE Compensation Committee approved grants of phantom unit awards to Messrs. McCrea, Ramsey and Long of 537,379 units, 223,908 units and 121,074 units, respectively. Messrs. McCrea's and Ramsey's 2017 long-term incentive awards were allocated entirely to the ETE Plan.

The phantom unit awards provide for vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year, generally subject to continued employment through each specified vesting date. The phantom unit awards entitle the recipients of the phantom unit awards to receive, with respect to each ETE unit subject to such award that has not either vested or been forfeited, a DER cash payment promptly following each such distribution by ETE to its unitholders. In approving the grant of such restricted unit awards, the ETE Compensation Committee considered several factors, including the long-term objective of retaining such individuals as key drivers of ETE's and ETP's future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity awards subject to vesting. Vesting of the 2017 awards would accelerate in the event of the death or disability of the named executive officer or in the event of a change in control of ETE as that term is defined under the ETE Plan.

Upon vesting of the phantom units awarded under the ETE Plan, the ETE Compensation Committee reserves the right to determine if, upon vesting, such Phantom units shall be settled in (i) common units of ETE (subject to the approval of the ETE Plan prior to the first vesting date by a majority of ETE's unitholders pursuant to the rules of the New York Stock Exchange); (ii) cash equal to the Fair Market Value (as such term is defined in the ETE Plan) of the ETE common units that would otherwise be delivered pursuant to the terms of each named executive officers grant agreement; or (iii) other securities or property (including, without limitation, delivery of common units of ETP purchased by ETE in the open market) in an amount equal to the Fair Market Value

of ETE common units that would otherwise be delivered pursuant to the terms of the grant agreement, or a combination thereof as determined by the ETE Compensation Committee in its discretion

Additionally, with respect to Mr. Long, in 2017, in discussions between the ETE Compensation Committee and the compensation committees of the general partner of Sunoco LP, it was determined that a portion of Mr. Long's total long-term incentive award target value would be composed of phantom units awarded under the ETE Plan as well as restricted phantom units under the Sunoco LP equity plan in consideration for his role and responsibilities at those partnerships. Mr. Long's total 2017 long-term awards were allocated 80% to the ETE Plan and 20% to the Sunoco LP equity plan. Mr. Long serves as a financial advisor in matters related to mergers and acquisitions and financing activities to Sunoco LP, and certain personnel responsible for the accounting and financial reporting functions provided to Sunoco LP report into his organization.

In connection with his role at Sunoco LP, in December 2017, the compensation committee of Sunoco LP's general partner awarded Mr. Long time-based restricted phantom units of Sunoco LP in the amount of 17,097 units. The terms and conditions of the restricted unit/restricted phantom unit awards to Mr. Long under the Sunoco LP equity plan are identical to the terms and conditions of the restricted unit awards under ETP's equity plans and the phantom units awarded under the ETE Plan to other named executive officers.

In December 2017, the ETP Compensation Committee approved grants of restricted unit awards to Mr. Wright of 62,250 units under the 2008 Incentive Plan related to ETP common units.

The restricted unit awards under the 2008 Incentive Plan, the 2011 Incentive Plan and the ETP Plan provide for vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year, generally subject to continued employment through each specified vesting date. The restricted unit awards entitle the recipients of the restricted unit awards to receive, with respect to each ETP common unit subject to such award that has not either vested or been forfeited, a DER cash payment promptly following each such distribution by ETP to its unitholders. In approving the grant of such restricted unit awards, the ETP Compensation Committee considered several factors, including the long-term objective of retaining such individuals as key drivers of ETP's future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity awards subject to vesting. Vesting of the 2014, 2015, 2016 and 2017 awards would accelerate in the event of the death or disability of the named executive officer or in the event of a change in control of ETP as that term is defined under the 2008 Incentive Plan and 2011 Incentive Plan. For awards previously granted under the 2008 Incentive Plan and 2011 Incentive Plan prior to December 2014, unvested awards may also become vested upon a change in control at the discretion of the ETP Compensation Committee. Under the ETP Plan, awards granted in 2014 and 2015 would be accelerated in the event of a change in control of the applicable partnership (other than a change in control of an affiliate).

The restricted phantom unit awards for 2016 and 2017 under the Sunoco LP equity incentive plan generally require the continued employment of the recipient during the vesting period, provided however, the unvested awards will be accelerated in the event of a change in control of the applicable partnership (other than a change in control to an affiliate) or the death or disability of the award recipient prior to the applicable vesting period being satisfied. Under the Sunoco LP equity incentive plan, awards granted in 2014 and 2015 would be accelerated in the event of a change in control of the applicable partnership (other than a change in control of an affiliate).

Messrs. Hennigan and Gvazdauskas did not receive a long-term incentive awards for 2017 as Mr. Hennigan had left ETP prior to merit increases and Mr. Gvazdauskas had been determined to be a transition employee remaining with ETP only for a short period of time.

As discussed below under "Potential Payments Upon a Termination or Change of Control," certain equity awards automatically accelerate upon a change in control event, which means vesting automatically accelerates upon a change in control irrespective of whether the officer is terminated. In addition, the 2015 award to Mr. Ramsey in accordance with the terms of his offer letter and the 2014 award to Mr. Hennigan included a provision in the applicable award agreement for acceleration of unvested restricted unit awards upon a termination of employment without "cause" by the general partner of the applicable partnership issuing the award. For purposes of the awards the term "cause" shall mean: (i) a conviction (treating a nolo contendere plea as a conviction) of a felony (whether or not any right to appeal has been or may be exercised), (ii) willful refusal without proper cause to perform duties (other than any such refusal resulting from incapacity due to physical or mental impairment), (iii) misappropriation, embezzlement or reckless or willful destruction of property of the partnership or any of its affiliates, (iv) knowing breach of any statutory or common law duty of loyalty to the partnership or any of its or their affiliates, (v) improper conduct materially prejudicial to the business of the partnership or any of its or their affiliates, (vi) material breach of the provisions of any agreement regarding confidential information entered into with the partnership or any of its or their affiliates or (vii) the continuing failure or refusal to satisfactorily perform essential duties to the partnership or any of its or their affiliate. Mr. Hennigan's 2014 award became fully vested upon his termination of employment in 2017.

Permitting the accelerated vesting of equity awards upon a change in control creates an important retention tool by enabling employees to realize value from these awards in the event of a change in control transaction.

Unit Ownership Guidelines. In December 2013, the ETP Board adopted the ETP Executive Unit Ownership Guidelines (the "Guidelines"), which set forth minimum ownership guidelines applicable to certain executives of ETP with respect to ETP common units. The applicable unit ownership guidelines are denominated as a multiple of base salary, and the amount of common units required to be owned increases with the level of responsibility. Under these Guidelines, the President and Chief Operating Officer is expected to own common units having a minimum value of five times his base salary, while each of the remaining named executive officers (other than the CEO) are expected to own common units having a minimum value of four times their respective base salary. In addition to the named executive officers, these Guidelines also apply to other covered executives, which executives are expected to own either directly or indirectly in accordance with the terms of the Guidelines, common units having minimum values ranging from two to four times their respective base salary. The Guidelines do not apply to the CEO, who receives a salary of $1.00 per year plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits.

ETP LLC and the ETP Compensation Committee believe that the ownership of the common units, as reflected in the Guidelines, is an important means of tying the financial risks and rewards for the executives to total unitholder return, aligning the interests of such executives with those of ETP's unitholders, and promoting ETP's interest in good corporate governance.

Covered executives are generally required to achieve their ownership level within five years of becoming subject to the Guidelines. Mr. Ramsey will be required to be compliant with the Guidelines in November 2020 and Mr. Wright for his current role in 2021.

Covered executives may satisfy the Guidelines through direct ownership of common units or indirect ownership by certain immediate family members. Direct or indirect ownership of ETE and Sunoco LP common units shall count on a one-to-one ratio for purposes of satisfying minimum ownership requirements; however, unvested unit awards may not be used to satisfy the minimum ownership requirements.

Covered executives who have not yet met their respective guideline must retain and hold all common units (less common units sold to cover the executive's applicable taxes and withholding obligation) received in connection with long-term incentive awards. Once the required ownership level is achieved, ownership of the required common units must be maintained for as long as the covered executive is subject to the Guidelines. However, those individuals who have met or exceeded their applicable ownership guideline may dispose of common units in a manner consistent with applicable laws, rules and regulations, including regulations of the SEC and ETP's internal policies, but only to the extent that such individual's remaining ownership of common units would continue to exceed the applicable ownership guideline.

Qualified Retirement Plan Benefits. The Energy Transfer Partners GP, L.P. 401(k) Plan (the "ETP 401(k) Plan") is a defined contribution 401(k) plan, which covers substantially all of ETP's employees, including the named executive officers. Employees may elect to defer up to 100% of their eligible compensation after applicable taxes, as limited under the Code. Matching contributions are not less than the aggregate amount of matching contributions that would be credited to a participant's account based on a rate of match equal to 100% of each participant's elective deferrals up to 5% of covered compensation. The amounts deferred by the participant are fully vested at all times, and the amounts contributed by ETP become vested based on years of service. This benefit is provided as a means to incentivize employees and provide them with an opportunity to save for their retirement.

ETP provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with a base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

Health and Welfare Benefits. All full-time employees, including the named executive officers, may participate in the health and welfare benefit programs including medical, dental, vision, flexible spending, life insurance and disability insurance.

Termination Benefits. The named executive officers do not have any employment agreements that call for payments of termination or severance benefits or that provide for any payments in the event of a change in control of ETP LLC. The 2008 Incentive Plan and 2011 Incentive Plan provide the ETP Compensation Committee with the discretion, unless otherwise specified in the applicable award agreement, to provide for immediate vesting of all unvested restricted unit awards in the event of (i) a change of control, as defined in the applicable plan; (ii) death or (iii) disability, as defined in the applicable plan. In the case of the December 2014, 2015 and 2016 long-term incentive awards to the named executive officers under the 2008 Incentive Plan or, as applicable, the Sunoco Logistics Plan and the Sunoco LP equity plan, the unvested portion of restricted unit awards would immediately and fully vest in the event of a change of control, as defined in the applicable plan. Please refer to "Compensation Tables - Potential Payments Upon a Termination or Change of Control" for additional information.

In addition, ETP LLC has also adopted the ETP GP Severance Plan and Summary Plan Description effective as of June 12, 2013, (the "Severance Plan"), which provides for payment of certain severance benefits in the event of Qualifying Termination (as that term is defined in the Severance Plan) and related to the Sunoco Logistics Merger, the Energy Transfer/SXL Merger Severance Plan (the "Severance Plan"). In general, the Severance Plan provides payment of two weeks of annual base salary for each year or partial year of employment service, up to a maximum of fifty-two weeks or one year of annual base salary (with a minimum of four weeks of annual base salary) and up to three months of continued group health insurance coverage. The Severance Plan also provides that additional benefits in addition to those provided under the Severance Plan may be paid based on special circumstances, which additional benefits shall be unique and non-precedent setting. The Severance Plan is available to all salaried employees on a nondiscriminatory basis; therefore, amounts that would be payable to the named executive officers upon a Qualified Termination have been excluded from "Compensation Tables - Potential Payments Upon a Termination or Change of Control" below. The SXL Severance Plan, which was adopted in connection with the Sunoco Logistics Merger, provided for an enhanced minimum severance benefit for personnel terminated in connection with the Sunoco Logistics Merger. The SXL Severance Plan provided for two weeks of annual base salary for each year or partial year up to certain maximum levels depending on the employees title. The benefit levels are summarized below:

Employee Level	Minimum Severance Pay	Maximum Severance Pay
Senior Manager or below	8 weeks of Base Pay	26 weeks of Base Pay
Director or Senior Director	16 weeks of Base Pay	39 weeks of Base Pay
Vice President and above	26 weeks of Base Pay	52 weeks of Base Pay

The SXL Severance Plan also provided up to three months of continued group health insurance coverage. In addition, for employees terminated in connection with the Sunoco Logistics Merger received certain accelerated vesting of awards long-term incentive awards under the 2008 Incentive Plan, the 2011 Incentive Plan and the ETP Plan as follows:

Employee Level	Accelerated Vesting of Outstanding LTIP Awards
Senior Manager or below	30% of the unvested outstanding LTIP awards
Director or Senior Director	40% of the unvested outstanding LTIP awards
Vice President and above	50% of the unvested outstanding LTIP awards

In 2017, in connection with Mr. Hennigan's termination of employment, Mr. Hennigan received certain benefits under the SXL Severance Plan, which provided Mr. Hennigan with (i) a severance payment of $637,500.00, which is an amount equal to twelve (12) months of Mr. Hennigan's base salary; and (ii) payment by ETP of the full cost of Mr. Hennigan's premium for continued health insurance coverage under ETP's health insurance plan for a period of three (3) months. In addition, Mr. Hennigan became entitled to acceleration of the vesting of 262,652 unvested restricted units (the "Accelerated Units") awarded to Mr. Hennigan pursuant to the terms of the ETP Plan (formerly the Sunoco Partners LLC Long-Term Incentive Plan, as amended and restated). The Accelerated Units represented consideration of Mr. Hennigan's non-solicit/non-hire covenant in the Separation Agreement and Full Release of Claims executed by Mr. Hennigan after his termination of employment (the "Hennigan Separation Agreement"). As of his termination date, Mr. Hennigan had a total of 415,261 unvested restricted units under the ETP Plan and other than the Accelerated Units, the remaining 152,609 were immediately forfeited upon his termination. Mr. Hennigan also received payout of his DC Plan (as that term is defined below) account in the amount of $4,381,604, this payment was processed in January 2018 as payout from the DC Plan to Mr. Hennigan was subject to the deferred payment rule of IRC Section 409(a).

In the case of Mr. Gvazdauskas, he became a transition employee as of the closing of the Sunoco Logistics Merger and is expected to remain as such until sometime during the latter part of the first quarter of 2018. Upon his termination, Mr. Gvazdauskas will be entitled to receive (i) a severance payment of $221,538.46, which is an amount equal to thirty-six (36) weeks of Mr. Gvazdauskas base salary; and (ii) payment by ETP of the full cost of his premium for continued health insurance coverage under ETP's health insurance plan for a period of three (3) months. In addition, Mr. Gvazdauskas will become entitled to acceleration of the vesting of 30,180 unvested restricted units (the "Accelerated Units") awarded to Mr. Gvazdauskas pursuant to the terms of the ETP Plan. The Accelerated Units will represent consideration for his non-solicit/non-hire covenant in the Separation Agreement and Full Release of Claims to be executed by Mr. Gvazdauskas after his termination of employment (the "Gvazdauskas Separation Agreement"). As of December 31, 2017, Mr. Gvazdauskas had a total of 60,359 unvested restricted units under the ETP Plan and other than the Accelerated Units, the remaining 30,179 will be immediately forfeited upon his termination. All payments to Mr. Gvazdauskas will be subject to his execution and non-revocation of the Gvazdauskas Separation Agreement.

ETP Deferred Compensation Plan. ETP maintains a deferred compensation plan ("DC Plan"), which permits eligible highly compensated employees to defer a portion of their salary and/or bonus until retirement or termination of employment or other

designated distribution. Under the DC Plan, each year eligible employees are permitted to make an irrevocable election to defer up to 50% of their annual base salary, 50% of their quarterly non-vested unit distribution income, and/or 50% of their discretionary performance bonus compensation to be earned for services performed during the following year. Pursuant to the DC Plan, ETP may make annual discretionary matching contributions to participants' accounts; however, ETP has not made any discretionary contributions to participants' accounts and currently has no plans to make any discretionary contributions to participants' accounts. All amounts credited under the DC Plan (other than discretionary credits) are immediately 100% vested. Participant accounts are credited with deemed earnings or losses based on hypothetical investment fund choices made by the participants among available funds.

Participants may elect to have their accounts distributed in one lump sum payment or in annual installments over a period of three or five years upon retirement, and in a lump sum upon other termination. Participants may also elect to take lump-sum in-service withdrawals five years or longer in the future, and such scheduled in-service withdrawals may be further deferred prior to the withdrawal date. Upon a change in control (as defined in the DC Plan) of ETP, all DC Plan accounts are immediately vested in full. However, distributions are not accelerated and, instead, are made in accordance with the DC Plan's normal distribution provisions unless a participant has elected to receive a change of control distribution pursuant to his deferral agreement.

ETP Deferred Compensation Plan for Former Sunoco Executives. The ETP Deferred Compensation Plan for Former Sunoco Executives ("Sunoco Logistics DC Plan") is a deferred compensation plan established by ETP in connection with ETP's acquisition of Sunoco Logistics. In 2012, Mr. Hennigan waived any future rights or benefits to which he otherwise would have been entitled under both the Sunoco, Inc. Executive Retirement Plan ("SERP"), a non-qualified, unfunded plan that provided supplemental pension benefits over and above the benefits under the Sunoco, Inc. Retirement Plan ("SCIRP"), a qualified defined benefit plan sponsored by Sunoco, Inc., under which benefits are subject to IRS limits for pay and amount, and Sunoco Logistics' pension restoration plan, in return for which, $2,789,413 of such deferred compensation benefits was credited to Mr. Hennigan's account under the Sunoco Logistics DC Plan. Mr. Hennigan is the only named executive officer eligible to participate in the Sunoco Logistics DC Plan. Mr. Hennigan's account is 100 percent vested and will be distributed in one lump sum payment upon his retirement or termination of employment, or other designated distribution event, including a change of control (as defined in the Sunoco Logistics DC Plan). His account is credited with deemed earnings (or losses) based on hypothetical investment fund choices made by him among available funds. As noted above, Mr. Hennigan received payout of $4,381,604 in connection with his termination. This payment was processed in January 2018 as Mr. Hennigan's payout from the DC Plan was subject to deferred payment rule of IRC Section 409(a).

Risk Assessment Related to Compensation Structure. ETP believes the compensation plans and programs for the named executive officers, as well as other employees, are appropriately structured and are not reasonably likely to result in material risk to ETP. ETP believes the compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could harm value or reward poor judgment. ETP also believes that compensation is allocated among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, ETP generally does not adjust base annual salaries for the executive officers and other employees significantly from year to year, and therefore the annual base salary of employees is not generally impacted by ETP's overall financial performance or the financial performance of an operating segment. Whether, and to what extent, the named executive officers receive a cash bonus is generally determined based on the achievement of specified financial performance objectives as well as the individual contributions of the named executive officers to ETP's success. Restricted units or phantom units rather than unit options are used for equity awards because restricted units or phantom units retain value even in a depressed market so that employees are less likely to take unreasonable risks to get, or keep, options "in-the-money." Finally, the time-based vesting over five years for long-term incentive awards ensures that employees' interests align with those of the unitholders.

Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for United States federal income tax purposes. Therefore, we believe that the compensation paid to the named executive officers is not subject to the deduction limitations under Section 162(m) of the Internal Revenue Code and therefore is generally fully deductible for United States federal income tax purposes.

Accounting for Unit-Based Compensation

For our unit-based compensation arrangements, including equity-based awards issued to certain of our named executive officers by an affiliate (as discussed above), we record compensation expense over the vesting period of the awards, as discussed further in Note 9 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm and Skidmore are the only members of the Compensation Committee. During 2017, no member of the Compensation Committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with respect to which any of our executive officers served on such company's board of directors. In addition, neither Mr. Grimm nor Mr. Skidmore is a former employee of ours or any of our subsidiaries.

Report of Compensation Committee

The Compensation Committee of the board of directors of our General Partner has reviewed and discussed the section entitled "Compensation Discussion and Analysis" with the management of ETP. Based on this review and discussion, we have recommended to the board of directors of our General Partner that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

The Compensation Committee of the
Board of Directors of Energy Transfer Partners, L.L.C., the
general partner of Energy Transfer Partners GP, L.P., the
general partner of Energy Transfer Partners, L.P.

Michael K. Grimm
David K. Skidmore

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this annual report on Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under those Acts.

Compensation Tables

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus [1] ($)	Equity Awards [2] ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings [3] ($)	All Other Compensation [4] ($)	Total ($)
Kelcy L. Warren [5]	2017	$ 5,926	$ —	$ —	$ —	$ —	$ —	$ —	$ 5,926
Chief Executive Officer	2016	5,920	—	—	—	—	—	58	5,978
	2015	6,338	—	—	—	—	—	—	6,338
Thomas E. Long	2017	480,846	625,100	2,519,954	—	—	—	18,320	3,644,220
Chief Financial Officer	2016	454,154	560,865	2,007,697	—	—	—	14,679	3,037,395
	2015	399,207	480,296	1,447,063	—	—	—	14,282	2,340,848
Marshall S. (Mackie) McCrea, III	2017	1,027,846	1,644,554	9,033,341	—	—	—	16,834	11,722,575
Group Chief Operating Officer and Chief Commercial Officer	2016	1,009,231	1,533,990	8,059,413	—	—	—	14,818	10,617,452
	2015	840,385	1,294,192	6,646,354	—	—	—	14,282	8,795,213
Matthew S. Ramsey [6]	2017	642,404	835,125	3,763,893	—	—	—	18,618	5,260,040
President and Chief Operating Officer	2016	630,769	838,901	3,433,894	—	—	—	87,375	4,990,939
	2015	72,115	200,000	2,749,161	—	—	—	2,587	3,023,863
James M. Wright, Jr.	2017	393,971	453,067	1,087,508	—	—	—	14,402	1,948,948
General Counsel	2016	378,462	377,506	858,464	—	—	47,766	14,447	1,676,645
Michael J. Hennigan[7]	2017	318,750	—	—	—	—	699,022	6,127,145	7,144,917
Former President and Chief Executive Officer of Sunoco Partners LLC	2016	630,769	830,092	3,088,040	—	—	360,066	14,818	4,923,785
	2015	611,537	856,152	3,009,815	—	—	—	16,770	4,494,274
Peter J. Gvazdauskas	2017	320,000	—	—	—	—	—	10,275	330,275
Former Chief Financial Officer and Treasurer of Sunoco Partners LLC	2016	310,384	306,000	686,221	—	—	—	103,651	1,406,256
	2015	261,223	274,283	601,963	—	—	—	80,363	1,217,832

(1) The discretionary cash bonus amounts for named executive officers for 2017 reflect cash bonuses approved by the ETE Compensation Committee and the ETP Compensation Committee, as applicable, in February 2018 that are expected to be paid on or before March 15, 2018.

(2) Equity award amounts reflect the aggregate grant date fair value of unit awards granted for the periods presented, computed in accordance with FASB ASC Topic 718. For Messrs. Long, McCrea and Ramsey, amounts include equity awards of our subsidiaries and/or affiliates, as reflected in the "Grants of Plan-Based Awards Table." See Note 9 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" for additional assumptions underlying the value of the equity awards.

(3) During 2017, Mr. Wright had an unrealized loss of $3,245 in his account balance under the DC Plan.

(4) The amounts reflected for 2017 in this column include (i) matching contributions to the 401(k) plan made by ETP on behalf of the named executive officers of $13,500 for each of Messrs. Long, Ramsey, McCrea and Wright, $12,750 for Mr. Hennigan and $9,846 for Mr. Gvazdauskas, (ii) the dollar value of life insurance premiums paid for the benefit of the named executive officers, (iii) $348,173 in severance payments for Mr. Hennigan, and (iv) $5,475,506 to Mr. Hennigan, which represents the value of the accelerated restricted common units under the ETP Plan as consideration for the restrictive covenant contained in the Hennigan Separation Agreement. The amounts reflected for all periods exclude distribution payments in connection with distribution equivalent rights on unvested unit awards, because the dollar value of such distributions are factored into the grant date fair value reported in the "Unit Awards" column of the Summary Compensation Table at the time that the unit awards and distribution equivalent rights were originally granted. For 2017, distribution payments in connection with

distribution equivalent rights totaled $423,809 for Mr. Long, $1,928,181 for Mr. McCrea, $619,224 for Mr. Ramsey, $187,055 for Mr. Wright, $438,100 for Mr. Hennigan and $147,237 for Mr. Gvazdauskas.

(5) Mr. Warren voluntarily determined that his salary would be reduced to $1.00 per year (plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits). He also does not accept a cash bonus or any equity awards under the equity incentive plans.

(6) Mr. Ramsey serves as a member of the board of directors of ETE, the owner of our General Partner. Mr. Ramsey's other compensation for 2015 does not include $104,400 of director fees paid in cash by ETE. Mr. Ramsey was also a non-employee director of Sunoco LP during 2015, until his November appointment to our General Partner, and his 2015 other compensation does not include $354,210 of director fees paid in cash by Sunoco LP.

(7) The amounts shown for Mr. Hennigan reflect the change in present value for all defined benefit pension plans and supplemental executive retirement plans in which he participated. The applicable disclosure rules require the change in pension value be shown as "$0" if the actual calculation of the change in pension value is less than zero (*i.e.*, a decrease). The decrease in SCIRP pension value for Mr. Hennigan was $49,762 for 2015. The year-over-year change in actuarial present value of Mr. Hennigan's pension benefits under the SCIRP for 2015 was negative because Sunoco, Inc. terminated the SCIRP on October 31, 2014. Mr. Hennigan elected to receive his accrued SCIRP benefit in the form of a lump sum. Because the estimate of the present value of his SCIRP benefit at year-end 2014 assumed that Mr. Hennigan (under the Final Average Pay formula) had a 90 percent probability of electing a lump sum rather than an annuity (which would be transferred to an insurance company with a premium of 47.5%) at December 1, 2015 as part of the plan termination, the change in actuarial present value from the estimate at year-end 2014 was negative because no such premium was paid, resulting in a lower present value of his benefit. Mr. Hennigan did not have any above market preferential payments on deferred compensation during 2017, 2016 or 2015.

Grants of Plan-Based Awards Table

Name	Grant Date	All Other Unit Awards: Number of Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($ / Unit)	Grant Date Fair Value of Unit Awards[1]
ETP Unit Awards:					
Kelcy L. Warren	N/A	—	—	$ —	$ —
Thomas E. Long	N/A	—	—	—	—
Marshall S. (Mackie) McCrea, III	N/A	—	—	—	—
Matthew S. Ramsey	N/A	—	—	—	—
James M. Wright, Jr.	12/21/2017	62,250	—	—	1,087,508
Michael J. Hennigan	N/A	—	—	—	—
Peter J. Gvazdauskas	N/A	—	—	—	—
ETE Unit Awards:					
Thomas E. Long	12/20/2017	121,074	—	—	2,035,254
Marshall S. (Mackie) McCrea, III	12/20/2017	537,379	—	—	9,033,341
Matthew S. Ramsey	12/20/2017	223,908	—	—	3,763,893
Sunoco LP Unit Awards:					
Thomas E. Long	12/21/2017	17,097	—	—	484,700

(1) We have computed the grant date fair value of unit awards in accordance with FASB ASC Topic 718, as further described above and in Note 9 to our consolidated financial statements.

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

A description of material factors necessary to understand the information disclosed in the tables above with respect to salaries, bonuses, equity awards, nonqualified deferred compensation earnings (and losses), and 401(k) plan contributions can be found in the Compensation Discussion and Analysis that precedes these tables.

Outstanding Equity Awards at 2017 Fiscal Year-End Table

		Unit Awards [1]	
Name	**Grant Date[1]**	**Number of Units That Have Not Vested[2] (#)**	**Market or Payout Value of Units That Have Not Vested [3] ($)**
ETP Unit Awards:			
Kelcy L. Warren	—	—	$ —
Thomas E. Long	12/29/2016	59,053	1,058,229
	12/9/2015	27,788	497,952
	12/4/2015	11,208	200,847
	12/16/2014	8,192	146,792
	12/5/2013	6,516	116,767
Marshall S. (Mackie) McCrea, III	12/29/2016	336,386	6,028,028
	12/9/2015	185,261	3,319,868
	12/4/2015	93,390	1,673,549
	12/16/2014	37,590	673,613
	12/5/2014	16,454	294,863
	12/30/2013	41,625	745,920
	12/3/2013	21,840	391,373
Matthew S. Ramsey	12/29/2016	143,438	2,570,400
	12/9/2015	115,785	2,074,867
James M. Wright, Jr.	12/21/2017	62,250	1,115,520
	12/29/2016	35,859	642,593
	12/9/2015	21,930	392,986
	12/16/2014	5,462	97,886
	12/30/2013	4,440	79,565
Michael J. Hennigan	N/A	—	—
Peter J. Gvazdauskas	12/12/2016	29,668	531,651
	12/5/2015	23,350	418,432
	12/5/2014	3,661	65,605
	12/5/2013	3,680	65,946
Sunoco LP Unit Awards:			
Thomas E. Long	12/21/2017	17,097	485,555
	12/29/2016	22,210	630,764
	12/16/2015	14,125	401,150
Matthew S. Ramsey	1/2/2015	2,035	57,794
	11/10/2014	299	8,486
ETE Unit Awards:			
Thomas E. Long	12/20/2017	121,074	2,089,737
Matthew S. Ramsey	12/20/2017	223,908	3,864,652
Marshall S. (Mackie) McCrea, III	12/20/2017	537,379	9,275,162

(1) In connection with the April 28, 2017 merger between ETP and Sunoco Logistics, each outstanding unvested ETP restricted unit converted into 1.5 units of Sunoco Logistics, maintaining the same terms as the original ETP award. In connection with the merger, Sunoco Logistics changed its name to Energy Transfer Partners, L.P. Certain of these outstanding awards represent ETP awards that converted into Sunoco Logistics awards in connection with the merger.

(2) ETP and Sunoco LP common unit awards outstanding vest as follows:

- at a rate of 60% in December 2020 and 40% in December 2022 for awards granted in December 2017;
- at a rate of 60% in December 2019 and 40% in December 2021 for awards granted in December 2016;
- at a rate of 60% in December 2018 and 40% in December 2020 for awards granted in January 2015 and December 2015;

- 100% in December 2019 for the remaining outstanding portion of awards granted in December 2014 and November 2015; and
- 100% in December 2018 for the remaining outstanding portion of all other awards.

ETE common unit awards outstanding vest at a rate of 60% in December 2020 and 40% in December 2022 for awards granted in December 2017.

(3) Market value was computed as the number of unvested awards as of December 31, 2017 multiplied by the closing price of our Common Units or Sunoco LP or ETE common units, accordingly, on December 31, 2017.

Option Exercises and Units Vested Table

	Unit Awards	
Name	**Number of Units Acquired on Vesting (1) (#)**	**Value Realized on Vesting(1) ($)**
ETP Unit Awards:		
Kelcy L. Warren	—	$ —
Thomas E. Long	18,471	301,576
Matthew S. Ramsey	—	—
Marshall S. (Mackie) McCrea, III	107,733	1,758,957
James M. Wright, Jr.	11,794	192,544
Michael J. Hennigan	262,652	5,475,506
Peter J. Gvazdauskas	7,492	122,322

(1) Amounts presented represent the number of units subject to awards that vested during 2017 and the value realized upon vesting of such units, which is calculated as the number of units subject to vesting multiplied by the closing price of our Common Units upon the vesting date.

We have not issued option awards.

Nonqualified Deferred Compensation

The following table provides the voluntary salary deferrals made by the named executive officers in 2017 under the DC Plan and, in the case of Mr. Hennigan, the Sunoco Logistics DC Plan.

Name	**Executive Contributions in Last FY ($)**	**Registrant Contributions in Last FY ($)**	**Aggregate Earnings in Last FY ($)**	**Aggregate Withdrawals/Distributions ($)**	**Aggregate Balance at Last FYE ($)**
Kelcy L. Warren	$ —	$ —	$ —	$ —	$ —
Thomas E. Long	—	—	—	—	—
Matthew S. Ramsey	—	—	—	—	—
James M. Wright, Jr.	—	—	(3,245)	—	70,202
Michael J. Hennigan	—	—	699,022	(4,381,604)	—

A description of the key provisions of the DC Plan and the Sunoco Logistics DC Plan can be found in the Compensation Discussion and Analysis that precedes these tables above.

Potential Payments Upon a Termination or Change of Control

Equity Awards. As discussed in the Compensation Discussion and Analysis above, the restricted unit awards under the 2008 Incentive Plan, the 2011 Incentive Plan, as well as, the ETP Plan and the Sunoco LP equity plan, generally require the continued employment of the recipient during the vesting period, provided however, unvested awards will be accelerated in the event of the death or disability of the award recipient prior to the applicable vesting period being satisfied. In addition, in the event of a change in control, all awards granted in 2014, 2015 and 2016 under the 2008 Incentive Plan or the 2011 Incentive Plan, as applicable, and/or the ETP Plan and the Sunoco LP equity plan would be accelerated. For awards granted under the 2008 Incentive Plan or the ETP Plan and the Sunoco LP equity plan prior to December 2014, unless otherwise specified in the applicable award agreement, unvested awards may also become vested upon a change in control at the discretion of the applicable compensation committee. This discussion assumes a scenario in which the ETP Compensation Committee, the Sunoco Logistics Compensation Committee

or the compensation committee of the general partner of Sunoco LP did not exercise their discretion to accelerate unvested awards in connection with a change in control of the Partnership.

The awards under the 2008 Incentive Plan, the 2011 Incentive Plan and the 2014, 2015 and 2016 awards under the ETP Plan (formerly the Sunoco Logistics Plan) and Sunoco LP equity incentive plan all provide for acceleration of vesting in the event of the death or disability of the award recipient. In addition, the ETP Compensation Committee has approved a retirement provision, which provides that employees with at least ten years of service with the general partner, who leave the general partner voluntarily due to retirement, are eligible for accelerated vesting of 40% of his or her award for named executive officers age 65 to 68, or 50% of his or her award for named executive officers over age 68. Under the assumption described above, none of the restricted units granted in December 2016 would vest upon a named executive officer's retirement because none of such officers met the age criteria for vesting at such time. For 2015 and 2016, the Sunoco Logistics Compensation Committee included a provision in their award agreements which provided that an employee with at least ten years of service, who leaves employment voluntarily due to retirement, is eligible for accelerated vesting of 40% of his or her award from age 65 to 68 or 50% of his or her award over age 68. The acceleration of the awards is subject to the applicable provisions of IRC Section 409(A).

In the event of death, the named executive officers participate in the life insurance plans offered to all employees (i.e., life insurance benefits equal to one and one-half times the named executive officer's annual base salary, up to a maximum of $750,000 plus any supplemental life insurance elected and paid for by the named executive officer).

In 2017, in connection with Mr. Hennigan's termination of employment, Mr. Hennigan received certain benefits under the SXL Severance Plan, which provided Mr. Hennigan with accelerated of the vesting of 262,652 unvested restricted units (the "Accelerated Units") awarded to Mr. Hennigan pursuant to the terms of the ETP Plan. The Accelerated Units represented consideration of Mr. Hennigan's non-solicit/non-hire covenant in the Separation Agreement and Full Release of Claims executed by Mr. Hennigan after his termination of employment (the "Hennigan Separation Agreement"). As of his termination date, Mr. Hennigan had a total of 415,261 unvested restricted units under the ETP Plan and other than the Accelerated Units, the remaining 170,609 were immediately forfeited upon his termination.

In the case of Mr. Gvazdauskas, he became a transition employee as of the closing of the Sunoco Logistics Merger and is expected to remain as such until the latter part of the first quarter 2018. Upon his termination, Mr. Gvazdauskas will be entitled to receive acceleration of the vesting of 30,180 unvested restricted units (the "Accelerated Units") awarded to Mr. Gvazdauskas pursuant to the terms of the ETP Plan. The Accelerated Units will represent consideration for his non-solicit/non-hire covenant in the Separation Agreement and Full Release of Claims to be executed by Mr. Gvazdauskas after his termination of employment (the "Gvazdauskas Separation Agreement"). As of December 31, 2017, Mr. Gvazdauskas had a total of 60,359 unvested restricted units under the ETP Plan and other than the Accelerated Units, the remaining 30,179 will be immediately forfeited upon his termination.

Deferred Compensation Plans. As discussed in the Compensation Discussion and Analysis above, all amounts under the DC Plan and the Sunoco Logistics Plan (other than discretionary credits) are immediately 100% vested. Upon a change in control (as defined in the DC Plan and/or the Sunoco Logistics DC Plan), distributions from the respective plans would be made in accordance with the normal distribution provisions of the respective plan. A change in control is generally defined in the DC Plan and the Sunoco Logistics Plan as any change in control event within the meaning of Treasury Regulation Section 1.409A-3(i)(5).

As noted above, Mr. Hennigan received payout of $4,381,604 in connection with his termination. This payment was processed in January 2018 as Mr. Hennigan's payout from the DC Plan was subject to deferred payment rule of IRC Section 409(a).

CEO Pay Ratio

In accordance with Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, set forth below is information about the relationship of the annual total compensation of Mr. Warren, ETP's Chairman and Chief Executive Officer and the annual total compensation of our employees.

For the 2017 calendar year:

The annual total compensation of Mr. Warren, as reported in the Summary Compensation Tables of this Item 11was $5,926; and

The median total compensation of the employees supporting ETP (other than Mr. Warren) was $115,226.

Based on this information, for 2017 the ration of the annual total compensation of Mr. Warren to the median of the annual total compensation of the 8,494 employees supporting ETP as of December 31, 2017 was approximately 1 to 19 as Mr. Warren has voluntarily elected not to accept any salary, bonus or equity incentive compensation (other than a salary of $1.00 per year plus an amount sufficient to cover his allocated employee premium contributions for health and welfare benefits).

To identify the median of the annual total compensation of the employees supporting ETP, the following steps were taken:

1. It was determined that, as of December 31, 2017, the applicable employee populations consisted of 8,494 with all of the identified individuals being employed in the United States. This population consisted of all of our full-time and part-time employees. We did not engage any independent contractors in 2017 that are required to be included in our employee population for the CEO pay ratio evaluation.
2. To identify the "median employee" from our employee population, we compared the total earnings of our employees as reflected in our payroll records as reported on Form W-2 for 2017.
3. We identified our median employee using W-2 reporting and applied this compensation measure consistently to all of our employees required to be included in the calculation. We did not make any cost of living adjustments in identifying the "median employee".
4. Once we identified our median employee, we combined all elements of the employee's compensation for 2017 resulting in an annual compensation of $115,226. The difference between such employee's total earnings and the employee's total compensation represents the estimated value of the employee's health care benefits (estimated for the employee and such employee's eligible dependents at $10,800) and the employee's 401(k) matching contribution and profit sharing contribution (estimated at $5,846 per employee, includes $3,633 per employee on average matching contribution and $2,213 per employee on average profit sharing contribution (employees earning over $175,000 in base are ineligible for profit sharing)).
5. With respect to Mr. Warren, we used the amount reported in the "Total" column of our 2017 Summary Compensation Table under this Item 11.

Director Compensation

The Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of our General Partner. In 2017, non-employee directors each received an annual fee of $50,000 in cash. Additionally, the Chairman of the Audit Committee receives an annual fee of $15,000 and the members of the Audit Committee receive an annual fee of $10,000. The Chairman of the ETP Compensation Committee receives an annual fee of $7,500 and the members of the ETP Compensation Committee receive an annual fee of $5,000. In 2017, members of the Conflicts Committee received cash payments on a to-be-determined basis for each Conflicts Committee assignment. Employee directors, including Mr. Warren, do not receive any fees for service as directors. In addition, the non-employee directors participate in the 2008 Incentive Plan. Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, ETP, or a subsidiary, who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of 2,500 unvested ETP Common Units. In 2017, non-employee directors received annual grants of restricted Common Units equal to an aggregate of $100,000 divided by the closing price of our Common Units on the date of grant, which will vest 60% after the third year and the remaining 40% after the fifth year after the grant date.

The compensation paid to the non-employee directors of our General Partner in 2017 is reflected in the following table:

Name	Fees Paid in Cash[1] ($)	Unit Awards[2] ($)	All Other Compensation ($)	Total ($)
Ted Collins, Jr.	$ 94,010	$ 100,372	$ —	$ 194,382
Michael K. Grimm	147,310	100,372	—	247,682
David K. Skidmore	141,844	100,372	—	242,216
Former Sunoco Logistics Board Members [3]:				
Steven R. Anderson	84,125	100,372	—	184,497
Scott A. Angelle	66,308	100,372	—	166,680
Basil Leon Bray	67,141	100,372	—	167,513

(1) Fees paid in cash are based on amounts paid during the period.

(2) Unit award amounts reflect the aggregate grant date fair value of awards granted based on the market price of Common Units as of the grant date.

(3) Upon completion of the Sunoco Logistics Merger, the unvested unit awards of the former board members of the general partner of Sunoco Logistics were vested in full.

As of December 31, 2017, Messrs. Collins and Grimm each had 12,455 unit awards outstanding and Mr. Skidmore had 13,319 unit awards outstanding.

For 2018, the Board of our General Partner has approved modifications to the compensation of non-employee directors of our General Partner. The directors will receive an annual retainer fee of $100,000 in cash, up from $50,000 in 2017. In addition, the

Chairman of the Audit Committee will receive an annual fee of $25,000, up from $15,000 in 2017 and the members of the Audit Committee will receive an annual fee of $15,000, up from $10,000. The Chairman of the ETP Compensation Committee will receive an annual fee of $15,000, up from 7,500 in 2017 and the members of the ETP Compensation Committee receive an annual fee of $7,500, up from $5,000 in 2017. The fees for membership on the Conflicts Committee will continue to be determined on a per instance basis for each Conflicts Committee assignment.

Additionally for 2018, annual grants of restricted Common Units will remain equal to an aggregate of $100,000 to be divided by the closing price of our Common Units on the date of grant, which will vest 60% after the third year and the remaining 40% after the fifth year after the grant date.

The proposed compensation changes for the non-employee directors for 2018 were developed in consultation with Mr. Warren after considering the results of a review of directors' compensation by Longnecker during 2017.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Equity Compensation Plan Information

The following table sets forth, in tabular format, a summary of certain information related to our equity incentive plans as of December 31, 2017:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[a]	Weighted-average exercise price of outstanding options, warrants and rights[b]	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column[a])[c]
Equity compensation plans approved by security holders	14,201,612	$ —	8,393,837
Equity compensation plans not approved by security holders	—	—	—
Total	14,201,612	$ —	8,393,837

Energy Transfer Partners, L.P. Units

The following table sets forth certain information as of February 16, 2018, regarding the beneficial ownership of our securities by certain beneficial owners, each director and named executive officer of our General Partner and all directors and executive officers of our General Partner as a group. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

Title of Class	Name and Address of Beneficial Owner[1]	Beneficially Owned[2][3]	Percent of Class
Common Units	Kelcy L. Warren	2,031,646	*
	Thomas E. Long	51,868	*
	Marshall S. (Mackie) McCrea, III	330,430	*
	Matthew S. Ramsey	23,033	*
	James M. Wright, Jr.	33,893	*
	A. Troy Sturrock	19,937	*
	Michael J. Hennigan	573,543	*
	Peter J. Gvazdauskas	35,232	*
	Michael K. Grimm	61,246	*
	David K. Skidmore [4]	33,250	*
	Ray C. Davis [5]	544,200	*
	W. Brett Smith	14,800	*
	All Directors and Executive Officers as a Group (12 Persons)	3,753,078	*
	ETE [6]	27,535,127	2.4%
	ALPS Advisors, Inc. [7]	59,554,331	5.1%
Class E Units	Heritage Holdings, Inc.[8]	8,853,832	100%
Class G Units	Sunoco, Inc. [9]	90,706,000	100%
Class K Units	Sunoco, Inc. [9]	64,102,567	100%
Class K Units	Heritage Holdings, Inc. [8]	19,509,477	100%
Class K Units	SUG Holding Company LLC	17,913,385	100%

* Less than 1%

(1) Unless otherwise indicated, the address for all beneficial owners listed above is 8111 Westchester Drive, Suite 600, Dallas, Texas 75225. The address for Mr. McCrea is 800 E. Sonterra Blvd., San Antonio, Texas 78258. The address for Mr. Hennigan is 3807 West Chester Pike, Newtown Square, Pennsylvania 19073. The address for Sunoco, Inc. is 3801 West Chester Pike, Newtown Square, Pennsylvania, 19073. The address for ALPS Advisors, Inc. is 1290 Broadway, Suite 1100, Denver, Colorado 80203.

(2) Beneficial ownership for the purposes of the foregoing table is defined by Rule 13d-3 under the Exchange Act. Under that rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct the voting thereof or to dispose or direct the disposition thereof or has the right to acquire either of those powers within sixty (60) days.

(3) Due to the ownership by certain officers and directors of the general partner of ETE of equity interests in ETE (either directly or through one or more entities) and due to their positions as directors of the general partner of ETE, they may be deemed to beneficially own the limited partnership interests held by ETE, to the extent of their respective interests therein. Any such deemed ownership is not reflected in the table.

(4) Total includes 4,443 common units held in a trust for the benefit of Mr. Skidmore's daughter over which Mr. Skidmore has voting power. Mr. Skidmore disclaims beneficial ownership of such units.

(5) Includes 85,605 units held by RCD Stock Holdings, LLC and 458,595 units held by Avatar BW, Ltd.

(6) ETE owns all member interests of Energy Transfer Partners, L.L.C and all of the Class A limited partner interests and Class B limited partner interests in Energy Transfer Partners GP, L.P. Energy Transfer Partners, L.L.C. is the general partner of Energy Transfer Partners GP, L.P. with a 0.01% general partner interest. LE GP, LLC, the general partner of ETE, may be

deemed to beneficially own the Common Units owned of record by ETE. The members of LE GP, LLC are Ray C. Davis and Kelcy L. Warren.

(7) Information reflected herein for ALPS Advisors, Inc. ("AAI") is based on its Schedule 13G filed on February 6, 2018. AAI, a registered investment adviser, furnishes investment advice to investment companies registered under the Investment Company Act of 1940 (collectively referred to as the "Funds"). In its role as investment advisor, AAI has voting and/or investment power over the ETP common units that are owned by the Funds, and may be deemed to be the beneficial owner of the ETP common units held by the Funds. However, all units reported in this table are owned by the Funds. AAI disclaims beneficial ownership of such common units. The Funds have the right to receive or the power to direct the receipt of dividends from, or the proceeds from the sale of ETP common units held in their respective accounts. Alerian MLP ETF is an investment company registered under the Investment Company Act of 1940 and is one of the Funds to which AAI provides investment advice. The interest of Alerian MLP ETF, as reported in its February 6, 2018 Schedule 13G, amounted to 59,348,430 common units, or 5.1% of the total outstanding ETP common units.

(8) The Partnership indirectly owns 100% of the common stock of Heritage Holdings, Inc.

(9) The Partnership indirectly owns 100% of the common stock of Sunoco, Inc.

In connection with the Parent Company Credit Agreement, ETE and certain of its subsidiaries entered into a Pledge and Security Agreement (the "Security Agreement") with Credit Suisse AG, Cayman Islands Branch, as collateral agent (the "Collateral Agent"). The Security Agreement secures all of ETE's obligations under the Parent Company Credit Agreement and grants to the Collateral Agent a continuing first priority lien on, and security interest in, all of ETE's and the other grantors' tangible and intangible assets.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

For a discussion of director independence, see Item 10. "Directors, Executive Officers and Corporate Governance."

As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine whether the transaction is fair and reasonable to the Partnership. The Partnership's board of directors makes the determinations as to whether there exists a related-party transaction in the normal course of reviewing transactions for approval as the Partnership's board of directors is advised by its management of the parties involved in each material transaction as to which the board of directors' approval is sought by the Partnership's management. In addition, the Partnership's board of directors makes inquiries to independently ascertain whether related parties may have an interest in the proposed transaction. While there are no written policies or procedures for the board of directors to follow in making these determinations, the Partnership's board makes those determinations in light of its contractually-limited fiduciary duties to the Unitholders. The Partnership Agreement provides that any matter approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all the partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Unitholders (see "Risks Related to Conflicts of Interest" in "Item 1A. Risk Factors" in this annual report).

ETE owns directly and indirectly the general partner interest in ETP GP, 100% of the ETP Incentive Distribution Rights and 27.5 million ETP Common Units.

We have a shared services agreement in which we provide various general and administrative services for ETE. See discussion in Note 14 to our consolidated financial statements.

We previously had an operating lease agreement with the former owners of ETG, including Mr. Warren and Mr. Davis. We paid these former owners $5 million in annual operating lease payments during the term of the lease and made a one-time payment of $8.8 million in August 2017 and we retained the equipment when the lease expired at that time. With respect to the related party transaction with ETG, the Conflicts Committee of ETP met numerous times prior to the consummation of the transaction to discuss the terms of the transaction. The committee made the determination that the sale of ETG to ETP was fair and reasonable to ETP and that the terms of the operating lease between ETP and the former owners of ETG are fair and reasonable to ETP.

We received $6 million, $21 million and $23 million in management fees from ETE for the provision of various general and administrative services for ETE's benefit for the years ended December 31, 2017, 2016, and 2015, respectively.

On July 27, 2016, the Partnership issued to ETE an aggregate amount of 180 Class J units representing limited partner interests in the Partnership (the "Class J Units"). A portion of the additional Class J Units will be issued during each of 2016, 2017 and 2018. Each Class J Unit is entitled to an allocation of $10.0 million of depreciation, amortization, depletion or other form of cost-recovery during the year in which such Class J Unit was issued; no Class J Unit is entitled to any other allocations of depreciation, amortization, depletion or other cost-recovery in any other year, and such units are not entitled to any cash distributions at any time. In exchange for the issuance of the Class J Units, ETP's partnership agreement was amended to further reduce incentive

distributions commencing with the quarter ended June 30, 2016 and ending with the quarter ending December 31, 2017, in an aggregate amount of $720 million.

In March 2016, ETP contributed to Sunoco LP its remaining 68.42% interest in Sunoco, LLC and 100% interest in the legacy Sunoco, Inc. retail business for $2.23 billion. Sunoco LP paid $2.20 billion in cash, including a working capital adjustment and issued 5.7 million Sunoco LP common units to Retail Holdings, a wholly-owned subsidiary of the Partnership.

Class K Units

On December 29, 2016, the Partnership issued to certain of its indirect subsidiaries, in exchange for cash contributions and the exchange of outstanding common units representing limited partner interests in the Partnership, Class K Units, each of which is entitled to a quarterly cash distribution of $0.67275 per Class K Unit prior to ETP making distributions of available cash to any class of units, excluding any cash available distributions or dividends or capital stock sales proceeds received by ETP from ETP Holdco. If the Partnership is unable to pay the Class K Unit quarterly distribution with respect to any quarter, the accrued and unpaid distributions will accumulate until paid and any accumulated balance will accrue 1.5% per annum until paid. As of December 31, 2017, a total of 101.5 million Class K Units were held by wholly-owned subsidiaries of ETP.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following sets forth fees billed by Grant Thornton LLP for the audit of our annual financial statements and other services rendered (dollars in millions):

	Years Ended December 31,	
	2017	2016
Audit fees[1]	$ 7.5	$ 6.4
Audit related fees[2]	—	0.4
Tax fees[3]	—	0.1
Total	$ 7.5	$ 6.9

(1) Includes fees for audits of annual financial statements of our companies, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC and services related to the audit of our internal control over financial reporting.

(2) Includes fees in 2016 for financial statement audits and interim reviews of subsidiary entities in connection with contribution and sale transactions. Includes fees in 2016 in connection with the service organization control report on Panhandle's centralized data center.

(3) Includes fees related to state and local tax consultation.

Pursuant to the charter of the Audit Committee, the Audit Committee is responsible for the oversight of our accounting, reporting and financial practices. The Audit Committee has the responsibility to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and establish the fees and other compensation to be paid to our external auditors. The Audit Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by Grant Thornton LLP, including audit services, audit-related services, tax services and other services, must be pre-approved by the Audit Committee. All fees paid or expected to be paid to Grant Thornton LLP for fiscal years 2017 and 2016 were pre-approved by the Audit Committee in accordance with this policy.

The Audit Committee reviews the external auditors' proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the auditors' internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;

- the independence of the external auditors;
- the aggregate fees billed by our external auditors for each of the previous two years; and
- the rotation of the lead partner.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this Report:	Page
(1) Financial Statements – see Index to Financial Statements	F - 1
(2) Financial Statement Schedules – None	
(3) Exhibits – see Index to Exhibits	146

ITEM 16. FORM 10-K SUMMARY

None.

INDEX TO EXHIBITS

The exhibits listed on the following Exhibit Index are filed as part of this report. Exhibits required by Item 601 of Regulation S-K, but which are not listed below, are not applicable.

Exhibit Number	Description
2.1	Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011 (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed October 18, 2011).
2.2	Amendment No. 1, dated December 1, 2011, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011 (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed December 7, 2011).
2.3	Amendment No. 2, dated January 11, 2012, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011 (incorporated by reference to Exhibit 10.1 to Exhibit 2.1 to Registrant's Form 8-K filed on January 13, 2012).
2.4	Agreement and Plan of Merger, dated as of April 29, 2012 by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc. and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on May 1, 2012).
2.5	Amendment No. 1, dated as of June 15, 2012, to the Agreement and Plan of Merger, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc., and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.2 to Registrant's Form 8-K filed on June 20, 2012).
2.6	Transaction Agreement, dated as of June 15, 2012, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage Holdings, Inc., Energy Transfer Equity, L.P., ETE Sigma Holdco, LLC and ETE Holdco Corporation (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on June 20, 2012).
2.7	Agreement and Plan of Merger, dated as of April 27, 2014 by and among Energy Transfer Partners, L.P., Drive Acquisition Corporation, Heritage Holdings, Inc., Energy Transfer Partners GP, L.P., Susser Holdings Corporation, and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on April 28, 2014).
2.8	Agreement and Plan of Merger, dated as of January 25, 2015, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Regency Energy Partners LP, Regency GP LP and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on January 26, 2015).
2.9	Amendment No. 1 to Agreement and Plan of Merger, dated as of February 18, 2015, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Rendezvous I LLC, Rendezvous II LLC, Regency Energy Partners LP, Regency GP LP, ETE GP Acquirer LLC and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.2 to Registrant's Form 8-K filed on February 19, 2015).
2.10	Contribution Agreement, dated October 24, 2016 by and among Energy Transfer Partners, L.P. and NGP X US Holdings, LP, PennTex Midstream Partners, LLC, MRD Midstream LLC, WHR Midstream LLC and certain individual investors and managers named therein (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed October 26, 2016).
2.11	Membership Interest Purchase Agreement, dated as of August 2, 2016, by and between Bakken Holdings Company LLC and MarEn Bakken Company LLC (incorporated by reference to Exhibit 2.2 to the Registrant's Form 10-Q for the quarter ended September 30, 2016).
2.12	First Amendment, dated December 14, 2016, to the Membership Interest Purchase Agreement, dated as of August 2, 2016, by and between Bakken Holdings Company LLC and MarEn Bakken Company LLC (incorporated by reference to Exhibit 2.12 to the Registrant's Form 10-K for the year ended December 31, 2016).
2.13	Agreement and Plan of Merger, dated as of November 20, 2016, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Sunoco Logistics Partners L.P., Sunoco Partners LLC and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporate by reference to Exhibit 2.1 of Form 8-K File No. 1-11727, filed November 21, 2016).

Exhibit Number	Description
2.14	Amendment No. 1 to Agreement and Plan of Merger, dated as of December 16, 2016, by and among Sunoco Logistics Partners L.P., Sunoco Partners LLC, SXL Acquisition Sub LLC, SXL Acquisition Sub LP, Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., ETP Acquisition Sub, LLC and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.2 of Form 8-K File No. 1-11727, filed December 21, 2016).
2.15	Contribution Agreement, dated as of January 15, 2018, by and among USA Compression Partners, LP, Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., ETC Compression, LLC and, solely for certain purposes therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed January 16, 2018).
2.16	Purchase Agreement, dated as of January 15, 2018, by and among USA Compression Holdings, LLC, Energy Transfer Equity, L.P., Energy Transfer Partners, L.L.C. and, solely for certain purposes therein, R/C IV USACP Holdings, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 2.2 to the Registrant's Form 8-K filed January 16, 2018).
2.17	Contribution Agreement, dated as of July 30, 2017, by and among Energy Transfer Interstate Holdings, LLC, ET Rover Pipeline LLC and BCP Renaissance, L.L.C. (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed August 2, 2017).
3.1	Fourth Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. dated as of April 28, 2017 (incorporated by reference to Exhibit 3.4 to the Registrant's Form 8-K filed April 28, 2017).
3.1.1	Amendment No. 1, dated November 16, 2017, to the Fourth Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated April 28, 2009 (incorporated by reference to Exhibit 3.1 to Registrant's Form 8-K filed on November 16, 2017).
3.2	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P. (formerly known as Sunoco Logistics Partners L.P.) (incorporated by reference to Exhibit 3.3 to Registrant's Form 8-K filed on April 28, 2017).
3.3	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to Exhibit 3.5 to the Registrant's Form 10-Q for the quarter ended May 31, 2007).
3.3.1	Amendment No. 2, dated March 26, 2012, to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P., dated as of April 17, 2007 (incorporated by reference to Exhibit 3.2 to Registrant's Form 8-K filed on March 28, 2012).
3.4	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed August 10, 2010).
3.4.1	Amendment No. 1, dated March 26, 2012, to the Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C., dated as of August 10, 2010 (incorporated by reference to Exhibit 3.3 to Registrant's Form 8-K filed on March 28, 2012).
3.5	Certificate of Limited Partnership of Sunoco Logistics Partners L.P. (incorporated by reference to Exhibit 3.1 to Form S-1, File No. 333-71968, filed October 22, 2001).
3.5.1	Amendment to the Certificate of Limited Partnership of Sunoco Logistics Partners L.P. dated as of August 28, 2015 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-31219, filed September 1, 2015).
3.5.2	Amendment to the Certificate of Limited Partnership of Sunoco Logistics Partners L.P. dated as of April 28, 2017 (incorporated by reference to Exhibit 3.3 to the Registrant's Form 8-K filed April 28, 2017).
3.6	Certificate of Limited Partnership of Sunoco Logistics Operations L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 1 to Form S-1, File No. 333-71968, filed December 18, 2001).
3.7	First Amended and Restated Agreement of Limited Partnership of Sunoco Logistics Partners Operations L.P., dated as of February 8, 2002 (incorporated by reference to Exhibit 3.5 of Form 10-K, File No. 1-31219, filed April 1, 2002).
3.8	Certificate of Formation of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.13 to the Registrant's Form 10-Q for the quarter ended March 31, 2010).
3.8.1	Certificate of Amendment of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.13.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2010).
3.9	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to Exhibit 3.14 to the Registrant's Form 10-Q for the quarter ended March 31, 2010).
4.1	Registration Rights Agreement, dated April 30, 2013, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed on May 1, 2013).
4.2	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed January 19, 2005).

Exhibit Number	Description
4.3	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 of the Registrant's Form 8-K filed on January 19, 2005).
4.4	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 10.45 to the Registrant's Form 10-Q for the quarter ended February 28, 2005).
4.5	Form of Senior Indenture of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 4.11 to the Registrant's Form S-3 filed August 9, 2006).
4.6	Form of Subordinated Indenture of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 4.12 to the Registrant's Form S-3 filed August 9, 2006).
4.7	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.13 to the Registrant's Form 10-K for the year ended August 31, 2006).
4.8	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 25, 2006).
4.9	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed March 31, 2008).
4.10	Seventh Supplemental Indenture dated December 23, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed December 23, 2008).
4.10.1	Eighth Supplemental Indenture dated April 7, 2009, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 of the Registrant's Form 8-K filed on April 7, 2009).
4.11	Ninth Supplemental Indenture, dated as of May 12, 2011, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed May 12, 2011).
4.12	Tenth Supplemental Indenture, dated as of January 17, 2012, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed January 17, 2012).
4.13	Eleventh Supplemental Indenture dated as of January 22, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 1.1 to the Registrant's Form 8-K filed January 22, 2013).
4.14	Twelfth Supplemental Indenture dated as of January 24, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed June 26, 2013).
4.15	Thirteenth Supplemental Indenture dated as of September 19, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed September 19, 2013).
4.16	Fourteenth Supplemental Indenture dated as of March 12, 2015 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed on March 12, 2015).
4.17	Fifteenth Supplemental Indenture dated as of June 23, 2015 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.3 to the Registrant's Form 8-K filed June 23, 2015).
4.18	Sixteenth Supplemental Indenture, dated as of January 17, 2017 between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K, File No. 1-11727, filed January 17, 2017).
4.19	Seventeenth Supplemental Indenture, dated as of December 1, 2017 between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 10.8 to the Registrant's Form 8-K, File No. 1-31219, filed December 6, 2017).

Exhibit Number	Description
4.20	Indenture, dated as of March 31 2009, between Sunoco, Inc. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 5, 2012).
4.21	First Supplemental Indenture, dated as of March 31, 2009, between Sunoco, Inc. and U.S. Bank National Association, as trustee, to the Indenture, dated as of March 31, 2009, relating to Sunoco, Inc.'s 9.625% Senior Notes due 2015 (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed October 5, 2012).
4.22	Second Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as trustee, to Indenture, dated as of March 31, 2009 (incorporated by reference to Exhibit 4.3 to the Registrant's Form 8-K filed October 5, 2012).
4.23	Indenture, dated as of June 30, 2000, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A. (incorporated by reference to Exhibit 4.4 to the Registrant's Form 8-K filed October 5, 2012).
4.24	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of June 30, 2000 (incorporated by reference to Exhibit 4.7 to the Registrant's Form 8-K filed October 5, 2012).
4.25	Second Supplemental Indenture, dated December 1, 2017 among Energy Transfer Partners, L.P., and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.5 of Form 8-K, File No. 1-31219, filed December 6, 2017).
4.26	Indenture, dated as of May 15, 1994, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., relating to Sunoco, Inc.'s 9.00% Debentures due 2024 (incorporated by reference to Exhibit 4.8 to the Registrant's Form 8-K filed October 5, 2012).
4.27	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of May 15, 1994 (incorporated by reference to Exhibit 4.9 to the Registrant's Form 8-K filed October 5, 2012).
4.28	Sixteenth Supplemental Indenture, dated as of September 21, 2017, by and among Sunoco Logistics Partners Operations L.P., as issuer, Energy Transfer Partners, L.P., as guarantor, and U.S. Bank National Association, as successor trustee (incorporated by reference to Exhibit 4.4 of Form 8-K filed September 25, 2017).
4.29	Fifteenth Supplemental Indenture, dated as of September 21, 2017, by and among Sunoco Logistics Partners Operations L.P., as issuer, Energy Transfer Partners, L.P., as guarantor, and U.S. Bank National Association, as successor trustee (incorporated by reference to Exhibit 4.2 of Form 8-K filed September 25, 2017).
4.30	Third Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed December 15, 2017).
4.31	Eighteenth Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.2 of Form 8-K filed December 15, 2017).
4.32	Tenth Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp., Sunoco Logistics Partners Operations L.P. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 of Form 8-K filed December 15, 2017).
4.33	Eleventh Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp., Sunoco Logistics Partners Operations L.P. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.4 of Form 8-K filed December 15, 2017).
4.34	Second Supplemental Indenture, dated as of December 1, 2017, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.6 of Form 8-K filed December 6, 2017).
10.1.1+	Second Amended and Restated Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit A to the Registrant's Definitive Proxy Statement on Schedule 14A filed October 24, 2014).
10.1.2+	Energy Transfer Partners, L.P. Amended and Restated 2011 Long Term Incentive Plan (incorporated by reference to Exhibit A to the Definitive Proxy Statement on Schedule 14A filed November 14, 2011 by Regency Energy Partners LP).
10.2+	Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan (incorporated by reference to Exhibit 10.6.6 to the Registrant's Form 10-Q for the quarter ended June 30, 2008).
10.3+	Energy Transfer Partners Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2010).

Exhibit Number	Description
10.4+	Form of Grant Agreement under the Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan and the 2008 Energy Transfer Partners, L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 1, 2004).
10.5+	Energy Transfer Partners, L.L.C. Annual Bonus Plan effective January 1, 2014 (incorporated by reference to Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended June 30, 2014).
10.6	Guarantee of Collection, dated as of April 30, 2013, by and between Regency Energy Partners LP, PEPL Holdings, LLC and Regency Energy Finance Corp. (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed on April 30, 2013).
10.7	Exchange and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and ETE Common Holdings, LLC dated August 7, 2013 (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed on April 28, 2014).
10.8	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed February 1, 2005).
10.9	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 18, 2006).
10.10	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.55 to the Registrant's Form 10-Q for the quarter ended May 31, 2007).
10.10.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.55.1 to the Registrant's Form 10-Q for the quarter ended May 31, 2007).
10.11	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.56 to the Registrant's Form 10-Q for the quarter ended May 31, 2007).
10.11.1	Note Purchase Agreement, dated December 9, 2009, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed December 14, 2009).
10.12	Credit Agreement dated as of December 1, 2017 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, the other lenders party thereto and the other parties named therein (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K, File No. 1-11727, filed December 6, 2017).
10.13	364-Day Credit Agreement dated December 1, 2017 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, the other lenders party thereto and other parties thereto (incorporated by referenced to Exhibit 10.2 to the Registrant's Form 8-K filed December 6, 2017).
10.14	Guaranty dated as of December 1, 2017 by Sunoco Logistics Partners Operations, L.P. and each other Subsidiary from time to time party thereto in favor of Wells Fargo Bank, National Association, as Administrative Agent for the Lenders under that certain Credit Agreement dated as of December 1, 2017 (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K No. 1-31219, filed December 6, 2017).
10.15	Guaranty dated as of December 1, 2017 by Sunoco Logistics Partners Operations, L.P. and each other Subsidiary from time to time party thereto in favor of Wells Fargo Bank, National Association, as Administrative Agent for the Lenders under that certain 364-Day Credit Agreement dated as of December 1, 2017 (incorporated by reference to Exhibit 10.4 to the Registrant's Form 8-K, File No. 1-31219, filed December 6, 2017).
10.16	Guarantee of Collection made as of March 26, 2012, by Citrus ETP Finance LLC, to Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on March 28, 2012).
10.17	Support Agreement, dated March 26, 2012, by and among PEPL Holdings, LLC, Energy Transfer Partners, L.P., and Citrus ETP Finance LLC (incorporated by reference to Exhibit 10.2 to Registrant's Form 8-K filed on March 28, 2012).
10.18	Contingent Residual Support Agreement by and among Energy Transfer Partners, L.P., AmeriGas Finance LLC, AmeriGas Finance Corp., AmeriGas Partners, L.P. and, for certain limited purposes, UGI Corporation, dated January 12, 2012 (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on January 13, 2012).
10.19	Unitholder Agreement by and among Energy Transfer Equity, L.P., Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated January 12, 2012 (incorporated by reference to Exhibit 10.2 to Registrant's Form 8-K filed on January 13, 2012).

Exhibit Number	Description
10.20	Letter agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated January 11, 2012 (incorporated by reference to Exhibit 10.3 to Registrant's Form 8-K filed on January 13, 2012).
10.21	Letter Agreement, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on May 1, 2012).
10.22	Guarantee of Collection, made as of April 1, 2015, by ETP Retail Holdings, LLC to Sunoco LP and Sunoco Finance Corp. (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed on April 1, 2015).
10.23	Support Agreement, made as of April 1, 2015, by and among Sunoco, Inc. (R&M), Sunoco LP, Sunoco Finance Corp. and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed April 1, 2015).
10.24	Support Agreement, made as of April 1, 2015, by and among Atlantic Refining & Marketing Corp., Sunoco LP, Sunoco Finance Corp. and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.4 to the Registrant's Form 8-K filed April 1, 2015).
10.25	Eleventh Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed April 30, 2015).
10.26	Ninth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed April 30, 2015).
10.27	Sixth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Panhandle Eastern Pipe Line Company, LP, as guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed April 30, 2015).
10.28	Eighth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.4 to the Registrant's Form 8-K filed April 30, 2015).
10.29	Second Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.5 to the Registrant's Form 8-K filed April 30, 2015).
10.30	Separation and Non-Solicit Agreement and Full Release of Claims (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed May 14, 2015).
10.31	Seventh Supplemental Indenture, dated as of May 28, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Panhandle Eastern Pipe Line Company, LP, Energy Transfer Partners, L.P., as co-obligor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed June 1, 2015).
10.32	Twelfth Supplemental Indenture, dated as of August 10, 2015, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed August 13, 2015).
10.33	Thirteenth Supplemental Indenture, dated as of December 1, 2017 by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.7 to the Registrant's Form 8-K, File No. 1-31219, filed December 6, 2017).
10.34	Eighth Supplemental Indenture, dated as of August 10, 2015, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed August 13, 2015).
10.35	Ninth Supplemental Indenture, dated as of December 1, 2017 by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.9 to the Registrant's Form 8-K, File No. 1-31219, filed December 6, 2017).
10.36	Ninth Supplemental Indenture, dated as of August 10, 2015, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed August 13, 2015).
10.37	Tenth Supplemental Indenture, dated as of December 1, 2016 by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.10 to the Registrant's Form 8-K, File No. 1-31219, filed December 6, 2017).

Exhibit Number	Description
10.38	Contribution Agreement, dated as of July 14, 2015, by and among Susser Holdings Corporation, Heritage Holdings, Inc., ETP Holdco Corporation, Sunoco LP, Sunoco GP LLC and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed July 15, 2015).
10.39	Exchange and Repurchase Agreement, dated as of July 14, 2015, by and among Energy Transfer Equity, L.P., Energy Transfer Partners GP, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed July 15, 2015).
10.40	Contribution Agreement dated as of November 15, 2015, by and among Sunoco, LLC, Sunoco, Inc., ETP Retail Holdings, LLC, Sunoco LP, Sunoco GP LLC, and solely with respect to Section 11.19 and other provisions related thereto, Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 19, 2015).
10.41	Energy Transfer Partners Deferred Compensation Plan for Former Sunoco Executives effective October 5, 2012 (incorporated by reference to Exhibit 10.21 of the Form 10-K of Sunoco Logistics Partners L.P., File No. 1-31219, filed February 25, 2016).
10.42	Guarantee of Collection, dated as of March 31, 2016, by and between ETP Retail Holdings, LLC and Sunoco LP (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed April 1, 2016).
10.43	Support Agreement, dated as of March 31, 2016, by and between Sunoco, Inc., Sunoco LP, and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed April 1, 2016).
10.44	Support Agreement, dated as of March 31, 2016, by and between Atlantic Refining & Marketing Corp., Sunoco LP, and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed April 1, 2016).
10.45	Form of Commercial Paper Dealer Agreement between Energy Transfer Partners, L.P., as Issuer, and the Dealer party thereto (incorporated by reference to Exhibit 99.1 to the Registrant's Form 8-K filed August 22, 2016).
12.1*	Computation of Ratio of Earnings to Fixed Charges.
12.2*	Computation of Ratio of Earnings to Fixed Charges.
18.1*	Preferability Letter from Grant Thornton LLP.
21.1*	List of Subsidiaries.
23.1*	Consent of Grant Thornton LLP.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2017 and December 31, 2016; (ii) our Consolidated Statements of Operations for the years ended December 31, 2017, 2016 and 2015; (iii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2017, 2016 and 2015; (iv) our Consolidated Statement of Partners' Capital for the years ended December 31, 2017, 2016 and 2015; (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2017, 2016 and 2015; and (vi) the notes to our Consolidated Financial Statements.

* Filed herewith.

** Furnished herewith.

\+ Denotes a management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENERGY TRANSFER PARTNERS, L.P.

By: Energy Transfer Partners GP, L.P,
its general partner.
By: Energy Transfer Partners, L.L.C.,
its general partner

By: /s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer and officer duly authorized to sign on behalf of the registrant

Dated: February 23, 2018

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

Signature	Title	Date
/s/ Kelcy L. Warren Kelcy L. Warren	Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)	February 23, 2018
/s/ Thomas E. Long Thomas E. Long	Chief Financial Officer (Principal Financial Officer)	February 23, 2018
/s/ A. Troy Sturrock A. Troy Sturrock	Senior Vice President and Controller (Principal Accounting Officer)	February 23, 2018
/s/ Matthew S. Ramsey Matthew S. Ramsey	President, Chief Operating Officer and Director	February 23, 2018
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	Chief Commercial Officer and Director	February 23, 2018
/s/ Ray C. Davis Ray C. Davis	Director	February 23, 2018
/s/ Michael K. Grimm Michael K. Grimm	Director	February 23, 2018
/s/ David K. Skidmore David K. Skidmore	Director	February 23, 2018
/s/ W. Brett Smith W. Brett Smith	Director	February 23, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of Energy Transfer Partners, L.L.C. and
Unitholders of Energy Transfer Partners, L.P.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 23, 2018 expressed an unqualified opinion thereon.

Change in accounting principle

As discussed in Note 2 to the consolidated financial statements, the Partnership has changed its method of accounting for certain inventories.

Basis for opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2004.

Dallas, Texas
February 23, 2018

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31,	
	2017	2016*
ASSETS		
Current assets:		
Cash and cash equivalents	$ 306	$ 360
Accounts receivable, net	3,946	3,002
Accounts receivable from related companies	318	209
Inventories	1,589	1,626
Income taxes receivable	135	128
Derivative assets	24	20
Other current assets	210	298
Total current assets	6,528	5,643
Property, plant and equipment	67,699	58,220
Accumulated depreciation and depletion	(9,262)	(7,303)
	58,437	50,917
Advances to and investments in unconsolidated affiliates	3,816	4,280
Other non-current assets, net	758	672
Intangible assets, net	5,311	4,696
Goodwill	3,115	3,897
Total assets	$ 77,965	$ 70,105

* As adjusted. See Note 2.

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31,	
	2017	2016*
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 4,126	$ 2,900
Accounts payable to related companies	209	43
Derivative liabilities	109	166
Accrued and other current liabilities	2,143	1,905
Current maturities of long-term debt	407	1,189
Total current liabilities	6,994	6,203
Long-term debt, less current maturities	32,687	31,741
Long-term notes payable – related company	—	250
Non-current derivative liabilities	145	76
Deferred income taxes	2,883	4,394
Other non-current liabilities	1,084	952
Commitments and contingencies		
Legacy ETP Preferred Units	—	33
Redeemable noncontrolling interests	21	15
Equity:		
Series A Preferred Units (950,000 units authorized, issued and outstanding as of December 31, 2017)	944	—
Series B Preferred Units (550,000 units authorized, issued and outstanding as of December 31, 2017)	547	—
Limited Partners:		
Common Unitholders (1,164,112,575 and 794,803,854 units authorized, issued and outstanding as of December 31, 2017 and 2016, respectively)	26,531	14,925
Class E Unitholder (8,853,832 units authorized, issued and outstanding – held by subsidiary)	—	—
Class G Unitholder (90,706,000 units authorized, issued and outstanding – held by subsidiary)	—	—
Class H Unitholder (81,001,069 units authorized, issued and outstanding as of December 31, 2016)	—	3,480
Class I Unitholder (100 units authorized, issued and outstanding)	—	2
Class K Unitholders (101,525,429 units authorized, issued and outstanding – held by subsidiaries)	—	—
General Partner	244	206
Accumulated other comprehensive income	3	8
Total partners' capital	28,269	18,621
Noncontrolling interest	5,882	7,820
Total equity	34,151	26,441
Total liabilities and equity	$ 77,965	$ 70,105

* As adjusted. See Note 2.

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions, except per unit data)

	Years Ended December 31,		
	2017	2016*	2015*
REVENUES:			
Natural gas sales	$ 4,172	$ 3,619	$ 3,671
NGL sales	6,972	4,841	3,936
Crude sales	10,184	6,766	8,378
Gathering, transportation and other fees	4,265	4,003	3,997
Refined product sales (see Note 3)	1,515	1,047	9,958
Other (see Note 3)	1,946	1,551	4,352
Total revenues	29,054	21,827	34,292
COSTS AND EXPENSES:			
Cost of products sold (see Note 3)	20,801	15,080	26,714
Operating expenses (see Note 3)	2,170	1,839	2,608
Depreciation, depletion and amortization	2,332	1,986	1,929
Selling, general and administrative (see Note 3)	434	348	475
Impairment losses	920	813	339
Total costs and expenses	26,657	20,066	32,065
OPERATING INCOME	2,397	1,761	2,227
OTHER INCOME (EXPENSE):			
Interest expense, net	(1,365)	(1,317)	(1,291)
Equity in earnings from unconsolidated affiliates	156	59	469
Impairment of investments in unconsolidated affiliates	(313)	(308)	—
Gains on acquisitions	—	83	—
Losses on extinguishments of debt	(42)	—	(43)
Losses on interest rate derivatives	(37)	(12)	(18)
Other, net	209	131	22
INCOME BEFORE INCOME TAX BENEFIT	1,005	397	1,366
Income tax benefit	(1,496)	(186)	(123)
NET INCOME	2,501	583	1,489
Less: Net income attributable to noncontrolling interest	420	295	134
Less: Net loss attributable to predecessor	—	—	(34)
NET INCOME ATTRIBUTABLE TO PARTNERS	2,081	288	1,389
General Partner's interest in net income	990	948	1,064
Preferred Unitholders' interest in net income	12	—	—
Class H Unitholder's interest in net income	93	351	258
Class I Unitholder's interest in net income	—	8	94
Common Unitholders' interest in net income (loss)	$ 986	$ (1,019)	$ (27)
NET INCOME (LOSS) PER COMMON UNIT:			
Basic	$ 0.94	$ (1.38)	$ (0.07)
Diluted	$ 0.93	$ (1.38)	$ (0.08)

* As adjusted. See Note 2.

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in millions)

	Years Ended December 31,		
	2017	2016*	2015*
Net income	$ 2,501	$ 583	$ 1,489
Other comprehensive income (loss), net of tax:			
Change in value of available-for-sale securities	6	2	(3)
Actuarial gain (loss) relating to pension and other postretirement benefits	(12)	(1)	65
Foreign currency translation adjustment	—	(1)	(1)
Change in other comprehensive income (loss) from unconsolidated affiliates	1	4	(1)
	(5)	4	60
Comprehensive income	2,496	587	1,549
Less: Comprehensive income attributable to noncontrolling interest	420	295	134
Less: Comprehensive loss attributable to predecessor	—	—	(34)
Comprehensive income attributable to partners	$ 2,076	$ 292	$ 1,449

* As adjusted. See Note 2.

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)

	Series A Preferred Units	Series B Preferred Units	Limited Partners: Common Unit holders	Limited Partners: Class H Units	Limited Partners: Class I Units	General Partner	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Predecessor Equity	Total
Balance, December 31, 2014*	$ —	$ —	$ 10,427	$ 1,512	$ —	$ 184	$ (56)	$ 5,143	$ 8,088	$ 25,298
Distributions to partners	—	—	(1,863)	(247)	(80)	(944)	—	—	—	(3,134)
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(338)	—	(338)
Units issued for cash	—	—	1,428	—	—	—	—	—	—	1,428
Subsidiary units issued for cash	—	—	298	—	—	2	—	1,219	—	1,519
Capital contributions from noncontrolling interest	—	—	—	—	—	—	—	875	—	875
Bakken Pipeline Transaction	—	—	(999)	1,946	—	—	—	72	—	1,019
Sunoco LP Exchange Transaction	—	—	(52)	—	—	—	—	(940)	—	(992)
Susser Exchange Transaction	—	—	(68)	—	—	—	—	—	—	(68)
Acquisition and disposition of noncontrolling interest	—	—	(26)	—	—	—	—	(39)	—	(65)
Predecessor distributions to partners	—	—	—	—	—	—	—	—	(202)	(202)
Predecessor units issued for cash	—	—	—	—	—	—	—	—	34	34
Regency Merger	—	—	7,890	—	—	—	—	—	(7,890)	—
Other comprehensive income, net of tax	—	—	—	—	—	—	60	—	—	60
Other, net	—	—	23	—	—	—	—	36	4	63
Net income (loss)	—	—	(27)	258	94	1,064	—	134	(34)	1,489
Balance, December 31, 2015*	—	—	17,031	3,469	14	306	4	6,162	—	26,986
Distributions to partners	—	—	(2,134)	(340)	(20)	(1,048)	—	—	—	(3,542)
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(481)	—	(481)
Units issued for cash	—	—	1,098	—	—	—	—	—	—	1,098
Subsidiary units issued	—	—	37	—	—	—	—	1,351	—	1,388

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

Capital contributions from noncontrolling interest	—	—	—	—	—	—	—	236	—	236
Sunoco, Inc. retail business to Sunoco LP transaction	—	—	(405)	—	—	—	—	—	—	(405)
PennTex Acquisition	—	—	307	—	—	—	—	236	—	543
Other comprehensive income, net of tax	—	—	—	—	—	—	4	—	—	4
Other, net	—	—	10	—	—	—	—	21	—	31
Net income (loss)	—	—	(1,019)	351	8	948	—	295	—	583
Balance, December 31, 2016*	—	—	14,925	3,480	2	206	8	7,820	—	26,441
Distributions to partners	—	—	(2,419)	(95)	(2)	(952)	—	—	—	(3,468)
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(430)	—	(430)
Units issued for cash	937	542	2,283	—	—	—	—	—	—	3,762
Sunoco Logistics Merger	—	—	9,416	(3,478)	—	—	—	(5,938)	—	—
Capital contributions from noncontrolling interest	—	—	—	—	—	—	—	2,202	—	2,202
Sale of Bakken Pipeline interest	—	—	1,260	—	—	—	—	740	—	2,000
Sale of Rover Pipeline interest	—	—	93	—	—	—	—	1,385	—	1,478
Acquisition of PennTex noncontrolling interest	—	—	(48)	—	—	—	—	(232)	—	(280)
Other comprehensive loss, net of tax	—	—	—	—	—	—	(5)	—	—	(5)
Other, net	—	—	35	—	—	—	—	(85)	—	(50)
Net income	7	5	986	93	—	990	—	420	—	2,501
Balance, December 31, 2017	$ 944	$ 547	$ 26,531	$ —	$ —	$ 244	$ 3	$ 5,882	$ —	$ 34,151

* As adjusted. See Note 2.

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31,		
	2017	2016*	2015*
OPERATING ACTIVITIES:			
Net income	$ 2,501	$ 583	$ 1,489
Reconciliation of net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	2,332	1,986	1,929
Deferred income taxes	(1,531)	(169)	202
Amortization included in interest expense	2	(20)	(36)
Inventory valuation adjustments	—	—	(58)
Unit-based compensation expense	74	80	79
Impairment losses	920	813	339
Gains on acquisitions	—	(83)	—
Losses on extinguishments of debt	42	—	43
Impairment of investments in unconsolidated affiliates	313	308	—
Distributions on unvested awards	(31)	(25)	(16)
Equity in earnings of unconsolidated affiliates	(156)	(59)	(469)
Distributions from unconsolidated affiliates	440	406	440
Other non-cash	(261)	(271)	(22)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	(160)	(246)	(1,173)
Net cash provided by operating activities	4,485	3,303	2,747
INVESTING ACTIVITIES:			
Cash proceeds from sale of Bakken Pipeline interest	2,000	—	—
Cash proceeds from sale of Rover Pipeline interest	1,478	—	—
Proceeds from the Sunoco, Inc. retail business to Sunoco LP transaction	—	2,200	—
Proceeds from Bakken Pipeline Transaction	—	—	980
Proceeds from Susser Exchange Transaction	—	—	967
Proceeds from sale of noncontrolling interest	—	—	64
Cash paid for acquisition of PennTex noncontrolling interest	(280)	—	—
Cash paid for Vitol Acquisition, net of cash received	—	(769)	—
Cash paid for PennTex Acquisition, net of cash received	—	(299)	—
Cash transferred to ETE in connection with the Sunoco LP Exchange	—	—	(114)
Cash paid for acquisition of a noncontrolling interest	—	—	(129)
Cash paid for all other acquisitions	(264)	(159)	(675)
Capital expenditures, excluding allowance for equity funds used during construction	(8,335)	(7,550)	(9,098)
Contributions in aid of construction costs	24	71	80
Contributions to unconsolidated affiliates	(268)	(59)	(45)
Distributions from unconsolidated affiliates in excess of cumulative earnings	136	135	124
Proceeds from the sale of assets	35	25	23
Change in restricted cash	—	14	19
Other	1	1	(16)
Net cash used in investing activities	(5,473)	(6,390)	(7,820)

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

FINANCING ACTIVITIES:			
Proceeds from borrowings	26,736	19,916	22,462
Repayments of long-term debt	(26,494)	(15,799)	(17,843)
Cash (paid to) received from affiliate notes	(255)	124	233
Common Units issued for cash	2,283	1,098	1,428
Preferred Units issued for cash	1,479	—	—
Subsidiary units issued for cash	—	1,388	1,519
Predecessor units issued for cash	—	—	34
Capital contributions from noncontrolling interest	1,214	236	841
Distributions to partners	(3,468)	(3,542)	(3,134)
Predecessor distributions to partners	—	—	(202)
Distributions to noncontrolling interest	(430)	(481)	(338)
Redemption of Legacy ETP Preferred Units	(53)	—	—
Debt issuance costs	(83)	(22)	(63)
Other	5	2	—
Net cash provided by financing activities	934	2,920	4,937
Decrease in cash and cash equivalents	(54)	(167)	(136)
Cash and cash equivalents, beginning of period	360	527	663
Cash and cash equivalents, end of period	$ 306	$ 360	$ 527

* As adjusted. See Note 2.

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar and unit amounts, except per unit data, are in millions)

1. OPERATIONS AND BASIS OF PRESENTATION:

Organization. The consolidated financial statements presented herein contain the results of Energy Transfer Partners, L.P. and its subsidiaries (the "Partnership," "we," "us," "our" or "ETP"). The Partnership is managed by our general partner, ETP GP, which is in turn managed by its general partner, ETP LLC. ETE, a publicly traded master limited partnership, owns ETP LLC, the general partner of our General Partner.

In April 2017, ETP and Sunoco Logistics completed the previously announced merger transaction in which Sunoco Logistics acquired ETP in a unit-for-unit transaction (the "Sunoco Logistics Merger"). Under the terms of the transaction, ETP unitholders received 1.5 common units of Sunoco Logistics for each common unit of ETP they owned. Under the terms of the merger agreement, Sunoco Logistics' general partner was merged with and into ETP GP, with ETP GP surviving as an indirect wholly-owned subsidiary of ETE. In connection with the merger, the ETP Class H units were cancelled. The outstanding ETP Class E units, Class G units, Class I units and Class K units at the effective time of the merger were converted into an equal number of newly created classes of Sunoco Logistics units, with the same rights, preferences, privileges, duties and obligations as such classes of ETP units had immediately prior to the closing of the merger. Additionally, the outstanding Sunoco Logistics common units and Sunoco Logistics Class B units owned by ETP at the effective time of the merger were cancelled.

In connection with the Sunoco Logistics Merger, Energy Transfer Partners, L.P. changed its name from "Energy Transfer Partners, L.P." to "Energy Transfer, LP" and Sunoco Logistics Partners L.P. changed its name to "Energy Transfer Partners, L.P." For purposes of maintaining clarity, the following references are used herein:

- References to "ETLP" refer to Energy Transfer, LP subsequent to the close of the merger;
- References to "Sunoco Logistics" refer to the entity named Sunoco Logistics Partners L.P. prior to the close of the merger; and
- References to "ETP" refer to the consolidated entity named Energy Transfer Partners, L.P. subsequent to the close of the merger.

The Sunoco Logistics Merger resulted in Energy Transfer Partners, L.P. being treated as the surviving consolidated entity from an accounting perspective, while Sunoco Logistics (prior to changing its name to "Energy Transfer Partners, L.P.") was the surviving consolidated entity from a legal and reporting perspective. Therefore, for the pre-merger periods, the consolidated financial statements reflect the consolidated financial statements of the legal acquiree (i.e., the entity that was named "Energy Transfer Partners, L.P." prior to the merger and name changes).

The Sunoco Logistics Merger was accounted for as an equity transaction. The Sunoco Logistics Merger did not result in any changes to the carrying values of assets and liabilities in the consolidated financial statements, and no gain or loss was recognized. For the periods prior to the Sunoco Logistics Merger, the Sunoco Logistics limited partner interests that were owned by third parties (other than Energy Transfer Partners, L.P. or its consolidated subsidiaries) are presented as noncontrolling interest in these consolidated financial statements.

The historical common units and net income (loss) per limited partner unit amounts presented in these consolidated financial statements have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange in connection with the Sunoco Logistics Merger.

The Partnership is engaged in the gathering and processing, compression, treating and transportation of natural gas, focusing on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Utica, Bone Spring and Avalon shales.

The Partnership is engaged in intrastate transportation and storage natural gas operations that own and operate natural gas pipeline systems that are engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico and West Virginia.

The Partnership owns and operates interstate pipelines, either directly or through equity method investments, that transport natural gas to various markets in the United States.

The Partnership owns a controlling interest in Sunoco Logistics Partners Operations L.P., which owns and operates a logistics business, consisting of a geographically diverse portfolio of complementary pipeline, terminalling, and acquisition and marketing assets, which are used to facilitate the purchase and sale of crude oil, NGLs and refined products.

Basis of Presentation. The consolidated financial statements of the Partnership have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year amounts have been conformed to the current year presentation. These reclassifications had no impact on net income or total equity. Management evaluated subsequent events through the date the financial statements were issued.

For prior periods reported herein, certain transactions related to the business of legacy Sunoco Logistics have been reclassified from cost of products sold to operating expenses; these transactions include sales between operating subsidiaries and their marketing affiliates. These reclassifications had no impact on net income or total equity.

The Partnership owns varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, these undivided interests are consolidated proportionately.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Change in Accounting Policy

During the fourth quarter of 2017, the Partnership elected to change its method of inventory costing to weighted-average cost for certain inventory that had previously been accounted for using the last-in, first-out ("LIFO") method. The inventory impacted by this change included the crude oil, refined products and NGLs associated with the legacy Sunoco Logistics business. Management believes that the weighted-average cost method is preferable to the LIFO method as it more closely aligns the accounting policies across the consolidated entity, given that the legacy ETP inventory has been accounted for using the weighted-average cost method.

As a result of this change in accounting policy, prior periods have been retrospectively adjusted, as follows:

	Year Ended December 31, 2016			Year Ended December 31, 2015		
	As Originally Reported*	Effect of Change	As Adjusted	As Originally Reported*	Effect of Change	As Adjusted
Consolidated Statement of Operations and Comprehensive Income:						
Cost of products sold	$ 15,039	$ 41	$ 15,080	$ 26,682	$ 32	$ 26,714
Operating income	1,802	(41)	1,761	2,259	(32)	2,227
Income before income tax benefit	438	(41)	397	1,398	(32)	1,366
Net income	624	(41)	583	1,521	(32)	1,489
Net income attributable to partners	297	(9)	288	1,398	(9)	1,389
Net loss per common unit - basic	(1.37)	(0.01)	(1.38)	(0.06)	(0.01)	(0.07)
Net loss per common unit - diluted	(1.37)	(0.01)	(1.38)	(0.07)	(0.01)	(0.08)
Comprehensive income	628	(41)	587	1,581	(32)	1,549
Comprehensive income attributable to partners	301	(9)	292	1,458	(9)	1,449
Consolidated Statements of Cash Flows:						
Net income	624	(41)	583	1,521	(32)	1,489
Inventory valuation adjustments	(170)	170	—	104	(162)	(58)
Net change in operating assets and liabilities (change in inventories)	(117)	(129)	(246)	(1,367)	194	(1,173)
Consolidated Balance Sheets (at period end):						
Inventories	1,712	(86)	1,626	1,213	(45)	1,168
Total partners' capital	18,642	(21)	18,621	20,836	(12)	20,824

* Amounts reflect certain reclassifications made to conform to the current year presentation.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream, NGL and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the estimated operating results represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Recent Accounting Pronouncements

ASU 2014-09

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle 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. The Partnership adopted ASU 2014-09 on January 1, 2018. The Partnership applied the cumulative catchup transition method and recognized the cumulative effect of the retrospective application of the standard. The effect of the retrospective application of the standard was not material.

For future periods, we expect that the adoption of this standard will result in a change to revenues with offsetting changes to costs associated primarily with the designation of certain of our midstream segment agreements to be in-substance supply agreements, requiring amounts that had previously been reported as revenue under these agreements to be reclassified to a reduction of cost of sales. Changes to revenues along with offsetting changes to costs will also occur due to changes in the accounting for noncash consideration in multiple of our reportable segments, as well as fuel usage and loss allowances. None of these changes is expected to have a material impact on net income.

ASU 2016-02

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, *Leases (Topic 842)* ("ASU 2016-02"), which establishes the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. The Partnership expects to adopt ASU 2016-02 in the first quarter of 2019 and is currently evaluating the impact that adopting this new standard will have on the consolidated financial statements and related disclosures.

ASU 2016-16

On January 1, 2018, the Partnership adopted Accounting Standards Update No. 2016-16, *Income Taxes (Topic 740): Intra-entity Transfers of Assets Other Than Inventory* ("ASU 2016-16"), which requires that entities recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The amendments in this update do not change GAAP for the pre-tax effects of an intra-entity asset transfer under Topic 810, Consolidation, or for an intra-entity transfer of inventory. We do not anticipate a material impact to our financial position or results of operations as a result of the adoption of this standard.

ASU 2017-04

In January 2017, the FASB issued ASU No. 2017-04 "*Intangibles-Goodwill and other (Topic 350): Simplifying the test for goodwill impairment.*" The amendments in this update remove the second step of the two-step test currently required by Topic 350. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance did not amend the optional qualitative assessment of goodwill impairment. The standard requires prospective application and therefore will only impact periods subsequent to the adoption. The Partnership adopted this ASU for its annual goodwill impairment test in the fourth quarter of 2017.

ASU 2017-12

In August 2017, the FASB issued ASU No. 2017-12 "*Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities.*" The amendments in this update improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. In addition, the amendments in this update make certain targeted improvements to simplify the application of the hedge accounting guidance in current GAAP. This ASU is effective for financial statements issued for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. The Partnership is currently evaluating the impact that adopting this new standard will have on the consolidated financial statements and related disclosures.

Revenue Recognition

Revenues for sales of natural gas and NGLs are recognized at the later of the time of delivery of the product to the customer or the time of sale. Revenues from service labor, transportation, treating, compression and gas processing are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available.

Our intrastate transportation and storage and interstate transportation and storage segments' results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) fuel retention based on a percentage of gas transported on the

pipeline, or (iv) a combination of the three, generally payable monthly. Fuel retained for a fee is typically valued at market prices.

Our intrastate transportation and storage segment also generates revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from our marketing operations, and from producers at the wellhead.

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and segment margins principally under fee-based or other arrangements in which we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices, (iv) purchasing all or a specified percentage of natural gas and/or NGL delivered from producers and treating or processing our plant facilities, and (v) making other direct purchases of natural gas and/or NGL at specified delivery points to meet operational or marketing obligations. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

NGL storage and pipeline transportation revenues are recognized when services are performed or products are delivered, respectively. Fractionation and processing revenues are recognized when product is either loaded into a truck or injected into a third-party pipeline, which is when title and risk of loss pass to the customer.

In our natural gas compression business, revenue is recognized for compressor packages and technical service jobs using the completed contract method which recognizes revenue upon completion of the job. Costs incurred on a job are deducted at the time revenue is recognized.

We conduct marketing activities in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

Regulatory Accounting – Regulatory Assets and Liabilities

Our interstate transportation and storage segment is subject to regulation by certain state and federal authorities, and certain subsidiaries in that segment have accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of our regulated entities to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for these entities, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978, it does not currently apply regulatory accounting policies in accounting for its operations. Panhandle does not apply regulatory accounting policies primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

The net change in operating assets and liabilities (net of effects of acquisitions and deconsolidations) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31,		
	2017	2016	2015
Accounts receivable	$ (950)	$ (919)	$ 819
Accounts receivable from related companies	67	30	(243)
Inventories	37	(497)	(157)
Other current assets	39	83	(178)
Other non-current assets, net	(94)	(78)	188
Accounts payable	758	972	(1,215)
Accounts payable to related companies	(3)	29	(160)
Accrued and other current liabilities	(47)	39	(83)
Other non-current liabilities	24	33	(219)
Price risk management assets and liabilities, net	9	62	75
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$ (160)	$ (246)	$ (1,173)

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Years Ended December 31,		
	2017	2016	2015
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 1,059	$ 822	$ 896
Sunoco LP limited partner interest received in exchange for contribution of the Sunoco, Inc. retail business to Sunoco LP	—	194	—
Net gains from subsidiary common unit transactions	—	37	300
NON-CASH FINANCING ACTIVITIES:			
Issuance of Common Units in connection with the PennTex Acquisition	$ —	$ 307	$ —
Issuance of Common Units in connection with the Regency Merger	—	—	9,250
Issuance of Class H Units in connection with the Bakken Pipeline Transaction	—	—	1,946
Contribution of assets from noncontrolling interest	988	—	34
Redemption of Common Units in connection with the Bakken Pipeline Transaction	—	—	999
Redemption of Common Units in connection with the Sunoco LP Exchange	—	—	52
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 1,329	$ 1,411	$ 1,467
Cash paid for (refund of) income taxes	50	(229)	71

Accounts Receivable

Our operations deal with a variety of counterparties across the energy sector, some of which are investment grade, and most of which are not. Internal credit ratings and credit limits are assigned to all counterparties and limits are monitored against credit exposure. Letters of credit or prepayments may be required from those counterparties that are not investment grade depending on the internal credit rating and level of commercial activity with the counterparty.

We have a diverse portfolio of customers; however, because of the midstream and transportation services we provide, many of our customers are engaged in the exploration and production segment. We manage trade credit risk to mitigate credit losses and exposure to uncollectible trade receivables. Prospective and existing customers are reviewed regularly for creditworthiness to manage credit risk within approved tolerances. Customers that do not meet minimum credit standards are required to provide additional credit support in the form of a letter of credit, prepayment, or other forms of security. We establish an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables and considers many factors including historical customer collection experience, general and specific economic trends, and known specific issues related to individual customers, sectors, and transactions that might impact collectability. Increases in the allowance are recorded as a component of operating expenses; reductions in the allowance are recorded when receivables are subsequently collected or written-off. Past due receivable balances are written-off when our efforts have been unsuccessful in collecting the amount due.

We enter into netting arrangements with counterparties to the extent possible to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

Inventories

As discussed under “Change in Accounting Policy” in Note 2, the Partnership changed its accounting policy for certain inventory in the fourth quarter of 2017.

Inventories consist principally of natural gas held in storage, NGLs and refined products, crude oil and spare parts, all of which are valued at the lower of cost or net realizable value utilizing the weighted-average cost method.

Inventories consisted of the following:

	December 31,	
	2017	2016
Natural gas, NGLs, and refined products	$ 733	$ 758
Crude oil	551	651
Spare parts and other	305	217
Total inventories	$ 1,589	$ 1,626

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. Changes in fair value of designated hedged inventory are recorded in inventory on our consolidated balance sheets and cost of products sold in our consolidated statements of operations.

Other Current Assets

Other current assets consisted of the following:

	December 31,	
	2017	2016
Deposits paid to vendors	$ 64	$ 74
Prepaid expenses and other	146	224
Total other current assets	$ 210	$ 298

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or FERC mandated lives of the assets, if applicable. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our consolidated statements of operations.

Property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value.

In 2017, the Partnership recorded a $127 million fixed asset impairment related to Sea Robin primarily due to a reduction in expected future cash flows due to an increase during 2017 in insurance costs related to offshore assets. In 2016, the Partnership recorded a $133 million fixed asset impairment related to the interstate transportation and storage segment primarily due to expected decreases in future cash flows driven by declines in commodity prices as well as a $10 million impairment to property, plant and equipment in the midstream segment. In 2015, the Partnership recorded a $110 million fixed asset impairment related to the NGL and refined products transportation and services segment primarily due to an expected decrease in future cash flows. No other fixed asset impairments were identified or recorded for our reporting units during the periods presented.

Capitalized interest is included for pipeline construction projects, except for certain interstate projects for which an allowance for funds used during construction (“AFUDC”) is accrued. Interest is capitalized based on the current borrowing rate of our revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31,	
	2017	2016
Land and improvements	$ 1,706	$ 676
Buildings and improvements (1 to 45 years)	1,960	1,617
Pipelines and equipment (5 to 83 years)	44,050	36,356
Natural gas and NGL storage facilities (5 to 46 years)	1,681	1,452
Bulk storage, equipment and facilities (2 to 83 years)	3,036	3,701
Vehicles (1 to 25 years)	124	217
Right of way (20 to 83 years)	3,424	3,349
Natural resources	434	434
Other (1 to 40 years)	534	484
Construction work-in-process	10,750	9,934
	67,699	58,220
Less – Accumulated depreciation and depletion	(9,262)	(7,303)
Property, plant and equipment, net	$ 58,437	$ 50,917

We recognized the following amounts for the periods presented:

	Years Ended December 31,		
	2017	2016	2015
Depreciation and depletion expense	$ 2,060	$ 1,793	$ 1,713
Capitalized interest	283	199	163

Advances to and Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee's operating and financial policies. An impairment of an investment in an unconsolidated affiliate is recognized when circumstances indicate that a decline in the investment value is other than temporary.

Other Non-Current Assets, net

Other non-current assets, net are stated at cost less accumulated amortization. Other non-current assets, net consisted of the following:

	December 31,	
	2017	2016
Regulatory assets	$ 85	$ 86
Deferred charges	210	217
Restricted funds	192	190
Long-term affiliated receivable	85	90
Other	186	89
Total other non-current assets, net	$ 758	$ 672

Restricted funds primarily consisted of restricted cash held in our wholly-owned captive insurance companies.

Intangible Assets

Intangible assets are stated at cost, net of amortization computed on the straight-line method. The Partnership removes the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized.

Components and useful lives of intangible assets were as follows:

	December 31, 2017		December 31, 2016	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 6,250	$ (1,003)	$ 5,362	$ (737)
Patents (10 years)	48	(26)	48	(21)
Trade Names (20 years)	66	(25)	66	(22)
Other (5 to 20 years)	1	—	2	(2)
Total intangible assets	$ 6,365	$ (1,054)	$ 5,478	$ (782)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2017	2016	2015
Reported in depreciation, depletion and amortization	$ 272	$ 193	$ 216

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2018	$ 280
2019	278
2020	278
2021	268
2022	256

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate.

In 2015, we recorded $24 million of intangible asset impairments related to the NGL and refined products transportation and services segment primarily due to an expected decrease in future cash flows.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. The annual impairment test is performed during the fourth quarter.

Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation and Storage	Midstream	NGL and Refined Products Transportation and Services	Crude Oil Transportation and Services	All Other	Total
Balance, December 31, 2015	$ 10	$ 912	$ 718	$ 772	$ 912	$ 2,104	$ 5,428
Reduction due to contribution of legacy Sunoco, Inc. retail business	—	—	—	—	—	(1,289)	(1,289)
Acquired	—	—	177	—	251	—	428
Impaired	—	(638)	(32)	—	—	—	(670)
Balance, December 31, 2016	10	274	863	772	1,163	815	3,897
Acquired	—	—	8	—	4	—	12
Impaired	—	(262)	—	(79)	—	(452)	(793)
Other	—	—	(1)	—	—	—	(1)
Balance, December 31, 2017	$ 10	$ 12	$ 870	$ 693	$ 1,167	$ 363	$ 3,115

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized.

During the fourth quarter of 2017, the Partnership performed goodwill impairment tests on our reporting units and recognized goodwill impairments of $262 million in the interstate transportation and storage segment, $79 million in the NGL and refined products transportation and services segment and $452 million in the all other segment primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded.

During the fourth quarter of 2016, the Partnership performed goodwill impairment tests on our reporting units and recognized goodwill impairments of $638 million the interstate transportation and storage segment and $32 million in the midstream segment primarily due to decreases in projected future revenues and cash flows driven by declines in commodity prices and changes in the markets that these assets serve.

During the fourth quarter of 2015, the Partnership performed goodwill impairment tests on our reporting units and recognized goodwill impairments of $99 million in the interstate transportation and storage segment and $106 million in the NGL and refined products transportation and services segment primarily due to market declines in current and expected future commodity prices in the fourth quarter of 2015.

The Partnership determined the fair value of our reporting units using a weighted combination of the discounted cash flow method and the guideline company method. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Such estimates and assumptions include revenue growth rates, operating margins, weighted average costs of capital and future market conditions, among others. The Partnership believes the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. Under the discounted cash flow method, the Partnership determined fair value based on estimated future cash flows of each reporting unit including estimates for capital expenditures, discounted to present value using the risk-adjusted industry rate, which reflect the overall level of inherent risk of the reporting unit. Cash flow projections are derived from one year budgeted amounts and five year operating forecasts plus an estimate of later period cash flows, all of which are evaluated by management. Subsequent period cash flows are developed for each reporting unit using growth rates that management believes are reasonably likely to occur. Under the guideline company method, the Partnership determined the estimated fair value of each of our reporting units by applying valuation multiples of comparable publicly-traded companies to each reporting unit's projected EBITDA and then averaging that estimate with similar historical calculations using a three year average. In addition, the Partnership estimated a reasonable control premium representing the incremental value that accrues to the majority owner from the opportunity to dictate the strategic and operational actions of the business.

Asset Retirement Obligations

We have determined that we are obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of certain assets. The fair value of any ARO is determined based on estimates and assumptions related to retirement costs, which the Partnership bases on historical retirement costs, future inflation rates and credit-adjusted

risk-free interest rates. These fair value assessments are considered to be Level 3 measurements, as they are based on both observable and unobservable inputs. Changes in the liability are recorded for the passage of time (accretion) or for revisions to cash flows originally estimated to settle the ARO.

An ARO is required to be recorded when a legal obligation to retire an asset exists and such obligation can be reasonably estimated. We will record an asset retirement obligation in the periods in which management can reasonably estimate the settlement dates.

Except for certain amounts discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2017 and 2016, in most cases because the settlement dates were indeterminable. Although a number of other onshore assets in Panhandle's system are subject to agreements or regulations that give rise to an ARO upon Panhandle's discontinued use of these assets, AROs were not recorded because these assets have an indeterminate removal or abandonment date given the expected continued use of the assets with proper maintenance or replacement. Sunoco, Inc. has legal asset retirement obligations for several other assets at its previously owned refineries, pipelines and terminals, for which it is not possible to estimate when the obligations will be settled. Consequently, the retirement obligations for these assets cannot be measured at this time. At the end of the useful life of these underlying assets, Sunoco, Inc. is legally or contractually required to abandon in place or remove the asset. We believe we may have additional asset retirement obligations related to its pipeline assets and storage tanks, for which it is not possible to estimate whether or when the retirement obligations will be settled. Consequently, these retirement obligations cannot be measured at this time.

As of December 31, 2017 and 2016, other non-current liabilities in the Partnership's consolidated balance sheets included AROs of $165 million and $170 million, respectively.

Individual component assets have been and will continue to be replaced, but the pipeline and the natural gas gathering and processing systems will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities, management expects supply and demand to exist for the foreseeable future. We have in place a rigorous repair and maintenance program that keeps the pipelines and the natural gas gathering and processing systems in good working order. Therefore, although some of the individual assets may be replaced, the pipelines and the natural gas gathering and processing systems themselves will remain intact indefinitely.

Long-lived assets related to AROs aggregated $2 million and $14 million, and were reflected as property, plant and equipment on our balance sheet as of December 31, 2017 and 2016, respectively. In addition, the Partnership had $21 million and $13 million legally restricted funds for the purpose of settling AROs that was reflected as other non-current assets as of December 31, 2017 and 2016, respectively.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2017	2016
Interest payable	$ 443	$ 440
Customer advances and deposits	59	56
Accrued capital expenditures	1,006	749
Accrued wages and benefits	208	212
Taxes payable other than income taxes	108	63
Exchanges payable	154	208
Other	165	177
Total accrued and other current liabilities	$ 2,143	$ 1,905

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Redeemable Noncontrolling Interests

The noncontrolling interest holders in one of our consolidated subsidiaries has the option to sell its interests to us. In accordance with applicable accounting guidance, the noncontrolling interest is excluded from total equity and reflected as redeemable interest on ETP's consolidated balance sheet.

Environmental Remediation

We accrue environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. Such accruals are undiscounted and are based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. If a range of probable environmental cleanup costs exists for an identified site, the minimum of the range is accrued unless some other point in the range is more likely in which case the most likely amount in the range is accrued.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2017 was $34.28 billion and $33.09 billion, respectively. As of December 31, 2016, the aggregate fair value and carrying amount of our debt obligations was $33.85 billion and $32.93 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

We have commodity derivatives, interest rate derivatives and embedded derivatives in our preferred units that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. During the year ended December 31, 2017, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of December 31, 2017 and 2016 based on inputs used to derive their fair values:

		Fair Value Measurements at December 31, 2017	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 11	$ 11	$ —
Swing Swaps IFERC	13	—	13
Fixed Swaps/Futures	70	70	—
Forward Physical Swaps	8	—	8
Power:			
Forwards	23	—	23
Natural Gas Liquids – Forwards/Swaps	193	193	—
Crude – Futures	2	2	—
Total commodity derivatives	320	276	44
Other non-current assets	21	14	7
Total assets	$ 341	$ 290	$ 51
Liabilities:			
Interest rate derivatives	$ (219)	$ —	$ (219)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(24)	(24)	—
Swing Swaps IFERC	(15)	(1)	(14)
Fixed Swaps/Futures	(57)	(57)	—
Forward Physical Swaps	(2)	—	(2)
Power – Forwards	(22)	—	(22)
Natural Gas Liquids – Forwards/Swaps	(192)	(192)	—
Refined Products – Futures	(25)	(25)	—
Crude – Futures	(1)	(1)	—
Total commodity derivatives	(338)	(300)	(38)
Total liabilities	$ (557)	$ (300)	$ (257)

	Fair Value Measurements at December 31, 2016			
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	$ 14	$ 14	$ —	$ —
Swing Swaps IFERC	2	—	2	—
Fixed Swaps/Futures	96	96	—	—
Forward Physical Swaps	1	—	1	—
Power:				
Forwards	4	—	4	—
Futures	1	1	—	—
Options – Calls	1	1	—	—
Natural Gas Liquids – Forwards/Swaps	233	233	—	—
Refined Products – Futures	1	1	—	—
Crude – Futures	9	9	—	—
Total commodity derivatives	362	355	7	—
Other non-current assets	13	8	5	—
Total assets	$ 375	$ 363	$ 12	$ —
Liabilities:				
Interest rate derivatives	$ (193)	$ —	$ (193)	$ —
Embedded derivatives in the Legacy ETP Preferred Units	(1)	—	—	(1)
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	(11)	(11)	—	—
Swing Swaps IFERC	(3)	—	(3)	—
Fixed Swaps/Futures	(149)	(149)	—	—
Power:				
Forwards	(5)	—	(5)	—
Futures	(1)	(1)	—	—
Natural Gas Liquids – Forwards/Swaps	(273)	(273)	—	—
Refined Products – Futures	(17)	(17)	—	—
Crude – Futures	(13)	(13)	—	—
Total commodity derivatives	(472)	(464)	(8)	—
Total liabilities	$ (666)	$ (464)	$ (201)	$ (1)

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs ("CIAC") are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized.

Shipping and Handling Costs

Shipping and handling costs are included in cost of products sold, except for shipping and handling costs related to fuel consumed for compression and treating which are included in operating expenses.

Costs and Expenses

Cost of products sold include actual cost of fuel sold, adjusted for the effects of our hedging and other commodity derivative activities, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, purchasing costs and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis except for our all other segment in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and costs and expenses in the consolidated statements of operations, with no effect on net income (loss). For the year ended December 31, 2015, excise taxes collected by Sunoco LP were $1.85 billion. The Partnership deconsolidated Sunoco LP effective July 1, 2015 and no excise taxes were collected by our consolidated operations subsequent to that date.

Issuances of Subsidiary Units

We record changes in our ownership interest of our subsidiaries as equity transactions, with no gain or loss recognized in consolidated net income or comprehensive income. For example, upon our subsidiary's issuance of common units in a public offering, we record any difference between the amount of consideration received or paid and the amount by which the noncontrolling interest is adjusted as a change in partners' capital.

Income Taxes

ETP is a publicly traded limited partnership and is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and most state purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial basis of assets and liabilities, differences between the tax accounting and financial accounting treatment of certain items, and due to allocation requirements related to taxable income under our Second Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement").

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and IRS pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, ETP would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2017, 2016, and 2015, our qualifying income met the statutory requirement.

The Partnership conducts certain activities through corporate subsidiaries which are subject to federal, state and local income taxes. These corporate subsidiaries include ETP Holdco, Inland Corporation, Oasis Pipeline Company and until July 31, 2015, Susser Holding Corporation. The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third-party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a commodity hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statements of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statements of operations.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, the change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in "Gains (losses) on interest rate derivatives" in the consolidated statements of operations.

Unit-Based Compensation

For awards of restricted units, we recognize compensation expense over the vesting period based on the grant-date fair value, which is determined based on the market price of our Common Units on the grant date. For awards of cash restricted units, we remeasure the fair value of the award at the end of each reporting period based on the market price of our Common Units as of the reporting date, and the fair value is recorded in other non-current liabilities on our consolidated balance sheets.

Pensions and Other Postretirement Benefit Plans

The Partnership recognizes the overfunded or underfunded status of defined benefit pension and other postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Changes in the funded status of the plan are recorded in the year in which the change occurs within AOCI in equity or, for entities applying regulatory accounting, as a regulatory asset or regulatory liability.

Allocation of Income

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests. The capital account provisions of our Partnership Agreement incorporate principles established for United States Federal income tax purposes and are not comparable to the partners' capital balances reflected under GAAP in our consolidated financial statements. Our net income for partners' capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the IDRs pursuant to our Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2018 Transactions

CDM Contribution Agreement

In January 2018, ETP entered into a contribution agreement ("CDM Contribution Agreement") with ETP GP, ETC Compression, LLC, USAC and ETE, pursuant to which, among other things, ETP will contribute to USAC and USAC will acquire from ETP all of the issued and outstanding membership interests of CDM and CDM E&T for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 common units representing limited partner interests in USAC ("USAC Common Units"), with a value of approximately $335 million, (ii) 6,397,965 units of a newly authorized and established class of units representing limited partner interests in USAC ("Class B Units"), with a value of approximately $112 million and (iii) an amount in cash equal to $1.225 billion, subject to certain adjustments. The Class B Units that ETP will receive will be a new class of partnership interests of USAC that will have substantially all of the rights and obligations of a USAC Common Unit, except the Class B Units will not participate in distributions made prior to the one year anniversary of the closing date of the CDM Contribution Agreement (such date, the "Class B Conversion Date") with respect to USAC Common Units. On the Class B Conversion Date, each Class B Unit will automatically convert into one USAC Common Unit. The transaction is expected to close in the first half of 2018, subject to customary closing conditions.

In connection with the CDM Contribution Agreement, ETP entered into a purchase agreement with ETE, Energy Transfer Partners, L.L.C. (together with ETE, the "GP Purchasers"), USAC Holdings and, solely for certain purposes therein, R/C IV USACP Holdings, L.P., pursuant to which, among other things, the GP Purchasers will acquire from USAC Holdings (i) all of the outstanding limited liability company interests in USA Compression GP, LLC, the general partner of USAC ("USAC GP"), and (ii) 12,466,912 USAC Common Units for cash consideration equal to $250 million.

2017 Transactions

Rover Contribution Agreement

In October 2017, ETP completed the previously announced contribution transaction with a fund managed by Blackstone Energy Partners and Blackstone Capital Partners, pursuant to which ETP exchanged a 49.9% interest in the holding company that owns 65% of the Rover pipeline ("Rover Holdco"). As a result, Rover Holdco is now owned 50.1% by ETP and 49.9% by Blackstone. Upon closing, Blackstone contributed funds to reimburse ETP for its pro rata share of the Rover construction costs incurred by ETP through the closing date, along with the payment of additional amounts subject to certain adjustments.

ETP and Sunoco Logistics Merger

As discussed in Note 1, in April 2017, Energy Transfer Partners, L.P. and Sunoco Logistics completed the Sunoco Logistics Merger.

Permian Express Partners

In February 2017, Sunoco Logistics formed PEP, a strategic joint venture with ExxonMobil. Sunoco Logistics contributed its Permian Express 1, Permian Express 2, Permian Longview and Louisiana Access pipelines. ExxonMobil contributed its Longview to Louisiana and Pegasus pipelines, Hawkins gathering system, an idle pipeline in southern Oklahoma, and its Patoka, Illinois terminal. Assets contributed to PEP by ExxonMobil were reflected at fair value on the Partnership's consolidated balance sheet at the date of the contribution, including $547 million of intangible assets and $435 million of property, plant and equipment.

In July 2017, ETP contributed an approximate 15% ownership interest in Dakota Access and ETCO to PEP, which resulted in an increase in ETP's ownership interest in PEP to approximately 88%. ETP maintains a controlling financial and voting interest in PEP and is the operator of all of the assets. As such, PEP is reflected as a consolidated subsidiary of the Partnership. ExxonMobil's interest in PEP is reflected as noncontrolling interest in the consolidated balance sheets. ExxonMobil's contribution resulted in an increase of $988 million in noncontrolling interest, which is reflected in "Capital contributions from noncontrolling interest" in the consolidated statement of equity.

Bakken Equity Sale

In February 2017, Bakken Holdings Company LLC, an entity in which ETP indirectly owns a 100% membership interest, sold a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by MPLX LP and Enbridge Energy Partners, L.P., for $2.00 billion in cash. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access and ETCO. The remaining 25% of each of Dakota Access and

ETCO is owned by wholly-owned subsidiaries of Phillips 66. ETP continues to consolidate Dakota Access and ETCO subsequent to this transaction.

2016 Transactions

PennTex Acquisition

On November 1, 2016, ETP acquired certain interests in PennTex from various parties for total consideration of approximately $627 million in ETP units and cash. Through this transaction, ETP acquired a controlling financial interest in PennTex, whose assets complement ETP's existing midstream footprint in northern Louisiana. As discussed in Note 8, the Partnership purchased PennTex's remaining outstanding common units in June 2017.

Summary of Assets Acquired and Liabilities Assumed

We accounted for the PennTex acquisition using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date.

The total purchase price was allocated as follows:

	At November 1, 2016
Total current assets	$ 34
Property, plant and equipment	393
Goodwill[1]	177
Intangible assets	446
	1,050
Total current liabilities	6
Long-term debt, less current maturities	164
Other non-current liabilities	17
Noncontrolling interest	236
	423
Total consideration	627
Cash received	21
Total consideration, net of cash received	$ 606

(1) None of the goodwill is expected to be deductible for tax purposes.

The fair values of the assets acquired and liabilities assumed were determined using various valuation techniques, including the income and market approaches.

Sunoco Logistics' Vitol Acquisition

In November 2016, Sunoco Logistics completed an acquisition from Vitol, Inc. ("Vitol") of an integrated crude oil business in West Texas for $760 million plus working capital. The acquisition provides Sunoco Logistics with an approximately 2 million barrel crude oil terminal in Midland, Texas, a crude oil gathering and mainline pipeline system in the Midland Basin, including a significant acreage dedication from an investment-grade Permian producer, and crude oil inventories related to Vitol's crude oil purchasing and marketing business in West Texas. The acquisition also included the purchase of a 50% interest in SunVit Pipeline LLC ("SunVit"), which increased Sunoco Logistics' overall ownership of SunVit to 100%. The $769 million purchase price, net of cash received, consisted primarily of net working capital of $13 million largely attributable to inventory and receivables; property, plant and equipment of $286 million primarily related to pipeline and terminalling assets; intangible assets of $313 million attributable to customer relationships; and goodwill of $251 million.

Bakken Financing

In August 2016, ETP, Sunoco Logistics and Phillips 66 announced the completion of the project-level financing of the Bakken Pipeline. The $2.50 billion credit facility provided substantially all of the remaining capital necessary to complete the projects. As of December 31, 2017, $2.50 billion was outstanding under this credit facility.

Bayou Bridge

In April 2016, Bayou Bridge Pipeline, LLC ("Bayou Bridge"), a joint venture among ETP, Sunoco Logistics and Phillips 66, began commercial operations on the 30-inch segment of the pipeline from Nederland, Texas to Lake Charles, Louisiana. ETP and Sunoco Logistics each hold a 30% interest in the entity and Sunoco Logistics is the operator of the system.

Sunoco Retail to Sunoco LP

In March 2016, ETP contributed to Sunoco LP its remaining 68.42% interest in Sunoco, LLC and 100% interest in the legacy Sunoco, Inc. retail business for $2.23 billion. Sunoco LP paid $2.20 billion in cash, including a working capital adjustment and issued 5.7 million Sunoco LP common units to Retail Holdings, a wholly-owned subsidiary of the Partnership. The transaction was effective January 1, 2016. In connection with this transaction, the Partnership deconsolidated the legacy Sunoco, Inc. retail business, including goodwill of $1.29 billion and intangible assets of $294 million. The results of Sunoco, LLC and the legacy Sunoco, Inc. retail business' operations have not been presented as discontinued operations and Sunoco, Inc.'s retail business assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements.

Following is a summary of amounts reflected for the prior periods in ETP's consolidated statements of operations related to Sunoco, LLC and the legacy Sunoco, Inc. retail business, which operations are no longer consolidated:

	Year Ended December 31, 2015
Revenues	$ 12,482
Cost of products sold	11,174
Operating expenses	798
Selling, general and administrative expenses	106

2015 Transactions

Sunoco LP

In April 2015, Sunoco LP acquired a 31.58% equity interest in Sunoco, LLC from Retail Holdings for $816 million. Sunoco, LLC distributes approximately 5.3 billion gallons per year of motor fuel to customers in the east, midwest and southwest regions of the United States. Sunoco LP paid $775 million in cash and issued a value of $41 million in Sunoco LP common units to Retail Holdings, based on the five-day volume weighted average price of Sunoco LP's common units as of March 20, 2015.

In July 2015, in exchange for the contribution of 100% of Susser from ETP to Sunoco LP, Sunoco LP paid $970 million in cash and issued to ETP subsidiaries 22 million Sunoco LP Class B units valued at $970 million. The Sunoco Class B units did not receive second quarter 2015 cash distributions from Sunoco LP and converted on a one-for-one basis into Sunoco LP common units on the day immediately following the record date for Sunoco LP's second quarter 2015 distribution. In addition, (i) a Susser subsidiary exchanged its 79,308 Sunoco LP common units for 79,308 Sunoco LP Class A units, (ii) 10.9 million Sunoco LP subordinated units owned by Susser subsidiaries were converted into 10.9 million Sunoco LP Class A units and (iii) Sunoco LP issued 79,308 Sunoco LP common units and 10.9 million Sunoco LP subordinated units to subsidiaries of ETP. The Sunoco LP Class A units owned by the Susser subsidiaries were contributed to Sunoco LP as part of the transaction. Sunoco LP subsequently contributed its interests in Susser to one of its subsidiaries.

Effective July 1, 2015, ETE acquired 100% of the membership interests of Sunoco GP, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from ETP, and in exchange, ETP repurchased from ETE 31.5 million ETP common units owned by ETE (the "Sunoco LP Exchange"). In connection with ETP's 2014 acquisition of Susser, ETE agreed to provide ETP a $35 million annual IDR subsidy for 10 years, which terminated upon the closing of ETE's acquisition of Sunoco GP. In connection with the exchange and repurchase, ETE provided ETP a $35 million annual IDR subsidy for two years beginning with the quarter ended September 30, 2015. In connection with this transaction, the Partnership deconsolidated Sunoco LP, including goodwill of $1.81 billion and intangible assets of $982 million related to Sunoco LP. At December 31, 2017, the Partnership held 37.8 million Sunoco LP common units accounted for under the equity method. Subsequent to Sunoco LP's repurchase of a portion of its common units on February 7, 2018, as discussed in Note 4, our investment in Sunoco LP consists of 26.2 million units. The results of Sunoco LP's operations have not been presented as discontinued operations and Sunoco LP's assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements.

Bakken Pipeline

In March 2015, ETE transferred 46.2 million Partnership common units, ETE's 45% interest in the Bakken Pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitled ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the "Bakken Pipeline Transaction"). In connection with this transaction, the Partnership also issued to ETE 100 Class I Units that provided distributions to ETE to offset IDR subsidies previously provided to ETP. These IDR subsidies, including the impact from distributions on Class I Units, were reduced by $55 million in 2015 and $30 million in 2016. The Class H Units were cancelled in connection with the Sunoco Logistics Merger in April 2017.

In October 2015, Sunoco Logistics completed the acquisition of a 40% membership interest (the "Bakken Membership Interest") in Bakken Holdings Company LLC ("Bakken Holdco"). Bakken Holdco, through its wholly-owned subsidiaries, owns a 75% membership interest in each of Dakota Access and ETCO, which together intend to develop the Bakken Pipeline system to deliver crude oil from the Bakken/Three Forks production area in North Dakota to the Gulf Coast. ETP transferred the Bakken Membership Interest to Sunoco Logistics in exchange for approximately 9.4 million Class B Units representing limited partner interests in Sunoco Logistics and the payment by Sunoco Logistics to ETP of $382 million of cash, which represented reimbursement for its proportionate share of the total cash contributions made in the Bakken Pipeline project as of the date of closing of the exchange transaction.

Regency Merger

On April 30, 2015, a wholly-owned subsidiary of the Partnership merged with Regency, with Regency surviving as a wholly-owned subsidiary of the Partnership (the "Regency Merger"). Each Regency common unit and Class F unit was converted into the right to receive 0.6186 Partnership common units. ETP issued 258.3 million Partnership common units to Regency unitholders, including 23.3 million units issued to Partnership subsidiaries. Regency's 1.9 million outstanding Series A Convertible Preferred Units were converted into corresponding Legacy ETP Preferred Units on a one-for-one basis.

In connection with the Regency Merger, ETE agreed to reduce the incentive distributions it receives from the Partnership by a total of $320 million over a five-year period. The IDR subsidy was $80 million for the year ended December 31, 2015 and will total $60 million per year for the following four years.

The Regency Merger was a combination of entities under common control; therefore, Regency's assets and liabilities were not adjusted. The Partnership's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date ETE acquired Regency's general partner). Predecessor equity included on the consolidated financial statements represents Regency's equity prior to the Regency Merger.

ETP has assumed all of the obligations of Regency and Regency Energy Finance Corp., of which ETP was previously a co-obligor or parent guarantor.

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Citrus

ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of KMI. Citrus owns 100% of FGT, an approximately 5,360-mile natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula. Our investment in Citrus is reflected in our interstate transportation and storage segment.

FEP

We have a 50% interest in FEP which owns an approximately 185-mile natural gas pipeline that originates in Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. Our investment in FEP is reflected in the interstate transportation and storage segment. The Partnership evaluated its investment in FEP for impairment as of December 31, 2017, based on FASB Accounting Standards Codification 323, *Investments - Equity Method and Joint Ventures*. The Partnership recorded an impairment of its investment in FEP of $141 million during the year ended December 31, 2017 due to a negative outlook for long-term transportation contracts as a result of a decrease in production in the Fayetteville basin and a customer re-contracting with a competitor.

MEP

We own a 50% interest in MEP, which owns approximately 500 miles of natural gas pipeline that extends from Southeast Oklahoma, across Northeast Texas, Northern Louisiana and Central Mississippi to an interconnect with the Transcontinental natural gas pipeline system in Butler, Alabama. Our investment in MEP is reflected in the interstate transportation and storage segment. The Partnership evaluated its investment in MEP for impairment as of September 30, 2016, based on FASB Accounting Standards Codification 323, *Investments - Equity Method and Joint Ventures*. Based on commercial discussions with current and potential shippers on MEP regarding the outlook for long-term transportation contract rates, the Partnership concluded that the fair value of its investment was other than temporarily impaired, resulting in a non-cash impairment of $308 million during the year ended December 31, 2016.

HPC

We own a 49.99% interest in HPC, which, through its ownership of RIGS, delivers natural gas from northwest Louisiana to downstream pipelines and markets through a 450-mile intrastate pipeline system. Our investment in HPC is reflected in the intrastate transportation and storage segment. The Partnership evaluated its investment in HPC for impairment as of December 31, 2017, based on FASB Accounting Standards Codification 323, *Investments - Equity Method and Joint Ventures*. During the year ended December 31, 2017, the Partnership recorded a $172 million impairment of its equity method investment in HPC primarily due to a decrease in projected future revenues and cash flows driven by the bankruptcy of one of HPC's major customers in 2017 and an expectation that contracts expiring in the next few years will be renewed at lower tariff rates and lower volumes.

Sunoco LP

Effective July 1, 2015, ETE acquired 100% of the membership interests of Sunoco GP, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from the Partnership. As a result, the Partnership deconsolidated Sunoco LP, and its remaining investment in Sunoco LP is accounted for under the equity method. As of December 31, 2017, the Partnership's interest in Sunoco LP common units consisted of 43.5 million units, representing 43.6% of Sunoco LP's total outstanding common units, and is reflected in the all other segment.

In February 2018, after the record date for Sunoco LP's fourth quarter 2017 cash distributions, Sunoco LP repurchased 17,286,859 Sunoco LP common units owned by ETP for aggregate cash consideration of approximately $540 million. ETP used the proceeds from the sale of the Sunoco LP common units to repay amounts outstanding under its revolving credit facility.

The carrying values of the Partnership's advances to and investments in unconsolidated affiliates as of December 31, 2017 and 2016 were as follows:

	December 31,	
	2017	2016
Citrus	$ 1,754	$ 1,729
FEP	121	101
MEP	242	318
HPC	28	382
Sunoco LP	1,095	1,225
Others	576	525
Total	$ 3,816	$ 4,280

The following table presents equity in earnings (losses) of unconsolidated affiliates:

	Years Ended December 31,		
	2017	2016	2015
Citrus	$ 144	$ 102	$ 97
FEP	53	51	55
MEP	38	40	45
HPC[1]	(168)	31	32
Sunoco, LLC	—	—	(10)
Sunoco LP[2]	12	(211)	202
Other	77	46	48
Total equity in earnings of unconsolidated affiliates	156	59	469

(1) For the year ended December 31, 2017, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by HPC, which reduced the Partnership's equity in earnings by $185 million.

(2) For the years ended December 31, 2017 and 2016, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by Sunoco LP, which reduced the Partnership's equity in earnings by $176 million and $277 million, respectively.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, Citrus, FEP, MEP, HPC and Sunoco LP (on a 100% basis) for all periods presented:

	December 31,	
	2017	2016
Current assets	$ 4,750	$ 1,532
Property, plant and equipment, net	9,893	10,310
Other assets	2,286	5,980
Total assets	$ 16,929	$ 17,822
Current liabilities	$ 2,075	$ 1,918
Non-current liabilities	9,375	10,343
Equity	5,479	5,561
Total liabilities and equity	$ 16,929	$ 17,822

	Years Ended December 31,		
	2017	2016	2015
Revenue	$ 13,081	$ 11,150	$ 13,815
Operating income	636	859	1,052
Net income (loss)	294	(22)	664

In addition to the equity method investments described above we have other equity method investments which are not significant to our consolidated financial statements.

5. NET INCOME (LOSS) PER LIMITED PARTNER UNIT:

The following table provides a reconciliation of the numerator and denominator of the basic and diluted income (loss) per unit.

The historical common units and net income (loss) per limited partner unit amounts presented in these consolidated financial statements have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange in connection with the Sunoco Logistics Merger.

	Years Ended December 31,		
	2017	2016	2015
Net income	$ 2,501	$ 583	$ 1,489
Less: Income attributable to noncontrolling interest	420	295	134
Less: Loss attributable to predecessor	—	—	(34)
Net income, net of noncontrolling interest	2,081	288	1,389
General Partner's interest in net income	990	948	1,064
Preferred Unitholders' interest in net income	12	—	—
Class H Unitholder's interest in net income	93	351	258
Class I Unitholder's interest in net income	—	8	94
Common Unitholders' interest in net income (loss)	986	(1,019)	(27)
Additional earnings allocated from (to) General Partner	9	(10)	(5)
Distributions on employee unit awards, net of allocation to General Partner	(27)	(19)	(16)
Net income (loss) available to Common Unitholders	$ 968	$ (1,048)	$ (48)
Weighted average Common Units – basic	1,032.7	758.2	649.2
Basic net income (loss) per Common Unit	$ 0.94	$ (1.38)	$ (0.07)
Income (loss) available to Common Unitholders	$ 968	$ (1,048)	$ (48)
Loss attributable to Legacy ETP Preferred Units	—	—	(6)
Diluted income (loss) available to Common Unitholders	$ 968	$ (1,048)	$ (54)
Weighted average Common Units – basic	1,032.7	758.2	649.2
Dilutive effect of unvested Unit Awards	5.1	—	—
Dilutive effect of Legacy ETP Preferred Units	—	—	1.0
Weighted average Common Units – diluted	1,037.8	758.2	650.2
Diluted income (loss) per Common Unit	$ 0.93	$ (1.38)	$ (0.08)

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2017	2016
ETP Debt		
6.125% Senior Notes due February 15, 2017	$ —	$ 400
2.50% Senior Notes due June 15, 2018 [1]	650	650
6.70% Senior Notes due July 1, 2018 [1]	600	600
9.70% Senior Notes due March 15, 2019	400	400
9.00% Senior Notes due April 15, 2019	450	450
5.50% Senior Notes due February 15, 2020	250	250
5.75% Senior Notes due September 1, 2020	400	400
4.15% Senior Notes due October 1, 2020	1,050	1,050

4.40% Senior Notes due April 1, 2021	600	600
6.50% Senior Notes due July 15, 2021	—	500
4.65% Senior Notes due June 1, 2021	800	800
5.20% Senior Notes due February 1, 2022	1,000	1,000
4.65% Senior Notes due February 15, 2022	300	300
5.875% Senior Notes due March 1, 2022	900	900
5.00% Senior Notes due October 1, 2022	700	700
3.45% Senior Notes due January 15, 2023	350	350
3.60% Senior Notes due February 1, 2023	800	800
5.50% Senior Notes due April 15, 2023	—	700
4.50% Senior Notes due November 1, 2023	600	600
4.90% Senior Notes due February 1, 2024	350	350
7.60% Senior Notes due February 1, 2024	277	277
4.25% Senior Notes due April 1, 2024	500	500
9.00% Debentures due November 1, 2024	65	65
4.05% Senior Notes due March 15, 2025	1,000	1,000
5.95% Senior Notes due December 1, 2025	400	400
4.75% Senior Notes due January 15, 2026	1,000	1,000
3.90% Senior Notes due July 15, 2026	550	550
4.20% Senior Notes due April 15, 2027	600	—
4.00% Senior Notes due October 1, 2027	750	—
8.25% Senior Notes due November 15, 2029	267	267
4.90% Senior Notes due March 15, 2035	500	500
6.625% Senior Notes due October 15, 2036	400	400
7.50% Senior Notes due July 1, 2038	550	550
6.85% Senior Notes due February 15, 2040	250	250
6.05% Senior Notes due June 1, 2041	700	700
6.50% Senior Notes due February 1, 2042	1,000	1,000
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	350
5.15% Senior Notes due February 1, 2043	450	450
5.95% Senior Notes due October 1, 2043	450	450
5.30% Senior Notes due April 1, 2044	700	700
5.15% Senior Notes due March 15, 2045	1,000	1,000
5.35% Senior Notes due May 15, 2045	800	800
6.125% Senior Notes due December 15, 2045	1,000	1,000
5.30% Senior Notes due April 15, 2047	900	—
5.40% Senior Notes due October 1, 2047	1,500	—
Floating Rate Junior Subordinated Notes due November 1, 2066	546	546
ETP $4.0 billion Revolving Credit Facility due December 2022	2,292	—
ETP $1.0 billion 364-Day Credit Facility due November 2018 [2]	50	—
ETLP $3.75 billion Revolving Credit Facility due November 2019	—	2,777
Legacy Sunoco Logistics $2.50 billion Revolving Credit Facility due March 2020	—	1,292
Legacy Sunoco Logistics $1.0 billion 364-Day Credit Facility due December 2017	—	630
Unamortized premiums, discounts and fair value adjustments, net	33	66
Deferred debt issuance costs	(170)	(166)
	29,210	29,454
Transwestern Debt		
5.64% Senior Notes due May 24, 2017	—	82
5.36% Senior Notes due December 9, 2020	175	175
5.89% Senior Notes due May 24, 2022	150	150
5.66% Senior Notes due December 9, 2024	175	175
6.16% Senior Notes due May 24, 2037	75	75
Deferred debt issuance costs	(1)	(1)
	574	656
Panhandle Debt		

6.20% Senior Notes due November 1, 2017	—	300
7.00% Senior Notes due June 15, 2018	400	400

8.125% Senior Notes due June 1, 2019	150	150
7.60% Senior Notes due February 1, 2024	82	82
7.00% Senior Notes due July 15, 2029	66	66
8.25% Senior Notes due November 15, 2029	33	33
Floating Rate Junior Subordinated Notes due November 1, 2066	54	54
Unamortized premiums, discounts and fair value adjustments, net	28	50
	813	1,135
Sunoco, Inc. Debt		
5.75% Senior Notes due January 15, 2017	—	400
Bakken Project Debt		
Bakken Project $2.50 billion Credit Facility due August 2019	2,500	1,100
Deferred debt issuance costs	(8)	(13)
	2,492	1,087
PennTex Debt		
PennTex $275 million Revolving Credit Facility due December 2019	—	168
Other	5	30
Total debt	33,094	32,930
Less: Current maturities of long-term debt	407	1,189
Long-term debt, less current maturities	$ 32,687	$ 31,741

(1) As of December 31, 2017 management had the intent and ability to refinance the $650 million 2.50% senior notes due June 15, 2018 and the $600 million 6.70% senior notes due July 1, 2018, and therefore neither was classified as current.

(2) Borrowings under 364-day credit facilities were classified as long-term debt based on the Partnership's ability and intent to refinance such borrowings on a long-term basis.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $118 million in unamortized net premiums, fair value adjustments and deferred debt issuance costs:

2018	$ 1,700
2019	3,500
2020	1,875
2021	1,400
2022	5,346
Thereafter	19,391
Total	$ 33,212

Long-term debt reflected on our consolidated balance sheets includes fair value adjustments related to interest rate swaps, which represent fair value adjustments that had been recorded in connection with fair value hedge accounting prior to the termination of the interest rate swap.

ETP Senior Notes

The ETP senior notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETP senior notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP senior notes. The balance is payable upon maturity. Interest on the ETP senior notes is paid semi-annually.

The ETP senior notes are unsecured obligations of the Partnership and as a result, the ETP senior notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP senior notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

Transwestern Senior Notes

The Transwestern senior notes are redeemable at any time in whole or pro rata, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is paid semi-annually.

Panhandle Junior Subordinated Notes

The interest rate on the remaining portion of Panhandle's junior subordinated notes due 2066 is a variable rate based upon the three-month LIBOR rate plus 3.0175%. The balance of the variable rate portion of the junior subordinated notes was $54 million at an effective interest rate of 4.39% at December 31, 2017.

Credit Facilities and Commercial Paper

ETP Credit Facilities

On December 1, 2017 the Partnership entered into a five-year, $4.0 billion unsecured revolving credit facility, which matures December 1, 2022 (the "ETP Five-Year Facility") and a $1.0 billion 364-day revolving credit facility that matures on November 30, 2018 (the "ETP 364-Day Facility") (collectively, the "ETP Credit Facilities"). The ETP Five-Year Facility contains an accordion feature, under which the total aggregate commitments may be increased up to $6.0 billion under certain conditions. We use the ETP Credit Facilities to provide temporary financing for our growth projects, as well as for general partnership purposes.

As of December 31, 2017, the ETP Five-Year Facility had $2.29 billion outstanding, of which $2.01 billion was commercial paper. The amount available for future borrowings was $1.56 billion after taking into account letters of credit of $150 million. The weighted average interest rate on the total amount outstanding as of December 31, 2017 was 2.48%.

As of December 31, 2017, the ETP 364-Day Facility had $50 million outstanding, and the amount available for future borrowings was $950 million. The weighted average interest rate on the total amount outstanding as of December 31, 2017 was 5.00%.

ETLP Credit Facility

The ETLP Credit Facility allowed for borrowings of up to $3.75 billion and was used to provide temporary financing for our growth projects, as well as for general partnership purposes. This facility was repaid and terminated concurrent with the establishment of the ETP Credit Facilities on December 1, 2017.

Sunoco Logistics Credit Facilities

ETP maintained a $2.50 billion unsecured revolving credit agreement (the "Sunoco Logistics Credit Facility"). This facility was repaid and terminated concurrent with the establishment of the ETP Credit Facilities on December 1, 2017.

In December 2016, Sunoco Logistics entered into an agreement for a 364-day maturity credit facility ("364-Day Credit Facility"), due to mature on the earlier of the occurrence of the Sunoco Logistics Merger or in December 2017, with a total lending capacity of $1.00 billion. In connection with the Sunoco Logistics Merger, the 364-Day Credit Facility was terminated and repaid in May 2017.

Bakken Credit Facility

In August 2016, Energy Transfer Partners, L.P., Sunoco Logistics and Phillips 66 completed project-level financing of the Bakken Pipeline. The $2.50 billion credit facility is anticipated to provide substantially all of the remaining capital necessary to complete the projects and matures in August 2019 (the "Bakken Credit Facility"). As of December 31, 2017, the Bakken Credit Facility had $2.50 billion of outstanding borrowings. The weighted average interest rate on the total amount outstanding as of December 31, 2017 was 3.00%.

PennTex Revolving Credit Facility

PennTex previously maintained a $275 million revolving credit commitment (the "PennTex Revolving Credit Facility"). In August 2017, the PennTex Revolving Credit Facility was repaid and terminated.

Covenants Related to Our Credit Agreements

Covenants Related to ETP

The agreements relating to the ETP senior notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions.

The ETP Credit Facilities contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries' ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in the ETP Credit Facilities) during certain Defaults (as defined in the ETP Credit Facilities) and during any Event of Default (as defined in the ETP Credit Facilities);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates; and
- enter into restrictive agreements.

The ETP Credit Facilities applicable margin and rate used in connection with the interest rates and commitment fees, respectively, are based on the credit ratings assigned to our senior, unsecured, non-credit enhanced long-term debt. The applicable margin for eurodollar rate loans under the ETP Five-Year Facility ranges from 1.125% to 2.000% and the applicable margin for base rate loans ranges from 0.125% to 1.000%. The applicable rate for commitment fees under the ETP Five-Year Facility ranges from 0.125% to 0.300%. The applicable margin for eurodollar rate loans under the ETP 364-Day Facility ranges from 1.125% to 1.750% and the applicable margin for base rate loans ranges from 0.250% to 0.750%. The applicable rate for commitment fees under the ETP 364-Day Facility ranges from 0.125% to 0.225%.

The ETP Credit Facilities contain various covenants including limitations on the creation of indebtedness and liens, and related to the operation and conduct of our business. The ETP Credit Facilities also limit us, on a rolling four quarter basis, to a maximum Consolidated Funded Indebtedness to Consolidated EBITDA ratio, as defined in the underlying credit agreements, of 5.0 to 1, which can generally be increased to 5.5 to 1 during a Specified Acquisition Period. Our Leverage Ratio was 3.96 to 1 at December 31, 2017, as calculated in accordance with the credit agreements.

The agreements relating to the Transwestern senior notes contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

Covenants Related to Panhandle

Panhandle is not party to any lending agreement that would accelerate the maturity date of any obligation due to a failure to maintain any specific credit rating, nor would a reduction in any credit rating, by itself, cause an event of default under any of Panhandle's lending agreements. Financial covenants exist in certain of Panhandle's debt agreements that require Panhandle to maintain a certain level of net worth, to meet certain debt to total capitalization ratios and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. A failure by Panhandle to satisfy any such covenant would give rise to an event of default under the associated debt, which could become immediately due and payable if Panhandle did not cure such default within any permitted cure period or if Panhandle did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

Panhandle's restrictive covenants include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions, cross default and cross-acceleration and prepayment of debt provisions. A breach of any of these covenants could result in acceleration of Panhandle's debt and other financial obligations and that of its subsidiaries.

In addition, Panhandle and/or its subsidiaries are subject to certain additional restrictions and covenants. These restrictions and covenants include limitations on additional debt at some of its subsidiaries; limitations on the use of proceeds from borrowing at some of its subsidiaries; limitations, in some cases, on transactions with its affiliates; limitations on the incurrence of liens; potential limitations on the abilities of some of its subsidiaries to declare and pay dividends and potential limitations

on some of its subsidiaries to participate in Panhandle's cash management program; and limitations on Panhandle's ability to prepay debt.

Covenants Related to Bakken Credit Facility

The Bakken Credit Facility contains standard and customary covenants for a financing of this type, subject to materiality, knowledge and other qualifications, thresholds, reasonableness and other exceptions. These standard and customary covenants include, but are not limited to:

- prohibition of certain incremental secured indebtedness;
- prohibition of certain liens / negative pledge;
- limitations on uses of loan proceeds;
- limitations on asset sales and purchases;
- limitations on permitted business activities;
- limitations on mergers and acquisitions;
- limitations on investments;
- limitations on transactions with affiliates; and
- maintenance of commercially reasonable insurance coverage.

A restricted payment covenant is also included in the Bakken Credit Facility which requires a minimum historic debt service coverage ratio ("DSCR") of not less than 1.20 to 1 (the "Minimum Historic DSCR") with respect each 12-month period following the commercial in-service date of the Dakota Access and ETCO Project in order to make certain restricted payments thereunder.

Compliance with our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2017.

7. LEGACY ETP PREFERRED UNITS:

The Legacy ETP Preferred Units were mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon and were reflected as long-term liabilities in our consolidated balance sheets. The Legacy ETP Preferred Units were entitled to a preferential quarterly cash distribution of $0.445 per Preferred Unit if outstanding on the record dates of the Partnership's common unit distributions. In January 2017, ETP repurchased all of its 1.9 million outstanding Legacy ETP Preferred Units for cash in the aggregate amount of $53 million.

8. EQUITY:

Limited Partner interests are represented by Common, Class E Units, Class G Units, Class I Units, Class J Units and Class K Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. The Partnership's outstanding securities also include preferred units, as described below. No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that ETP GP has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance.

IDRs represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash (as defined in our Partnership Agreement) from operating surplus after the minimum quarterly distribution has been paid. Please read "Quarterly Distributions of Available Cash" below. ETP GP, a wholly-owned subsidiary of ETE, owns all of the IDRs.

Common Units

The change in Common Units was as follows:

	Years Ended December 31,		
	2017 [1]	2016 [1]	2015 [1]
Number of Common Units, beginning of period	794.8	758.5	533.4
Common Units redeemed in connection with certain transactions	—	(26.7)	(77.8)
Common Units issued in connection with public offerings	54.0	—	—
Common Units issued in connection with certain acquisitions	—	13.3	258.2
Common Units issued in connection with the Distribution Reinvestment Plan	12.0	9.9	11.7
Common Units issued in connection with Equity Distribution Agreements	22.6	39.0	31.7
Common Units issued to ETE in a private placement transaction	23.7	—	—
Common Unit increase from Sunoco Logistics Merger [2]	255.4	—	—
Issuance of Common Units under equity incentive plans	1.6	0.8	1.3
Number of Common Units, end of period	1,164.1	794.8	758.5

[1] The historical common units presented have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange in connection with the Sunoco Logistics Merger.

[2] Represents the Sunoco Logistics common units outstanding at the close of the Sunoco Logistics Merger. See Note 1 for discussion on the accounting treatment of the Sunoco Logistics Merger.

Our Common Units are registered under the Securities Exchange Act of 1934 (as amended) and are listed for trading on the NYSE. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under "Quarterly Distributions of Available Cash."

Equity Distribution Program

From time to time, we have sold Common Units through equity distribution agreements. Such sales of Common Units are made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and the sales agent which is the counterparty to the equity distribution agreements.

In connection with the Sunoco Logistics Merger, the previous Energy Transfer Partners, L.P. equity distribution agreement was terminated. In May 2017, the Partnership entered into an equity distribution agreement with an aggregate offering price up to $1.00 billion.

During the year ended December 31, 2017, we issued 22.6 million units for $503 million, net of commissions of $5 million. As of December 31, 2017, $752 million of our Common Units remained available to be issued under our currently effective equity distribution agreement.

Equity Incentive Plan Activity

We issue Common Units to employees and directors upon vesting of awards granted under our equity incentive plans. Upon vesting, participants in the equity incentive plans may elect to have a portion of the Common Units to which they are entitled withheld by the Partnership to satisfy tax-withholding obligations.

Distribution Reinvestment Program

Our Distribution Reinvestment Plan (the "DRIP") provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units.

In connection with the Sunoco Logistics Merger, the previous Energy Transfer Partners, L.P. distribution reinvestment plan was terminated. In July 2017, the Partnership initiated a new distribution reinvestment plan.

During the years ended December 31, 2017, 2016 and 2015, aggregate distributions of $228 million, $216 million, and $360 million, respectively, were reinvested under the DRIP resulting in the issuance in aggregate of 25.5 million Common Units.

As of December 31, 2017, a total of 20.8 million Common Units remain available to be issued under the existing registration statement.

August 2017 Units Offering

In August 2017, the Partnership issued 54 million ETP common units in an underwritten public offering. Net proceeds of $997 million from the offering were used by the Partnership to repay amounts outstanding under its revolving credit facilities, to fund capital expenditures and for general partnership purposes.

January 2017 Private Placement

In January 2017, the Partnership sold 23.7 million ETP Common Units to ETE in a private placement transaction for gross proceeds of approximately $568 million.

Class E Units

There are currently 8.9 million Class E Units outstanding, all of which are currently owned by HHI. The Class E Units generally do not have any voting rights. The Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. As the Class E Units are owned by a wholly-owned subsidiary, the cash distributions on those units are eliminated in our consolidated financial statements. Although no plans are currently in place, management may evaluate whether to retire the Class E Units at a future date.

Class G Units

There are currently 90.7 million Class G Units outstanding, all of which are held by a wholly-owned subsidiary of the Partnership. The Class G Units generally do not have any voting rights. The Class G Units are entitled to aggregate cash distributions equal to 35% of the total amount of cash generated by us and our subsidiaries, other than ETP Holdco, and available for distribution, up to a maximum of $3.75 per Class G Unit per year. Allocations of depreciation and amortization to the Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss. These units are reflected as treasury units in the consolidated financial statements.

Class H Units

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its Common Units representing limited partner interests (the "Redeemed Units") owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the "Class H Units"), which were generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 90.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners and (ii) distributions from available cash at ETP for each quarter equal to 90.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the Class H Units, for any previous quarters. The Class H units were cancelled in connection with the merger of ETP and Sunoco Logistics in April 2017.

Class I Units

In connection with the Bakken Pipeline Transaction discussed in Note 3, in April 2015, ETP issued 100 Class I Units. The Class I Units are generally entitled to: (i) pro rata allocations of gross income or gain until the aggregate amount of such items allocated to the holders of the Class I Units for the current taxable period and all previous taxable periods is equal to the

cumulative amount of all distributions made to the holders of the Class I Units and (ii) after making cash distributions to Class H Units, any additional available cash deemed to be either operating surplus or capital surplus with respect to any quarter will be distributed to the Class I Units in an amount equal to the excess of the distribution amount set forth in our Partnership Agreement, as amended, (the "Partnership Agreement") for such quarter over the cumulative amount of available cash previously distributed commencing with the quarter ended March 31, 2015 until the quarter ending December 31, 2016. The impact of (i) the IDR subsidy adjustments and (ii) the Class I Unit distributions, along with the currently effective IDR subsidies, is included in the table below under "Quarterly Distributions of Available Cash." Subsequent to the April 2017 merger of ETP and Sunoco Logistics, 100 Class I Units remain outstanding.

Bakken Equity Sale

In February 2017, Bakken Holdings Company LLC, an entity in which ETP indirectly owns a 100% membership interest, sold a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by MPLX LP and Enbridge Energy Partners, L.P., for $2.00 billion in cash. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access and ETCO. The remaining 25% of each of Dakota Access and ETCO is owned by wholly-owned subsidiaries of Phillips 66. ETP continues to consolidate Dakota Access and ETCO subsequent to this transaction.

Class K Units

On December 29, 2016, the Partnership issued to certain of its indirect subsidiaries, in exchange for cash contributions and the exchange of outstanding common units representing limited partner interests in the Partnership, Class K Units, each of which is entitled to a quarterly cash distribution of $0.67275 per Class K Unit prior to ETP making distributions of available cash to any class of units, excluding any cash available distributions or dividends or capital stock sales proceeds received by ETP from ETP Holdco. If the Partnership is unable to pay the Class K Unit quarterly distribution with respect to any quarter, the accrued and unpaid distributions will accumulate until paid and any accumulated balance will accrue 1.5% per annum until paid. As of December 31, 2017, a total of 101.5 million Class K Units were held by wholly-owned subsidiaries of ETP.

Sales of Common Units by legacy Sunoco Logistics

Prior to the Sunoco Logistics Merger, we accounted for the difference between the carrying amount of our investment in Sunoco Logistics and the underlying book value arising from the issuance or redemption of units by the respective subsidiary (excluding transactions with us) as capital transactions.

In September and October 2016, a total of 24.2 million common units were issued for net proceeds of $644 million in connection with a public offering and related option exercise. The proceeds from this offering were used to partially fund the acquisition from Vitol.

In March and April 2015, a total of 15.5 million common units were issued in connection with a public offering and related option exercise. Net proceeds of $629 million were used to repay outstanding borrowings under Sunoco Logistics' $2.50 billion Credit Facility and for general partnership purposes.

In 2014, Sunoco Logistics entered into equity distribution agreements pursuant to which Sunoco Logistics may sell from time to time common units having aggregate offering prices of up to $1.25 billion. In connection with the Sunoco Logistics Merger, the previous Sunoco Logistics equity distribution agreement was terminated.

ETP Preferred Units

In November 2017, ETP issued 950,000 of its 6.250% Series A Preferred Units at a price of $1,000 per unit, and 550,000 of its 6.625% Series B Preferred Units at a price of $1,000 per unit.

Distributions on the Series A Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, February 15, 2023, at a rate of 6.250% per annum of the stated liquidation preference of $1,000. On and after February 15, 2023, distributions on the Series A Preferred Units will accumulate at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.028% per annum. The Series A Preferred Units are redeemable at ETP's option on or after February 15, 2023 at a redemption price of $1,000 per Series A Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Distributions on the Series B Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, February 15, 2028, at a rate of 6.625% per annum of the stated liquidation preference of $1,000. On and after February 15, 2028, distributions on the Series B Preferred Units will accumulate at a percentage of the $1,000 liquidation

preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.155% per annum. The Series B Preferred Units are redeemable at ETP's option on or after February 15, 2028 at a redemption price of $1,000 per Series B Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

PennTex Tender Offer and Limited Call Right Exercise

In June 2017, ETP purchased all of the outstanding PennTex common units not previously owned by ETP for $20.00 per common unit in cash. ETP now owns all of the economic interests of PennTex, and PennTex common units are no longer publicly traded or listed on the NASDAQ.

Quarterly Distributions of Available Cash

Under the Partnership's limited partnership agreement, within 45 days after the end of each quarter, the Partnership distributes all cash on hand at the end of the quarter, less reserves established by the general partner in its discretion. This is defined as "available cash" in the partnership agreement. The general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct the Partnership's business. The Partnership will make quarterly distributions to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to the general partner.

If cash distributions exceed $0.0833 per unit in a quarter, the holders of the incentive distribution rights receive increasing percentages, up to 48 percent, of the cash distributed in excess of that amount. These distributions are referred to as "incentive distributions."

The following table shows the target distribution levels and distribution "splits" between the general and limited partners and the holders of the Partnership's incentive distribution rights ("IDRs"):

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	IDRs	Partners [1]
Minimum Quarterly Distribution	$0.0750	—%	100%
First Target Distribution	up to $0.0833	—%	100%
Second Target Distribution	above $0.0833 up to $0.0958	13%	87%
Third Target Distribution	above $0.0958 up to $0.2638	35%	65%
Thereafter	above $0.2638	48%	52%

[1] Includes general partner and limited partner interests, based on the proportionate ownership of each.

The percentage interests shown for the unitholders and the general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

Distributions on common units declared and paid by ETP and Sunoco Logistics during the pre-merger periods were as follows:

Quarter Ended	ETP	Sunoco Logistics
December 31, 2014	$ 0.6633	$ 0.4000
March 31, 2015	0.6767	0.4190
June 30, 2015	0.6900	0.4380
September 30, 2015	0.7033	0.4580
December 31, 2015	0.7033	0.4790
March 31, 2016	0.7033	0.4890
June 30, 2016	0.7033	0.5000
September 30, 2016	0.7033	0.5100
December 31, 2016	0.7033	0.5200

Distributions on common units declared and paid by Post-Merger ETP were as follows:

Quarter Ended	Record Date	Payment Date	Rate
March 31, 2017	May 10, 2017	May 16, 2017	$ 0.5350
June 30, 2017	August 7, 2017	August 15, 2017	0.5500
September 30, 2017	November 7, 2017	November 14, 2017	0.5650
December 31, 2017	February 8, 2018	February 14, 2018	0.5650

In connection with previous transactions, ETE has agreed to relinquish its right to the following amounts of incentive distributions in future periods:

	Total Year
2018	$ 153
2019	128
Each year beyond 2019	33

Distributions declared and paid by ETP to the preferred unitholders were as follows:

			Distribution per Preferred Unit	
Quarter Ended	Record Date	Payment Date	Series A	Series B
December 31, 2017	February 1, 2018	February 15, 2018	$ 15.451	$ 16.378

Accumulated Other Comprehensive Income

The following table presents the components of AOCI, net of tax:

	December 31,	
	2017	2016
Available-for-sale securities	$ 8	$ 2
Foreign currency translation adjustment	(5)	(5)
Actuarial gain related to pensions and other postretirement benefits	(5)	7
Investments in unconsolidated affiliates, net	5	4
Total AOCI, net of tax	$ 3	$ 8

The table below sets forth the tax amounts included in the respective components of other comprehensive income:

	December 31,	
	2017	2016
Available-for-sale securities	$ (2)	$ (2)
Foreign currency translation adjustment	3	3
Actuarial loss relating to pension and other postretirement benefits	3	—
Total	$ 4	$ 1

9. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plan

We have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETP Common Units, restricted units, phantom units, Common Units, distribution equivalent rights ("DERs"), Common Unit appreciation rights, and other unit-based awards. As of December 31, 2017, an aggregate total of 8.4 million ETP Common Units remain available to be awarded under our equity incentive plans.

Restricted Units

We have granted restricted unit awards to employees that vest over a specified time period, typically a five-year service vesting requirement, with vesting based on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. These unit awards entitle the recipients of the unit awards to receive, with respect to each Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. We refer to these rights as "distribution equivalent rights." Under our equity incentive plans, our non-employee directors each receive grants with a five-year service vesting requirement.

The following table shows the activity of the awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2016	9.4	$ 27.68
Legacy Sunoco Logistics unvested awards as of December 31, 2016	3.2	28.57
Awards granted	4.9	17.69
Awards vested	(2.3)	34.22
Awards forfeited	(1.1)	25.03
Unvested awards as of December 31, 2017	14.1	23.18

During the years ended December 31, 2017, 2016, and 2015, the weighted average grant-date fair value per unit award granted was $17.69, $23.82 and $23.47, respectively. The total fair value of awards vested was $40 million, $40 million and $57 million, respectively, based on the market price of ETP Common Units as of the vesting date. As of December 31, 2017, a total of 14.1 million unit awards remain unvested, for which ETP expects to recognize a total of $189 million in compensation expense over a weighted average period of 2.7 years.

Cash Restricted Units. The Partnership previously granted cash restricted units, which entitled the award recipient to receive cash equal to the market value of one ETP Common Unit upon vesting. The Partnership does not currently have any cash restricted units outstanding.

10. INCOME TAXES:

As a partnership, we are not subject to United States federal income tax and most state income taxes. However, the Partnership conducts certain activities through corporate subsidiaries which are subject to federal and state income taxes. The components of the federal and state income tax expense (benefit) are summarized as follows:

	Years Ended December 31,		
	2017	2016	2015
Current expense (benefit):			
Federal	$ 53	$ 18	$ (274)
State	(18)	(35)	(51)
Total	35	(17)	(325)
Deferred expense (benefit):			
Federal	(1,723)	(173)	231
State	192	4	(29)
Total	(1,531)	(169)	202
Total income tax benefit	$ (1,496)	$ (186)	$ (123)

Historically, our effective rate has differed from the statutory rate primarily due to Partnership earnings that are not subject to United States federal and most state income taxes at the partnership level. A reconciliation of income tax expense at the United States statutory rate to the Partnership's income tax benefit for the years ended December 31, 2017, 2016 and 2015 is as follows:

	Years Ended December 31,		
	2017	2016*	2015*
Income tax expense at United States statutory rate of 35 percent	$ 352	$ 139	$ 479
Increase (reduction) in income taxes resulting from:			
Partnership earnings not subject to tax	(457)	(504)	(504)
Federal rate change	(1,559)	—	—
Goodwill impairments	172	223	—
State income taxes (net of federal income tax effects)	131	(17)	(37)
Dividend received deduction	(14)	(15)	(24)
Audit settlement	—	—	(7)
Change in tax status of subsidiary	(124)	—	—
Other	3	(12)	(30)
Income tax benefit	$ (1,496)	$ (186)	$ (123)

* As adjusted. See Note 2.

Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows:

	December 31,	
	2017	2016
Deferred income tax assets:		
Net operating losses and alternative minimum tax credit	$ 604	$ 380
Pension and other postretirement benefits	21	30
Long-term debt	14	32
Other	93	84
Total deferred income tax assets	732	526
Valuation allowance	(189)	(118)
Net deferred income tax assets	$ 543	$ 408
Deferred income tax liabilities:		
Property, plant and equipment	$ (664)	$ (1,054)
Investment in unconsolidated affiliates	(2,664)	(3,728)
Other	(98)	(20)
Total deferred income tax liabilities	(3,426)	(4,802)
Net deferred income taxes	$ (2,883)	$ (4,394)

The table below provides a rollforward of the net deferred income tax liability as follows:

	December 31,	
	2017	2016
Net deferred income tax liability, beginning of year	$ (4,394)	$ (4,082)
Goodwill associated with Sunoco Retail to Sunoco LP transaction (see Note 3)	—	(460)
Tax provision	1,531	169
Other	(20)	(21)
Net deferred income tax liability, end of year	$ (2,883)	$ (4,394)

ETP Holdco and other corporate subsidiaries have federal net operating loss carryforward of $1.57 billion, all of which will expire in 2031 through 2037. Our corporate subsidiaries have $62 million of federal alternative minimum tax credits at December 31, 2017, of which $29 million is expected to be reclassified to current income tax receivable in 2018 pursuant to the Tax Cuts and Jobs Act. Our corporate subsidiaries have state net operating loss carryforward benefits of $210 million, net of federal tax, which expire between 2018 and 2036. A valuation allowance of $186 million is applicable to the state net operating loss carryforward benefits primarily attributable to significant restrictions on their use in the Commonwealth of Pennsylvania and the remaining $3 million valuation allowance is applicable to the federal net operating loss carryforward benefit.

The following table sets forth the changes in unrecognized tax benefits:

	Years Ended December 31,		
	2017	2016	2015
Balance at beginning of year	$ 615	$ 610	$ 440
Additions attributable to tax positions taken in the current year	—	8	—
Additions attributable to tax positions taken in prior years	28	18	178
Reduction attributable to tax positions taken in prior years	(25)	(20)	—
Lapse of statute	(9)	(1)	(8)
Balance at end of year	$ 609	$ 615	$ 610

As of December 31, 2017, we have $605 million ($576 million after federal income tax benefits) related to tax positions which, if recognized, would impact our effective tax rate.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2017, we recognized interest and penalties of less than $3 million. At December 31, 2017, we have interest and penalties accrued of $9 million, net of tax.

Sunoco, Inc. has historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco, Inc.'s 2004 through 2011 years, Sunoco, Inc. filed amended returns with the IRS excluding these government incentive payments from federal taxable income. The IRS denied the amended returns, and Sunoco, Inc. petitioned the Court of Federal Claims ("CFC") in June 2015 on this issue. In November 2016, the CFC ruled against Sunoco, Inc., and Sunoco, Inc. is appealing this decision to the Federal Circuit. If Sunoco, Inc. is ultimately fully successful in this litigation, it will receive tax refunds of approximately $530 million. However, due to the uncertainty surrounding the litigation, a reserve of $530 million was established for the full amount of the litigation. Due to the timing of the litigation and the related reserve, the receivable and the reserve for this issue have been netted in the financial statements as of December 31, 2017.

In December 2015, the Pennsylvania Commonwealth Court determined in Nextel Communications v. Commonwealth ("Nextel") that the Pennsylvania limitation on NOL carryforward deductions violated the uniformity clause of the Pennsylvania Constitution and struck the NOL limitation in its entirety. In October 2017, the Pennsylvania Supreme Court affirmed the decision with respect to the uniformity clause violation; however, the Court reversed with respect to the remedy and instead severed the flat-dollar limitation, leaving the percentage-based limitation intact. Nextel has until April 4, 2018 to file a petition for writ of certiorari with the U.S. Supreme Court. Sunoco, Inc. has recognized approximately $67 million ($53 million after federal income tax benefits) in tax benefit based on previously filed tax returns and certain previously filed protective claims as relates to its cases currently held pending the Nextel matter. However, based upon the Pennsylvania Supreme Court's

October 2017 decision, and because of uncertainty in the breadth of the application of the decision, we have reserved $27 million ($21 million after federal income tax benefits) against the receivable.

In general, ETP and its subsidiaries are no longer subject to examination by the Internal Revenue Service ("IRS"), and most state jurisdictions, for the 2013 and prior tax years. However, Sunoco, Inc. and its subsidiaries are no longer subject to examination by the IRS for tax years prior to 2007.

Sunoco, Inc. has been examined by the IRS for tax years through 2013. However, statutes remain open for tax years 2007 and forward due to carryback of net operating losses and/or claims regarding government incentive payments discussed above. All other issues are resolved. Though we believe the tax years are closed by statute, tax years 2004 through 2006 are impacted by the carryback of net operating losses and under certain circumstances may be impacted by adjustments for government incentive payments.

ETP and its subsidiaries also have various state and local income tax returns in the process of examination or administrative appeal in various jurisdictions. We believe the appropriate accruals or unrecognized tax benefits have been recorded for any potential assessment with respect to these examinations.

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law. Among other provisions, the highest corporate federal income tax rate was reduced from 35% to 21% for taxable years beginning after December 31, 2017. As a result, the Partnership recognized a deferred tax benefit of $1.56 billion in December 2017. For the year ended December 2016, the Partnership recorded an income tax benefit due to pre-tax losses at its corporate subsidiaries.

11. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

Contingent Residual Support Agreement – AmeriGas

In connection with the closing of the contribution of its propane operations in January 2012, ETP previously provided contingent residual support of certain debt obligations of AmeriGas. AmeriGas has subsequently repaid the remainder of the related obligations and ETP no longer provides contingent residual support for any AmeriGas notes.

Guarantee of Sunoco LP Notes

In connection with previous transactions whereby Retail Holdings contributed assets to Sunoco LP, Retail Holdings provided a limited contingent guarantee of collection, but not of payment, to Sunoco LP with respect to (i) $800 million principal amount of 6.375% senior notes due 2023 issued by Sunoco LP, (ii) $800 million principal amount of 6.25% senior notes due 2021 issued by Sunoco LP and (iii) $2.035 billion aggregate principal for Sunoco LP's term loan due 2019. In December 2016, Retail Holdings contributed its interests in Sunoco LP, along with the assignment of the guarantee of Sunoco LP's senior notes, to its subsidiary, ETC M-A Acquisition LLC ("ETC M-A").

On January 23, 2018, Sunoco LP redeemed the previously guaranteed senior notes and issued the following notes for which ETC M-A has also guaranteed collection with respect to the payment of principal amounts:

- $1.00 billion aggregate principal amount of 4.875%, senior notes due 2023;
- $800 million aggregate principal amount of 5.50% senior notes due 2026; and
- $400 million aggregate principal amount of 5.875% senior notes due 2028.

Under the guarantee of collection, ETC M-A would have the obligation to pay the principal of each series of notes once all remedies, including in the context of bankruptcy proceedings, have first been fully exhausted against Sunoco LP with respect to such payment obligation, and holders of the notes are still owed amounts in respect of the principal of such notes. ETC M-A will not otherwise be subject to the covenants of the indenture governing the notes.

FERC Audit

In March 2016, the FERC commenced an audit of Trunkline for the period from January 1, 2013 to present to evaluate Trunkline's compliance with the requirements of its FERC gas tariff, the accounting regulations of the Uniform System of Accounts as prescribed by the FERC, and the FERC's annual reporting requirements. The audit is ongoing.

Commitments

In the normal course of business, ETP purchases, processes and sells natural gas pursuant to long-term contracts and enters into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. ETP

believes that the terms of these agreements are commercially reasonable and will not have a material adverse effect on its financial position or results of operations.

ETP's joint venture agreements require that it funds its proportionate share of capital contributions to its unconsolidated affiliates. Such contributions will depend upon ETP's unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. The table below reflects rental expense under these operating leases included in operating expenses in the accompanying statements of operations, which include contingent rentals, and rental expense recovered through related sublease rental income:

	Years Ended December 31,		
	2017	2016	2015
Rental expense[1]	$ 90	$ 81	$ 176
Less: Sublease rental income	—	(1)	(16)
Rental expense, net	$ 90	$ 80	$ 160

[1] Includes contingent rentals totaling $26 million for the year ended December 31, 2015.

Future minimum lease commitments for such leases are:

Years Ending December 31:	
2018	$ 39
2019	36
2020	37
2021	30
2022	23
Thereafter	92
Future minimum lease commitments	257
Less: Sublease rental income	(8)
Net future minimum lease commitments	$ 249

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude oil are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

Dakota Access Pipeline

On July 25, 2016, the United States Army Corps of Engineers ("USACE") issued permits to Dakota Access consistent with environmental and historic preservation statutes for the pipeline to make two crossings of the Missouri River in North Dakota, including a crossing of the Missouri River at Lake Oahe. After significant delay, the USACE also issued easements to allow the pipeline to cross land owned by the USACE adjacent to the Missouri River in two locations. Also in July, the Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the United States District Court for the District of Columbia against the USACE that challenged the legality of the permits issued for the construction of the Dakota Access pipeline across those waterways and claimed violations of the National Historic Preservation Act ("NHPA"). The SRST also sought a preliminary injunction to rescind the USACE permits while the case is pending. Dakota Access intervened in the case. The SRST soon added a

request for an emergency temporary restraining order ("TRO") to stop construction on the pipeline project. On September 9, 2016, the Court denied SRST's motion for a preliminary injunction, rendering the TRO request moot.

After the September 9, 2016 ruling, the Department of the Army, the DOJ, and the Department of the Interior released a joint statement that the USACE would not grant the easement for the land adjacent to Lake Oahe until the Department of the Army completed a review to determine whether it was necessary to reconsider the USACE's decision under various federal statutes relevant to the pipeline approval.

The SRST appealed the denial of the preliminary injunction to the United States Court of Appeals for the D.C. Circuit and filed an emergency motion in the United States District Court for an injunction pending the appeal, which was denied. The D.C. Circuit then denied the SRST's application for an injunction pending appeal and later dismissed SRST's appeal of the order denying the preliminary injunction motion. The SRST filed an amended complaint and added claims based on treaties between the tribes and the United States and statutes governing the use of government property.

In December 2016, the Department of the Army announced that, although its prior actions complied with the law, it intended to conduct further environmental review of the crossing at Lake Oahe. In February 2017, in response to a presidential memorandum, the Department of the Army decided that no further environmental review was necessary and delivered an easement to Dakota Access allowing the pipeline to cross Lake Oahe. Almost immediately, the Cheyenne River Sioux Tribe ("CRST"), which had intervened in the lawsuit in August 2016, moved for a preliminary injunction and TRO to block operation of the pipeline. These motions raised, for the first time, claims based on the religious rights of the Tribe. The District Court denied the TRO and preliminary injunction, and the CRST appealed and requested an injunction pending appeal in the district court and the D.C. Circuit. Both courts denied the CRST's request for an injunction pending appeal. Shortly thereafter, at CRST's request, the D.C. Circuit dismissed CRST's appeal.

The SRST and the CRST amended their complaints to incorporate religious freedom and other claims. In addition, the Oglala and Yankton Sioux tribes (collectively, "Tribes") have filed related lawsuits to prevent construction of the Dakota Access pipeline project. These lawsuits have been consolidated into the action initiated by the SRST. Several individual members of the Tribes have also intervened in the lawsuit asserting claims that overlap with those brought by the four Tribes.

On June 14, 2017, the Court ruled on SRST's and CRST's motions for partial summary judgment and the USACE's cross-motions for partial summary judgment. The Court rejected the majority of the Tribes' assertions and granted summary judgment on most claims in favor of the USACE and Dakota Access. In particular, the Court concluded that the USACE had not violated any trust duties owed to the Tribes and had generally complied with its obligations under the Clean Water Act, the Rivers and Harbors Act, the Mineral Leasing Act, the National Environmental Policy Act ("NEPA") and other related statutes; however, the Court remanded to the USACE three discrete issues for further analysis and explanation of its prior determinations under certain of these statutes. The Court ordered briefing to determine whether the pipeline should remain in operation during the pendency of the USACE's review process or whether to vacate the existing permits. The USACE and Dakota Access opposed any shutdown of operations of the pipeline during this review process. On October 11, 2017, the Court issued an order allowing the pipeline to remain in operation during the pendency of the USACE's review process. In early October 2017, USACE advised the Court that it expects to complete the additional analysis and explanation of its prior determinations requested by the Court by April 2018.

On December 4, 2017, the Court imposed three conditions on continued operation of the pipeline during the remand process. First, Dakota Access must retain an independent auditor to review its compliance with the conditions and regulations governing its easements and to assess integrity threats to the pipeline. The auditor's report is required to be filed with the Court by April 1, 2018. Second, the Court has directed Dakota Access to continue its work with the Tribes and the USACE to revise and finalize its emergency spill response planning for the section of the pipeline crossing Lake Oahe. Dakota Access is required to file the revised plan with the Court by April 1, 2018. And third, the Court has directed Dakota Access to submit bi-monthly reports during the remand period disclosing certain inspection and maintenance information related to the segment of the pipeline running between the valves on either side of the Lake Oahe crossing. The first report was filed with the court on December 29, 2017.

In November 2017, the Yankton Sioux Tribe ("YST"), moved for partial summary judgment asserting claims similar to those already litigated and decided by the Court in its June 14, 2017 decision on similar motions by CRST and SRST. YST argues that the USACE and Fish and Wildlife Service violated NEPA, the Mineral Leasing Act, the Rivers and Harbors Act, and YST's treaty and trust rights when the government granted the permits and easements necessary for the pipeline. Briefing on YST's motion is ongoing.

While we believe that the pending lawsuits are unlikely to halt or suspend the operation of the pipeline, we cannot assure this outcome. We cannot determine when or how these lawsuits will be resolved or the impact they may have on the Dakota Access project.

Mont Belvieu Incident

On June 26, 2016, a hydrocarbon storage well located on another operator's facility adjacent to Lone Star NGL Mont Belvieu's ("Lone Star") facilities in Mont Belvieu, Texas experienced an over-pressurization resulting in a subsurface release. The subsurface release caused a fire at Lone Star's South Terminal and damage to Lone Star's storage well operations at its South and North Terminals. Normal operations have resumed at the facilities with the exception of one of Lone Star's storage wells. Lone Star is still quantifying the extent of its incurred and ongoing damages and has or will be seeking reimbursement for these losses.

MTBE Litigation

Sunoco, Inc. and/or Sunoco, Inc. (R&M), (now known as Sunoco (R&M), LLC) along with other members of the petroleum industry, are defendants in lawsuits alleging MTBE contamination of groundwater. The plaintiffs, state-level governmental entities, assert product liability claims and additional claims including nuisance, trespass, negligence, violation of environmental laws, and/or deceptive business practices. The plaintiffs seek to recover compensatory damages, and in some cases also seek natural resource damages, injunctive relief, punitive damages, and attorneys' fees.

As of December 31, 2017, Sunoco, Inc. is a defendant in seven cases, including one case each initiated by the States of Maryland, New Jersey, Vermont, Rhode Island, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. The actions brought by the State of Maryland and Commonwealth of Pennsylvania have also named as defendants Energy Transfer Partners, L.P., ETP Holdco Corporation, and Sunoco Partners Marketing & Terminals, L.P. Four of these cases are pending in a multidistrict litigation proceeding in a New York federal court; one is pending in federal court in Rhode Island, one is pending in state court in Vermont, and one is pending in state court in Maryland.

Sunoco, Inc. and Sunoco, Inc. (R&M) have reached a settlement with the State of New Jersey. The Court approved the Judicial Consent Order on December 5, 2017. Dismissal of the case against Sunoco, Inc. and Sunoco, Inc. (R&M) is expected shortly. The Maryland complaint was filed in December 2017 but was not served until January 2018.

It is reasonably possible that a loss may be realized in the remaining cases; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. An adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any such adverse determination occurs, but such an adverse determination likely would not have a material adverse effect on the Partnership's consolidated financial position.

Regency Merger Litigation

Following the January 26, 2015 announcement of the Regency-ETP merger (the "Regency Merger"), purported Regency unitholders filed lawsuits in state and federal courts in Dallas and Delaware asserting claims relating to the Regency Merger. All but one Regency Merger-related lawsuits have been dismissed. On June 10, 2015, Adrian Dieckman ("Dieckman"), a purported Regency unitholder, filed a class action complaint, *Dieckman v. Regency GP LP, et al.*, C.A. No. 11130-CB, in the Court of Chancery of the State of Delaware (the "Regency Merger Litigation"), on behalf of Regency's common unitholders against Regency GP, LP; Regency GP LLC; ETE, ETP, ETP GP, and the members of Regency's board of directors (the "Regency Litigation Defendants").

The Regency Merger litigation alleges that the Regency Merger breached the Regency partnership agreement because Regency's conflicts committee was not properly formed, and the Regency Merger was not approved in good faith. On March 29, 2016, the Delaware Court of Chancery granted the Regency Litigation Defendants' motion to dismiss the lawsuit in its entirety. Dieckman appealed. On January 20, 2017, the Delaware Supreme Court reversed the judgment of the Court of Chancery. On May 5, 2017, Plaintiff filed an Amended Verified Class Action Complaint. The Regency Litigation Defendants then filed Motions to Dismiss the Amended Complaint and a Motion to Stay Discovery on May 19, 2017. On February 20, 2018, the Court of Chancery issued an Order granting in part and denying in part the motions to dismiss, dismissing the claims against all defendants other than Regency GP, LP and Regency GP LLC.

The Regency Litigation Defendants cannot predict the outcome of the Regency Merger Litigation or any lawsuits that might be filed subsequent to the date of this filing; nor can the Regency Litigation Defendants predict the amount of time and expense that will be required to resolve the Regency Merger Litigation. The Regency Litigation Defendants believe the Regency Merger Litigation is without merit and intend to vigorously defend against it and any others that may be filed in connection with the Regency Merger.

Enterprise Products Partners, L.P. and Enterprise Products Operating LLC Litigation

On January 27, 2014, a trial commenced between ETP against Enterprise Products Partners, L.P. and Enterprise Products Operating LLC (collectively, "Enterprise") and Enbridge (US) Inc. Trial resulted in a verdict in favor of ETP against Enterprise that consisted of $319 million in compensatory damages and $595 million in disgorgement to ETP. The jury also found that ETP owed Enterprise $1 million under a reimbursement agreement. On July 29, 2014, the trial court entered a final judgment in favor of ETP and awarded ETP $536 million, consisting of compensatory damages, disgorgement, and pre-judgment interest. The trial court also ordered that ETP shall be entitled to recover post-judgment interest and costs of court and that Enterprise is not entitled to any net recovery on its counterclaims. Enterprise filed a notice of appeal with the Court of Appeals. On July 18, 2017, the Court of Appeals issued its opinion and reversed the trial court's judgment. ETP's motion for rehearing to the Court of Appeals was denied. ETP filed a petition for review with the Texas Supreme Court. Enterprise's response is due February 26, 2018.

Sunoco Logistics Merger Litigation

Seven purported Energy Transfer Partners, L.P. common unitholders (the "ETP Unitholder Plaintiffs") separately filed seven putative unitholder class action lawsuits against ETP, ETP GP, ETP LLC, the members of the ETP Board, and ETE (the "ETP-SXL Defendants") in connection with the announcement of the Sunoco Logistics Merger. Two of these lawsuits were voluntarily dismissed in March 2017. The five remaining lawsuits were consolidated as *In re Energy Transfer Partners, L.P. Shareholder Litig* ., C.A. No. 1:17-cv-00044-CCC, in the United States District Court for the District of Delaware (the "Sunoco Logistics Merger Litigation"). The ETP Unitholder Plaintiffs allege causes of action challenging the merger and the proxy statement/prospectus filed in connection with the Sunoco Logistics Merger (the "ETP-SXL Merger Proxy"). The ETP Unitholder Plaintiffs sought rescission of the Sunoco Logistics Merger or rescissory damages for ETP unitholders, as well as an award of costs and attorneys' fees. On October 5, 2017, the ETP-SXL Defendants filed a Motion to Dismiss the ETP Unitholder Plaintiffs' claims. Rather than respond to the Motion to Dismiss, the ETP Unitholder Plaintiffs chose to voluntarily dismiss their claims without prejudice in November 2017.

The ETP-SXL Defendants cannot predict whether the ETP Unitholder Plaintiffs will refile their claims against the ETP-SXL Defendants or what the outcome of any such lawsuits might be. Nor can the ETP-SXL Defendants predict the amount of time and expense that would be required to resolve such lawsuits. The ETP-SXL Defendants believe the Sunoco Logistics Merger Litigation was without merit and intend to defend vigorously against any future lawsuits challenging the Sunoco Logistics Merger.

Litigation filed by BP Products

On April 30, 2015, BP Products North America Inc. ("BP") filed a complaint with the FERC, *BP Products North America Inc. v. Sunoco Pipeline L.P.,* FERC Docket No. OR15-25-000, alleging that Sunoco Pipeline L.P. ("SPLP"), a wholly-owned subsidiary of ETP, entered into certain throughput and deficiency ("T&D") agreements with shippers other than BP regarding SPLP's crude oil pipeline between Marysville, Michigan and Toledo, Ohio, and revised its proration policy relating to that pipeline in an unduly discriminatory manner in violation of the Interstate Commerce Act ("ICA"). The complaint asked FERC to (1) terminate the agreements with the other shippers, (2) revise the proration policy, (3) order SPLP to restore BP's volume history to the level that existed prior to the execution of the agreements with the other shippers, and (4) order damages to BP of approximately $62 million, a figure that BP reduced in subsequent filings to approximately $41 million.

SPLP denied the allegations in the complaint and asserted that neither its contracts nor proration policy were unlawful and that BP's complaint was barred by the ICA's two-year statute of limitations provision. Interventions were filed by the two companies with which SPLP entered into T&D agreements, Marathon Petroleum Company ("Marathon") and PBF Holding Company and Toledo Refining Company (collectively, "PBF"). A hearing on the matter was held in November 2016.

On May 26, 2017, the Administrative Law Judge Patricia E. Hurt ("ALJ") issued its initial decision ("Initial Decision") and found that SPLP had acted discriminatorily by entering into T&D agreements with the two shippers other than BP and recommended that the FERC (1) adopt the FERC Trial Staff's $13 million alternative damages proposal, (2) void the T&D agreements with Marathon and PBF, (3) re-set each shipper's volume history to the level prior to the effective date of the proration policy, and (4) investigate the proration policy. The ALJ held that BP's claim for damages was not time-barred in its entirety, but that it was not entitled to damages more than two years prior to the filing of the complaint.

On July 26, 2017, each of the parties filed with the FERC a brief on exceptions to the Initial Decision. SPLP challenged all of the Initial Decision's primary findings (except for the adjustment to the individual shipper volume histories). BP and FERC Trial Staff challenged various aspects of the Initial Decision related to remedies and the statute of limitations issue. On September 18 and 19, 2017, all parties filed briefs opposing the exceptions of the other parties. The matter is now awaiting a decision by FERC.

Other Litigation and Contingencies

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2017 and 2016, accruals of approximately $33 million and $77 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued.

No amounts have been recorded in our December 31, 2017 or 2016 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Environmental Matters

Our operations are subject to extensive federal, tribal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations but there can be no assurance that such costs will not be material in the future or that such future compliance with existing, amended or new legal requirements will not have a material adverse effect on our business and operating results. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the issuance of injunctions in affected areas and the filing of federally authorized citizen suits. Contingent losses related to all significant known environmental matters have been accrued and/or separately disclosed. However, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs.

In February 2017, we received letters from the DOJ and Louisiana Department of Environmental Quality notifying Sunoco Pipeline L.P. (“SPLP”) and Mid-Valley Pipeline Company (“Mid-Valley”) that enforcement actions were being pursued for three crude oil releases: (a) an estimated 550 barrels released from the Colmesneil-to-Chester pipeline in Tyler County, Texas (“Colmesneil”) operated and owned by SPLP in February of 2013; (b) an estimated 4,509 barrels released from the Longview-to-Mayersville pipeline in Caddo Parish, Louisiana (a/k/a Milepost 51.5) operated by SPLP and owned by Mid-Valley in October of 2014; and (c) an estimated 40 barrels released from the Wakita 4-inch gathering line in Oklahoma operated and owned by SPLP in January of 2015. In May of this year, we presented to the DOJ, EPA and Louisiana Department of Environmental Quality a summary of the emergency response and remedial efforts taken by SPLP after the releases occurred as well as operational changes instituted by SPLP to reduce the likelihood of future releases. In July, we had a follow-up meeting with the DOJ, EPA and Louisiana Department of Environmental Quality during which the agencies presented their initial demand for civil penalties and injunctive relief. In short, the DOJ and EPA proposed federal penalties totaling $7 million for the three releases along with a demand for injunctive relief, and Louisiana Department of Environmental Quality proposed a state penalty of approximately $1 million to resolve the Caddo Parish release. Neither Texas nor Oklahoma state agencies have joined the penalty discussions at this point. We are currently working on a counteroffer to the Louisiana Department of Environmental Quality.

On January 3, 2018, PADEP issued an Administrative Order to Sunoco Pipeline L.P. directing that work on the Mariner East 2 and 2X pipelines be stopped. The Administrative Order detailed alleged violations of the permits issued by PADEP in

February of 2017, during the construction of the project. Sunoco Pipeline L.P. began working with PADEP representatives immediately after the Administrative Order was issued to resolve the compliance issues. Those compliance issues could not be fully resolved by the deadline to appeal the Administrative Order, so Sunoco Pipeline L.P. took an appeal of the Administrative Order to the Pennsylvania Environmental Hearing Board on February 2, 2018. On February 8, 2018, Sunoco Pipeline L.P. entered into a Consent Order and Agreement with PADEP that (1) withdraws the Administrative Order; (2) establishes requirements for compliance with permits on a going forward basis; (3) resolves the non-compliance alleged in the Administrative Order; and (4) conditions restart of work on an agreement by Sunoco Pipeline L.P. to pay a $12.6 million civil penalty to the Commonwealth of Pennsylvania. In the Consent Order and agreement, Sunoco Pipeline L.P. admits to the factual allegations, but does not admit to the conclusions of law that were made by PADEP. PADEP also found in the Consent Order and Agreement that Sunoco Pipeline L.P. had adequately addressed the issues raised in the Administrative Order and demonstrated an ability to comply with the permits. Sunoco Pipeline L.P. concurrently filed a request to the Pennsylvania Environmental Hearing Board to discontinue the appeal of the Administrative Order. That request was granted on February 8, 2018.

Environmental Remediation

Our subsidiaries are responsible for environmental remediation at certain sites, including the following:

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Legacy sites related to Sunoco, Inc. that are subject to environmental assessments, including formerly owned terminals and other logistics assets, retail sites that Sunoco, Inc. no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco, Inc. is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party ("PRP"). As of December 31, 2017, Sunoco, Inc. had been named as a PRP at approximately 43 identified or potentially identifiable "Superfund" sites under federal and/or comparable state law. Sunoco, Inc. is usually one of a number of companies identified as a PRP at a site. Sunoco, Inc. has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco, Inc.'s purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

To the extent estimable, expected remediation costs are included in the amounts recorded for environmental matters in our consolidated balance sheets. In some circumstances, future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. To the extent that an environmental remediation obligation is recorded by a subsidiary that applies regulatory accounting policies, amounts that are expected to be recoverable through tariffs or rates are recorded as regulatory assets on our consolidated balance sheets.

The table below reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	December 31,	
	2017	2016
Current	$ 36	$ 26
Non-current	314	283
Total environmental liabilities	$ 350	$ 309

In 2013, we established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

During the years ended December 31, 2017 and 2016, the Partnership recorded $23 million and $43 million, respectively, of expenditures related to environmental cleanup programs.

On December 2, 2010, Sunoco, Inc. entered an Asset Sale and Purchase Agreement to sell the Toledo Refinery to Toledo Refining Company LLC ("TRC") wherein Sunoco, Inc. retained certain liabilities associated with the pre-closing time period. On January 2, 2013, USEPA issued a Finding of Violation ("FOV") to TRC and, on September 30, 2013, EPA issued a Notice of Violation ("NOV")/ FOV to TRC alleging Clean Air Act violations. To date, EPA has not issued an FOV or NOV/FOV to Sunoco, Inc. directly but some of EPA's claims relate to the time period that Sunoco, Inc. operated the refinery. Specifically, EPA has claimed that the refinery flares were not operated in a manner consistent with good air pollution control practice for minimizing emissions and/or in conformance with their design, and that Sunoco, Inc. submitted semi-annual compliance reports in 2010 and 2011 to the EPA that failed to include all of the information required by the regulations. EPA has proposed penalties in excess of $200,000 to resolve the allegations and discussions continue between the parties. The timing or outcome of this matter cannot be reasonably determined at this time, however, we do not expect there to be a material impact to our results of operations, cash flows or financial position.

Our pipeline operations are subject to regulation by the United States Department of Transportation under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

In January 2012, we experienced a release on our products pipeline in Wellington, Ohio. In connection with this release, the PHMSA issued a Corrective Action Order under which we are obligated to follow specific requirements in the investigation of the release and the repair and reactivation of the pipeline. This PHMSA Corrective Action Order was closed via correspondence dated November 4, 2016. No civil penalties were associated with the PHMSA Order. We also entered into an Order on Consent with the EPA regarding the environmental remediation of the release site. All requirements of the Order on Consent with the EPA have been fulfilled and the Order has been satisfied and closed. We have also received a "No Further Action" approval from the Ohio EPA for all soil and groundwater remediation requirements. In May 2016, we received a proposed penalty from the EPA and DOJ associated with this release, and continues to work with the involved parties to bring this matter to closure. The timing and outcome of this matter cannot be reasonably determined at this time. However, we do not expect there to be a material impact to our results of operations, cash flows or financial position.

In October 2016, the PHMSA issued a Notice of Probable Violation ("NOPVs") and a Proposed Compliance Order ("PCO") related to our West Texas Gulf pipeline in connection with repairs being carried out on the pipeline and other administrative and procedural findings. The proposed penalty is in excess of $100,000. The case went to hearing in March 2017 and remains open with PHMSA. We do not expect there to be a material impact to our results of operations, cash flows or financial position.

In April 2016, the PHMSA issued a NOPV, PCO and Proposed Civil Penalty related to certain procedures carried out during construction of our Permian Express 2 pipeline system in Texas. The proposed penalties are in excess of $100,000. The case went to Hearing in November 2016 and remains open with PHMSA. We do not expect there to be a material impact to our results of operations, cash flows or financial position.

In July 2016, the PHMSA issued a NOPV and PCO to our West Texas Gulf pipeline in connection with inspection and maintenance activities related to a 2013 incident on our crude oil pipeline near Wortham, Texas. The proposed penalties are in excess of $100,000. The case went to hearing in March 2017 and remains open with PHMSA. We do not expect there to be a material impact to our results of operations, cash flows, or financial position.

In August 2017, the PHMSA issued a NOPV and a PCO in connection with alleged violations on our Nederland to Kilgore pipeline in Texas. The case remains open with PHMSA and the proposed penalties are in excess of $100,000. We do not expect there to be a material impact to our results of operations, cash flows or financial position.

Our operations are also subject to the requirements of the federal OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, Occupational Safety and Health Administration's hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our past costs for

OSHA required activities, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances have not had a material adverse effect on our results of operations but there is no assurance that such costs will not be material in the future.

12. DERIVATIVE ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.

We use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. At hedge inception, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract. Changes in the spreads between the forward natural gas prices and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized.

We use futures, swaps and options to hedge the sales price of natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation and storage segment. These contracts are not designated as hedges for accounting purposes.

We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes we retain for fees in our midstream segment whereby our subsidiaries generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price for the residue gas and NGL. These contracts are not designated as hedges for accounting purposes.

We utilize swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs to manage our storage facilities and the purchase and sale of purity NGL. These contracts are not designated as hedges for accounting purposes.

We use financial commodity derivatives to take advantage of market opportunities in our trading activities which complement our transportation and storage segment's operations and are netted in cost of products sold in our consolidated statements of operations. We also have trading and marketing activities related to power and natural gas in our all other segment which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

The following table details our outstanding commodity-related derivatives:

	December 31, 2017		December 31, 2016	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	1,078	2018	(683)	2017
Basis Swaps IFERC/NYMEX[1]	48,510	2018-2020	2,243	2017
Options – Calls	13,000	2018	—	—
Power (Megawatt):				
Forwards	435,960	2018-2019	391,880	2017-2018
Futures	(25,760)	2018	109,564	2017-2018
Options – Puts	(153,600)	2018	(50,400)	2017
Options – Calls	137,600	2018	186,400	2017
Crude (MBbls) – Futures	—	—	(617)	2017
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	4,650	2018-2020	10,750	2017-2018
Swing Swaps IFERC	87,253	2018-2019	(5,663)	2017
Fixed Swaps/Futures	(4,700)	2018-2019	(52,653)	2017-2019
Forward Physical Contracts	(145,105)	2018-2020	(22,492)	2017
Natural Gas Liquid (MBbls) – Forwards/Swaps	6,679	2018-2019	(5,787)	2017
Refined Products (MBbls) – Futures	(3,783)	2018-2019	(2,240)	2017
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(39,770)	2018	(36,370)	2017
Fixed Swaps/Futures	(39,770)	2018	(36,370)	2017
Hedged Item – Inventory	39,770	2018	36,370	2017

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. To maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We also manage our interest rate exposure by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes:

Term	Type[1]	Notional Amount Outstanding December 31, 2017	Notional Amount Outstanding December 31, 2016
July 2017[2]	Forward-starting to pay a fixed rate of 3.90% and receive a floating rate	$ —	$ 500
July 2018[2]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	300	200
July 2019[2]	Forward-starting to pay a fixed rate of 3.64% and receive a floating rate	300	200
July 2020[2]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	—
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	1,200
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	300

(1) Floating rates are based on 3-month LIBOR.

(2) Represents the effective date. These forward-starting swaps have terms of 30 years with a mandatory termination date the same as the effective date.

Credit Risk

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may, at times, require collateral under certain circumstances to mitigate credit risk as necessary. The Partnership also uses industry standard commercial agreements which allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, gas and electric utilities, midstream companies and independent power generators. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

The Partnership has maintenance margin deposits with certain counterparties in the OTC market, primarily independent system operators, and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on or about the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheets and recognized in net income or other comprehensive income.

Derivative Summary

The following table provides a summary of our derivative assets and liabilities:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31, 2017	December 31, 2016	December 31, 2017	December 31, 2016
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 14	$ —	$ (2)	$ (4)
	14	—	(2)	(4)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	262	338	(281)	(416)
Commodity derivatives	44	24	(55)	(52)
Interest rate derivatives	—	—	(219)	(193)
Embedded derivatives in Legacy ETP Preferred Units	—	—	—	(1)
	306	362	(555)	(662)
Total derivatives	$ 320	$ 362	$ (557)	$ (666)

The following table presents the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset on the consolidated balance sheets that are subject to enforceable master netting arrangements or similar arrangements:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2017	December 31, 2016	December 31, 2017	December 31, 2016
Derivatives without offsetting agreements	Derivative liabilities	$ —	$ —	$ (219)	$ (194)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	44	24	(55)	(52)
Broker cleared derivative contracts	Other current assets (liabilities)	276	338	(283)	(420)
		320	362	(557)	(666)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(20)	(4)	20	4
Counterparty netting	Other current assets (liabilities)	(263)	(338)	263	338
Total net derivatives		$ 37	$ 20	$ (274)	$ (324)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

The following tables summarize the amounts recognized with respect to our derivative financial instruments:

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness		
		Years Ended December 31,		
		2017	2016	2015
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ 26	$ 14	$ 21
Total		$ 26	$ 14	$ 21

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2017	2016	2015
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Cost of products sold	$ 31	$ (35)	$ (11)
Commodity derivatives – Non-trading	Cost of products sold	3	(173)	23
Interest rate derivatives	Losses on interest rate derivatives	(37)	(12)	(18)
Embedded derivatives	Other, net	1	4	12
Total		$ (2)	$ (216)	$ 6

13. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all eligible employees. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries made matching contributions of $38 million, $44 million and $39 million to these 401(k) savings plans for the years ended December 31, 2017, 2016, and 2015, respectively.

Pension and Other Postretirement Benefit Plans

Panhandle

Postretirement benefits expense for the years ended December 31, 2017, 2016 and 2015 reflect the impact of changes Panhandle or its affiliates adopted as of September 30, 2013, to modify its retiree medical benefits program, effective January 1, 2014. The modification placed all eligible retirees on a common medical benefit platform, subject to limits on Panhandle's annual contribution toward eligible retirees' medical premiums. Prior to January 1, 2013, affiliates of Panhandle offered postretirement health care and life insurance benefit plans (other postretirement plans) that covered substantially all employees. Effective January 1, 2013, participation in the plan was frozen and medical benefits were no longer offered to non-union employees. Effective January 1, 2014, retiree medical benefits were no longer offered to union employees.

Sunoco, Inc.

Sunoco, Inc. sponsors a defined benefit pension plan, which was frozen for most participants on June 30, 2010. On October 31, 2014, Sunoco, Inc. terminated the plan, and paid lump sums to eligible active and terminated vested participants in December 2015.

Sunoco, Inc. also has a plan which provides health care benefits for substantially all of its current retirees. The cost to provide the postretirement benefit plan is shared by Sunoco, Inc. and its retirees. Access to postretirement medical benefits was phased

out or eliminated for all employees retiring after July 1, 2010. In March, 2012, Sunoco, Inc. established a trust for its postretirement benefit liabilities. Sunoco made a tax-deductible contribution of approximately $200 million to the trust. The funding of the trust eliminated substantially all of Sunoco, Inc.'s future exposure to variances between actual results and assumptions used to estimate retiree medical plan obligations.

Obligations and Funded Status

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table contains information at the dates indicated about the obligations and funded status of pension and other postretirement plans on a combined basis:

	December 31, 2017			December 31, 2016		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 18	$ 51	$ 165	$ 20	$ 57	$ 180
Interest cost	1	1	4	1	2	4
Amendments	—	—	7	—	—	—
Benefits paid, net	(2)	(6)	(20)	(1)	(7)	(21)
Actuarial (gain) loss and other	2	1	(1)	(2)	(1)	2
Settlements	(18)	—	—	—	—	—
Benefit obligation at end of period	1	47	155	18	51	165
Change in plan assets:						
Fair value of plan assets at beginning of period	12	—	248	15	—	253
Return on plan assets and other	3	—	11	(2)	—	6
Employer contributions	6	—	10	—	—	10
Benefits paid, net	(2)	—	(20)	(1)	—	(21)
Settlements	(18)	—	—	—	—	—
Fair value of plan assets at end of period	1	—	249	12	—	248
Amount underfunded (overfunded) at end of period	$ —	$ 47	$ (94)	$ 6	$ 51	$ (83)
Amounts recognized in the consolidated balance sheets consist of:						
Non-current assets	$ —	$ —	$ 120	$ —	$ —	$ 108
Current liabilities	—	(8)	(2)	—	(7)	(2)
Non-current liabilities	—	(39)	(24)	(6)	(44)	(23)
	$ —	$ (47)	$ 94	$ (6)	$ (51)	$ 83
Amounts recognized in accumulated other comprehensive income (loss) (pre-tax basis) consist of:						
Net actuarial gain	$ —	$ 5	$ (17)	$ —	$ —	$ (12)
Prior service cost	—	—	20	—	—	14
	$ —	$ 5	$ 3	$ —	$ —	$ 2

The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2017			December 31, 2016		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Projected benefit obligation	$ 1	$ 47	N/A	$ 18	$ 51	N/A
Accumulated benefit obligation	1	47	$ 155	18	51	$ 165
Fair value of plan assets	1	—	249	12	—	248

Components of Net Periodic Benefit Cost

	December 31, 2017		December 31, 2016	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Interest cost	$ 2	$ 4	$ 3	$ 4
Expected return on plan assets	—	(9)	(1)	(8)
Prior service cost amortization	—	2	—	1
Net periodic benefit cost	$ 2	$ (3)	$ 2	$ (3)

Assumptions

The weighted-average assumptions used in determining benefit obligations at the dates indicated are shown in the table below:

	December 31, 2017		December 31, 2016	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.27%	2.34%	3.65%	2.34%
Rate of compensation increase	N/A	N/A	N/A	N/A

The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	December 31, 2017		December 31, 2016	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.52%	3.10%	3.60%	3.06%
Expected return on assets:				
Tax exempt accounts	3.50%	7.00%	3.50%	7.00%
Taxable accounts	N/A	4.50%	N/A	4.50%
Rate of compensation increase	N/A	N/A	N/A	N/A

The long-term expected rate of return on plan assets was estimated based on a variety of factors including the historical investment return achieved over a long-term period, the targeted allocation of plan assets and expectations concerning future

returns in the marketplace for both equity and fixed income securities. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to ensure reasonableness and appropriateness.

The assumed health care cost trend rates used to measure the expected cost of benefits covered by Panhandle and Sunoco, Inc.'s other postretirement benefit plans are shown in the table below:

	December 31,	
	2017	2016
Health care cost trend rate	7.20%	6.73%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.99%	4.96%
Year that the rate reaches the ultimate trend rate	2023	2021

Changes in the health care cost trend rate assumptions are not expected to have a significant impact on postretirement benefits.

Plan Assets

For the Panhandle plans, the overall investment strategy is to maintain an appropriate balance of actively managed investments with the objective of optimizing longer-term returns while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its other postretirement plan asset portfolio, Panhandle has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75%.

The investment strategy of Sunoco, Inc. funded defined benefit plans is to achieve consistent positive returns, after adjusting for inflation, and to maximize long-term total return within prudent levels of risk through a combination of income and capital appreciation. The objective of this strategy is to reduce the volatility of investment returns and maintain a sufficient funded status of the plans. In anticipation of the pension plan termination, Sunoco, Inc. targeted the asset allocations to a more stable position by investing in growth assets and liability hedging assets.

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

		Fair Value Measurements at December 31, 2017		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Mutual funds[1]	$ 1	$ 1	$ —	$ —
Total	$ 1	$ 1	$ —	$ —

(1) Comprised of approximately 100% equities as of December 31, 2017.

		Fair Value Measurements at December 31, 2016		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Mutual funds[1]	$ 12	$ 12	$ —	$ —
Total	$ 12	$ 12	$ —	$ —

(1) Comprised of approximately 100% equities as of December 31, 2016.

The fair value of other postretirement plan assets by asset category at the dates indicated is as follows:

		Fair Value Measurements at December 31, 2017		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$ 33	$ 33	$ —	$ —
Mutual funds[1]	146	146	—	—
Fixed income securities	70	—	70	—
Total	$ 249	$ 179	$ 70	$ —

[1] Primarily comprised of approximately 48% equities, 51% fixed income securities and 1% cash as of December 31, 2017.

		Fair Value Measurements at December 31, 2016		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$ 23	$ 23	$ —	$ —
Mutual funds[1]	134	134	—	—
Fixed income securities	91	—	91	—
Total	$ 248	$ 157	$ 91	$ —

[1] Primarily comprised of approximately 31% equities, 66% fixed income securities and 3% cash as of December 31, 2016.

The Level 1 plan assets are valued based on active market quotes. The Level 2 plan assets are valued based on the net asset value per share (or its equivalent) of the investments, which was not determinable through publicly published sources but was calculated consistent with authoritative accounting guidelines.

Contributions

We expect to contribute $8 million to pension plans and $10 million to other postretirement plans in 2018. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Panhandle and Sunoco, Inc.'s estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

Years	Pension Benefits - Unfunded Plans [1]	Other Postretirement Benefits (Gross, Before Medicare Part D)
2018	$ 8	$ 24
2019	6	23
2020	6	21
2021	5	19
2022	4	17
2023 – 2027	15	37

[1] Expected benefit payments of funded pension plans are less than $1 million for the next ten years.

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Panhandle does not expect to receive any Medicare Part D subsidies in any future periods.

14. RELATED PARTY TRANSACTIONS:

In June 2017, the Partnership acquired all of the publicly held PennTex common units through a tender offer and exercise of a limited call right, as further discussed in Note 8.

ETE previously paid us to provide services on its behalf and on behalf of other subsidiaries of ETE, which included the reimbursement of various operating and general and administrative expenses incurred by us on behalf of ETE and its subsidiaries. These agreements expired in 2016.

The Partnership also has related party transactions with several of its equity method investees. In addition to commercial transactions, these transactions include the provision of certain management services and leases of certain assets.

The following table summarizes the affiliate revenues on our consolidated statements of operations:

	Years Ended December 31,		
	2017	2016	2015
Affiliated revenues	$ 697	$ 377	$ 417

The following table summarizes the related company balances on our consolidated balance sheets:

	December 31,	
	2017	2016
Accounts receivable from related companies:		
ETE	$ —	$ 22
Sunoco LP	219	96
FGT	11	15
Other	88	76
Total accounts receivable from related companies	$ 318	$ 209
Accounts payable to related companies:		
Sunoco LP	195	20
Other	14	23
Total accounts payable to related companies	$ 209	$ 43

	December 31,	
	2017	2016
Long-term notes receivable (payable) – related companies:		
Sunoco LP	$ 85	$ 87
Phillips 66	—	(250)
Net long-term notes receivable (payable) – related companies	$ 85	$ (163)

15. REPORTABLE SEGMENTS:

Our financial statements currently reflect the following reportable segments, which conduct their business in the United States, as follows:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- NGL and refined products transportation and services;
- crude oil transportation and services; and

- all other.

The Partnership previously presented its retail marketing business as a separate reportable segment. Due to the transfer of the general partner interest of Sunoco LP from ETP to ETE in 2015 and completion of the dropdown of remaining Retail Marketing interests from ETP to Sunoco LP in March 2016, all of the Partnership's retail marketing business has been deconsolidated. The only remaining retail marketing assets are the limited partner units of Sunoco LP. As of December 31, 2017, the Partnership's interest in Sunoco LP common units consisted of 43.5 million units, representing 43.6% of Sunoco LP's total outstanding common units. Subsequent to Sunoco LP's repurchase of a portion of its common units on February 7, 2018, our investment consists of 26.2 million units, representing 31.8% of Sunoco LP's total outstanding common units. This equity method investment in Sunoco LP has now been aggregated into the all other segment. Consequently, the retail marketing business that was previously consolidated has also been aggregated in the all other segment for all periods presented.

Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation and storage segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our NGL and refined products transportation and services segment are primarily reflected in NGL sales and gathering, transportation, terminalling and other fees. Revenues from our crude oil transportation and services segment are primarily reflected in crude sales. Revenues from our all other segment are primarily reflected in refined product sales.

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, depletion, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for unconsolidated affiliates based on the Partnership's proportionate ownership.

The following tables present financial information by segment:

	Years Ended December 31,		
	2017	2016	2015
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$ 2,891	$ 2,155	$ 1,912
Intersegment revenues	192	458	338
	3,083	2,613	2,250
Interstate transportation and storage:			
Revenues from external customers	915	946	1,008
Intersegment revenues	19	23	17
	934	969	1,025
Midstream:			
Revenues from external customers	2,510	2,342	2,607
Intersegment revenues	4,433	2,837	2,449
	6,943	5,179	5,056
NGL and refined products transportation and services:			
Revenues from external customers	8,326	5,973	4,569
Intersegment revenues	322	436	428
	8,648	6,409	4,997
Crude oil transportation and services:			
Revenues from external customers	11,672	7,539	8,980
Intersegment revenues	31	—	—
	11,703	7,539	8,980
All other:			
Revenues from external customers	2,740	2,872	15,216
Intersegment revenues	161	400	558
	2,901	3,272	15,774
Eliminations	(5,158)	(4,154)	(3,790)
Total revenues	$ 29,054	$ 21,827	$ 34,292

	Years Ended December 31,		
	2017	2016	2015
Cost of products sold:			
Intrastate transportation and storage	$ 2,327	$ 1,897	$ 1,554
Midstream	4,761	3,381	3,264
NGL and refined products transportation and services	6,508	4,553	3,431
Crude oil transportation and services	9,826	6,416	8,158
All other	2,509	2,942	14,029
Eliminations	(5,130)	(4,109)	(3,722)
Total cost of products sold	$ 20,801	$ 15,080	$ 26,714

	Years Ended December 31,		
	2017	2016	2015
Depreciation, depletion and amortization:			
Intrastate transportation and storage	$ 147	$ 144	$ 129
Interstate transportation and storage	214	207	210
Midstream	954	840	720
NGL and refined products transportation and services	401	355	290
Crude oil transportation and services	402	251	218
All other	214	189	362
Total depreciation, depletion and amortization	$ 2,332	$ 1,986	$ 1,929

	Years Ended December 31,		
	2017	2016	2015
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$ (156)	$ 35	$ 32
Interstate transportation and storage	236	193	197
Midstream	20	19	(19)
NGL and refined products transportation and services	33	41	29
Crude oil transportation and services	4	(4)	(9)
All other	19	(225)	239
Total equity in earnings of unconsolidated affiliates	$ 156	$ 59	$ 469

	Years Ended December 31,		
	2017	2016	2015
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 626	$ 613	$ 543
Interstate transportation and storage	1,098	1,117	1,155
Midstream	1,481	1,133	1,237
NGL and refined products transportation and services	1,641	1,496	1,179
Crude oil transportation and services	1,379	834	521
All other	487	540	882
Total Segment Adjusted EBITDA	6,712	5,733	5,517
Depreciation, depletion and amortization	(2,332)	(1,986)	(1,929)
Interest expense, net	(1,365)	(1,317)	(1,291)
Gains on acquisitions	—	83	—
Impairment losses	(920)	(813)	(339)
Losses on interest rate derivatives	(37)	(12)	(18)
Non-cash unit-based compensation expense	(74)	(80)	(79)
Unrealized gains (losses) on commodity risk management activities	56	(131)	(65)
Inventory valuation adjustments	—	—	58
Losses on extinguishments of debt	(42)	—	(43)
Adjusted EBITDA related to unconsolidated affiliates	(984)	(946)	(937)
Equity in earnings from unconsolidated affiliates	156	59	469
Impairment of investments in unconsolidated affiliates	(313)	(308)	—
Other, net	148	115	23
Income before income tax benefit	$ 1,005	$ 397	$ 1,366

	December 31,		
	2017	2016	2015
Assets:			
Intrastate transportation and storage	$ 5,020	$ 5,176	$ 4,882
Interstate transportation and storage	13,518	10,833	11,345
Midstream	20,004	17,873	17,039
NGL and refined products transportation and services	17,600	14,074	11,568
Crude oil transportation and services	17,736	15,909	10,941
All other	4,087	6,240	9,353
Total assets	$ 77,965	$ 70,105	$ 65,128

	Years Ended December 31,		
	2017	2016	2015
Additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs (capital expenditures related to the Partnership's proportionate ownership on an accrual basis):			
Intrastate transportation and storage	$ 175	$ 76	$ 105
Interstate transportation and storage	726	280	866
Midstream	1,308	1,255	2,174
NGL and refined products transportation and services	2,971	2,198	2,853
Crude oil transportation and services	453	1,841	1,358
All other	268	160	811
Total additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs (accrual basis)	$ 5,901	$ 5,810	$ 8,167

	December 31,		
	2017	2016	2015
Advances to and investments in unconsolidated affiliates:			
Intrastate transportation and storage	$ 85	$ 399	$ 406
Interstate transportation and storage	2,118	2,149	2,516
Midstream	126	111	117
NGL and refined products transportation and services	234	235	258
Crude oil transportation and services	22	18	21
All other	1,231	1,368	1,685
Total advances to and investments in unconsolidated affiliates	$ 3,816	$ 4,280	$ 5,003

16. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per Limited Partner unit by quarter does not equal the net income per limited partner unit for the year due to the computation of income allocation between the General Partner and Limited Partners and variations in the weighted average units outstanding used in computing such amounts.

	Quarters Ended				
	March 31*	June 30*	September 30*	December 31	Total Year
2017:					
Revenues	$ 6,895	$ 6,576	$ 6,973	$ 8,610	$ 29,054
Operating income	683	736	779	199	2,397
Net income	393	296	715	1,097	2,501
Common Unitholders' interest in net income (loss)	32	(49)	335	668	986
Basic net income (loss) per Common Unit	$ 0.03	$ (0.04)	$ 0.29	$ 0.57	$ 0.94
Diluted net income (loss) per Common Unit	$ 0.03	$ (0.04)	$ 0.29	$ 0.57	$ 0.93

	Quarters Ended				
	March 31*	June 30*	September 30*	December 31*	Total Year*
2016:					
Revenues	$ 4,481	$ 5,289	$ 5,531	$ 6,526	$ 21,827
Operating income	598	708	594	(139)	1,761
Net income	360	465	94	(336)	583
Common Unitholders' interest in net income (loss)	(71)	58	(252)	(754)	(1,019)
Basic net income (loss) per Common Unit	$ (0.11)	$ 0.06	$ (0.34)	$ (0.97)	$ (1.38)
Diluted net income (loss) per Common Unit	$ (0.11)	$ 0.06	$ (0.34)	$ (0.97)	$ (1.38)

* As adjusted. See Note 2. A reconciliation of amounts previously reported in Forms 10-Q to the quarterly data has not been presented due to immateriality.

The three months ended December 31, 2017 and 2016 reflected the recognition of impairment losses of $920 million and $813 million, respectively. Impairment losses in 2017 were primarily related to our Trunkline, SUG Holding Company, LLC, CDM, Sea Robin and refined products reporting units. Impairment losses in 2016 were primarily related to our PEPL reporting unit, Sea Robin reporting unit and midstream midcontinent operations. The three months ended December 31, 2017 and September 30, 2016 reflected the recognition of a non-cash impairment of our investments in subsidiaries of $313 million and $308 million, respectively, in our interstate transportation and storage segment.

For certain periods reflected above, distributions paid for the period exceeded net income attributable to partners. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period.

17. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

Prior to the Sunoco Logistics Merger, Sunoco Logistics Partners Operations L.P., a subsidiary of Sunoco Logistics was the issuer of multiple series of senior notes that were guaranteed by Sunoco Logistics. Subsequent to the Sunoco Logistics Merger, these notes continue to be guaranteed by the parent company.

These guarantees are full and unconditional. For the purposes of this footnote, Energy Transfer Partners, L.P. is referred to as "Parent Guarantor" and Sunoco Logistics Partners Operations L.P. is referred to as "Subsidiary Issuer." All other consolidated subsidiaries of the Partnership are collectively referred to as "Non-Guarantor Subsidiaries."

The following supplemental condensed consolidating financial information reflects the Parent Guarantor's separate accounts, the Subsidiary Issuer's separate accounts, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations, and the Parent Guarantor's consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent Guarantor's investments in its subsidiaries and the Subsidiary Issuer's investments in its subsidiaries are accounted for under the equity method of accounting. To present the supplemental condensed consolidating financial information on a comparable basis, the prior period financial information has been recast as if the Sunoco Logistics Merger occurred on January 1, 2015.

The consolidating financial information for the Parent Guarantor, Subsidiary Issuer and Non-Guarantor Subsidiaries are as follows:

	December 31, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ (3)	$ 309	$ —	$ 306
All other current assets	—	159	6,063	—	6,222
Property, plant and equipment	—	—	58,437	—	58,437
Investments in unconsolidated affiliates	48,378	11,648	3,816	(60,026)	3,816
All other assets	—	—	9,184	—	9,184
Total assets	$ 48,378	$ 11,804	$ 77,809	$ (60,026)	$ 77,965
Current liabilities	(1,496)	(3,660)	12,150	—	6,994
Non-current liabilities	21,604	7,607	7,609	—	36,820
Noncontrolling interest	—	—	5,882	—	5,882
Total partners' capital	28,270	7,857	52,168	(60,026)	28,269
Total liabilities and equity	$ 48,378	$ 11,804	$ 77,809	$ (60,026)	$ 77,965

	December 31, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ 41	$ 319	$ —	$ 360
All other current assets	—	2	5,281	—	5,283
Property, plant and equipment	—	—	50,917	—	50,917
Investments in unconsolidated affiliates	23,350	10,664	4,280	(34,014)	4,280
All other assets	—	5	9,260	—	9,265
Total assets	$ 23,350	$ 10,712	$ 70,057	$ (34,014)	$ 70,105
Current liabilities	(1,761)	(3,800)	11,764	—	6,203
Non-current liabilities	299	7,313	30,148	(299)	37,461
Noncontrolling interest	—	—	1,232	—	1,232
Total partners' capital	24,812	7,199	26,913	(33,715)	25,209
Total liabilities and equity	$ 23,350	$ 10,712	$ 70,057	$ (34,014)	$ 70,105

	Year Ended December 31, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 29,054	$ —	$ 29,054
Operating costs, expenses, and other	—	1	26,656	—	26,657
Operating income (loss)	—	(1)	2,398	—	2,397
Interest expense, net	—	(156)	(1,209)	—	(1,365)
Equity in earnings of unconsolidated affiliates	2,564	1,242	156	(3,806)	156
Impairment of investments in unconsolidated affiliate	—	—	(313)	—	(313)
Losses on interest rate derivatives	—	—	(37)	—	(37)
Other, net	—	—	168	(1)	167
Income before income tax benefit	2,564	1,085	1,163	(3,807)	1,005
Income tax benefit	—	—	(1,496)	—	(1,496)
Net income	2,564	1,085	2,659	(3,807)	2,501
Less: Net income attributable to noncontrolling interest	—	—	420	—	420
Net income attributable to partners	$ 2,564	$ 1,085	$ 2,239	$ (3,807)	$ 2,081
Other comprehensive income (loss)	$ —	$ —	$ (5)	$ —	$ (5)
Comprehensive income	2,564	1,085	2,654	(3,807)	2,496
Comprehensive income attributable to noncontrolling interest	—	—	420	—	420
Comprehensive income attributable to partners	$ 2,564	$ 1,085	$ 2,234	$ (3,807)	$ 2,076

	Year Ended December 31, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 21,827	$ —	$ 21,827
Operating costs, expenses, and other	—	1	20,065	—	20,066
Operating income (loss)	—	(1)	1,762	—	1,761
Interest expense, net	—	(157)	(1,160)	—	(1,317)
Equity in earnings of unconsolidated affiliates	554	863	59	(1,417)	59
Impairment of investment in unconsolidated affiliate	—	—	(308)	—	(308)
Losses on interest rate derivatives	—	—	(12)	—	(12)
Other, net	—	—	214	—	214
Income before income tax benefit	554	705	555	(1,417)	397
Income tax benefit	—	—	(186)	—	(186)
Net income	554	705	741	(1,417)	583
Less: Net income attributable to noncontrolling interest	—	—	41	—	41
Net income attributable to partners	$ 554	$ 705	$ 700	$ (1,417)	$ 542
Other comprehensive income	$ —	$ —	$ 4	$ —	$ 4
Comprehensive income	554	705	745	(1,417)	587
Comprehensive income attributable to noncontrolling interest	—	—	41	—	41
Comprehensive income attributable to partners	$ 554	$ 705	$ 704	$ (1,417)	$ 546

	Year Ended December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 34,292	$ —	$ 34,292
Operating costs, expenses, and other	—	1	32,064	—	32,065
Operating income (loss)	—	(1)	2,228	—	2,227
Interest expense, net	—	(133)	(1,158)	—	(1,291)
Equity in earnings of unconsolidated affiliates	1,441	526	469	(1,967)	469
Losses on interest rate derivatives	—	—	(18)	—	(18)
Other, net	—	—	(21)	—	(21)
Income before income tax benefit	1,441	392	1,500	(1,967)	1,366
Income tax benefit	—	—	(123)	—	(123)
Net income	1,441	392	1,623	(1,967)	1,489
Less: Net income attributable to noncontrolling interest	—	—	53	—	53
Net income attributable to partners	$ 1,441	$ 392	$ 1,570	$ (1,967)	$ 1,436
Other comprehensive income	$ —	$ —	$ 60	$ —	$ 60
Comprehensive income	1,441	392	1,683	(1,967)	1,549
Comprehensive income attributable to noncontrolling interest	—	—	53	—	53
Comprehensive income attributable to partners	$ 1,441	$ 392	$ 1,630	$ (1,967)	$ 1,496

	Year Ended December 31, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$ 2,564	$ 1,047	$ 4,681	$ (3,807)	$ 4,485
Cash flows from investing activities	(2,240)	(1,368)	(5,672)	3,807	(5,473)
Cash flows from financing activities	(324)	277	981	—	934
Change in cash	—	(44)	(10)	—	(54)
Cash at beginning of period	—	41	319	—	360
Cash at end of period	$ —	$ (3)	$ 309	$ —	$ 306

	Year Ended December 31, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$ 553	$ 675	$ 3,492	$ (1,417)	$ 3,303
Cash flows from investing activities	(976)	(2,400)	(4,431)	1,417	(6,390)
Cash flows from financing activities	423	1,729	768	—	2,920
Change in cash	—	4	(171)	—	(167)
Cash at beginning of period	—	37	490	—	527
Cash at end of period	$ —	$ 41	$ 319	$ —	$ 360

	Year Ended December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$ 1,441	$ 388	$ 2,886	$ (1,968)	$ 2,747
Cash flows from investing activities	(2,271)	(1,815)	(5,702)	1,968	(7,820)
Cash flows from financing activities	830	1,363	2,744	—	4,937
Change in cash	—	(64)	(72)	—	(136)
Cash at beginning of period	—	101	562	—	663
Cash at end of period	$ —	$ 37	$ 490	$ —	$ 527

Exhibit 12.1

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in millions, except for ratio amounts)
(Unaudited)

The merger of legacy ETP and legacy Sunoco Logistics in April 2017 resulted in legacy ETP being treated as the surviving entity from an accounting perspective. Accordingly, the financial data below reflects the consolidated financial information of legacy ETP. In the fourth quarter of 2017, the Partnership changed its accounting policy related to certain inventories; these changes have been applied retrospectively to all periods presented, and the prior period amounts reflected below have been adjusted from those amounts previously reported.

	Years Ended December 31,				
	2017	2016	2015	2014	2013
Fixed Charges:					
Interest expense, net	$ 1,365	$ 1,317	$ 1,291	$ 1,165	$ 1,013
Capitalized interest	283	199	163	101	45
Interest charges included in rental expense	10	9	19	17	16
Series A and B preferred unit distributions	24	—	—	—	—
Distribution to the Legacy Series A Convertible Redeemable Preferred Units	—	—	3	3	6
Total fixed charges	1,682	1,525	1,476	1,286	1,080
Earnings:					
Income from continuing operations before income tax expense and noncontrolling interest	1,005	397	1,366	1,543	846
Less: equity in earnings of unconsolidated affiliates	156	59	469	332	236
Total earnings	849	338	897	1,211	610
Add:					
Fixed charges	1,682	1,525	1,476	1,286	1,080
Amortization of capitalized interest	20	18	11	8	6
Distributed income of equity investees	440	406	440	291	313
Less:					
Interest capitalized	(283)	(199)	(163)	(101)	(45)
Income available for fixed charges	$ 2,708	$ 2,088	$ 2,661	$ 2,695	$ 1,964
Ratio of earnings to fixed charges	1.61	1.37	1.80	2.10	1.82

Exhibit 12.2

SUNOCO LOGISTICS PARTNERS OPERATIONS, L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in millions, except for ratio amounts)
(Unaudited)

	Years Ended December 31,				
	2017	2016	2015	2014	2013
Fixed Charges:					
Interest expense, net	$ 142	$ 157	$ 141	$ 76	$ 77
Capitalized interest	172	111	76	79	21
Interest charges included in rental expense	12	7	7	6	4
Total fixed charges	326	275	224	161	102
Earnings:					
Income from continuing operations before income tax expense and noncontrolling interest	1,142	695	386	275	540
Less: equity in earnings of unconsolidated affiliates	(88)	(39)	(24)	(25)	(21)
Total earnings	1,230	734	410	300	561
Add:					
Fixed charges	326	275	224	161	102
Amortization of capitalized interest	5	4	3	1	1
Distributed income of equity investees	85	25	23	15	14
Less:					
Interest capitalized	(172)	(111)	(76)	(79)	(21)
Income available for fixed charges	$ 1,474	$ 927	$ 584	$ 398	$ 657
Ratio of earnings to fixed charges	4.52	3.37	2.61	2.47	6.44

February 23, 2018

Board of Directors
Energy Transfer Partners, L.L.C.
8111 Westchester Drive, Suite 600
Dallas, TX 75225

Dear Directors:

We are providing this letter solely for inclusion as an exhibit to Energy Transfer Partners, L.P.'s (the "Partnership") 2017 Form 10-K filing pursuant to Item 601 of Regulation S-K.

We have audited the consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017, as set forth in our report dated February 23, 2018. As stated in Note 2 to those financial statements, the Partnership changed its accounting for inventory costing from the last-in, first-out (LIFO) method to the weighted average cost method for all legacy Sunoco Logistics Partners L.P. inventory. Note 2 also states management's belief that the newly adopted accounting principle is preferable in the circumstances because it more closely aligns with the accounting policies across the consolidated entity, given that the other entities are accounting for inventory costing using the weighted average cost method.

With regard to the aforementioned accounting change, it should be understood that authoritative criteria have not been established for evaluating the preferability of one acceptable method of accounting over another acceptable method and, in expressing our concurrence below, we have relied on management's business planning and judgment and on management's determination that this change in accounting principle is preferable.

Based on our reading of management's stated reasons and justification for this change in accounting principle in the Form 10-K, and our discussions with management as to their judgment about the relevant business planning factors relating to the change, we concur with management that the newly adopted method of accounting is preferable in the Partnership's circumstances.

Sincerely,

/s/ GRANT THORNTON LLP

Dallas, Texas

Exhibit 21.1

LIST OF SUBSIDIARIES

SUBSIDIARIES OF ENERGY TRANSFER PARTNERS, L.P., a Delaware limited partnership:

Advanced Diesel LLC, a Idaho limited liability company
Advanced Meter Solutions LLC, a Delaware limited liability company
Aqua-ETC Water Solutions, LLC, a Delaware limited liability company
Arguelles Pipeline S de R.L. DE C.V., a Mexico SRL
Atlantic Petroleum (Out) LLC, a Delaware limited liability company
Atlantic Petroleum Company LLC, a Delaware limited liability company
Atlantic Petroleum Delaware Company LLC, a Delaware limited liability company
Atlantic Pipeline (Out) L.P. Texas limited partnership
Atlantic Refining & Marketing LLC, a Delaware limited liability company
Bakken Gathering LLC, a Delaware limited liability company
Bakken Holdings Company LLC, a Delaware limited liability company
Bakken Pipeline Investments LLC, a Delaware limited liability company
Bayou Bridge Pipeline, LLC, a Delaware limited liability company
Bayview Refining Company, LLC, a Delaware limited liability company
BBP Construction Management, LLC, a Delaware limited liability company
CDM Environmental & Technical Services LLC, a Delaware limited liability company
CDM Resource Management LLC, a Delaware limited liability company
Chalkley Gathering Company, LLC, a Texas limited liability company
Citrus Energy Services, Inc., a Delaware corporation
Citrus ETP Finance LLC, a Delaware limited liability company
Citrus, LLC, a Delaware limited liability company
Clean Air Action Corporation, a Delaware corporation
CMA Pipeline Partnership, LLC, a Texas limited liability company
Comanche Trail Pipeline, LLC, a Texas limited liability company
Connect Gas Pipeline LLC, a Delaware limited liability company
Consorcio Terminales LLC, a Delaware limited liability company
CrossCountry Citrus, LLC, a Delaware limited liability company
CrossCountry Energy, LLC, a Delaware limited liability company
Dakota Access Holdings, LLC, a Delaware limited liability company
Dakota Access Truck Terminals, LLC, a Delaware limited liability company
Dakota Access, LLC, a Delaware limited liability company
DAPL-ETCO Construction Management, LLC, a Delaware limited liability company
DAPL-ETCO Operations Management, LLC, a Delaware limited liability company
Dulcet Acquisition LLC, a Delaware limited liability company
Eastern Gulf Crude Access, LLC, a Delaware limited liability company
Edwards Lime Gathering, LLC, a Delaware limited liability company
ELG Oil LLC, a Delaware limited liability company
ELG Utility LLC, a Delaware limited liability company
Energy Transfer Aviation LLC, a Delaware limited liability company
Energy Transfer, LP, a Delaware limited partnership
Energy Transfer Canada, LLC, a Delaware limited liability company
Energy Transfer Crude Oil Company, LLC, a Delaware limited liability company
Energy Transfer Data Center, LLC, a Delaware limited liability company
Energy Transfer Employee Management Company, a Delaware corporation
Energy Transfer Fuel GP, LLC, a Delaware limited liability company
Energy Transfer Fuel, LP, a Delaware limited partnership
Energy Transfer Group, L.L.C., a Texas limited liability company
Energy Transfer International Holdings LLC, a Delaware limited liability company
Energy Transfer Interstate Holdings, LLC, a Delaware limited liability company
Energy Transfer LNG Export, LLC, a Delaware limited liability company
Energy Transfer Management Holdings, LLC, a Delaware limited liability company
Energy Transfer Mexicana, LLC, a Delaware limited liability company

Energy Transfer Rail Company, LLC, a Delaware limited liability company
Energy Transfer Retail Power, LLC, a Delaware limited liability company
Energy Transfer Technologies, Ltd., a Texas limited partnership
Energy Transfer Terminalling Company, LLC, a Delaware limited liability company
ET Company I, Ltd., a Texas limited partnership
ET Crude Oil Terminals, LLC, a Delaware limited partnership
ET Fuel Pipeline, L.P., a Delaware limited partnership
ET Rover Pipeline Canada, ULC, a BC, Canada unlimited liability company
ET Rover Pipeline LLC, a Delaware limited liability company
ETC Bayou Bridge Holdings, LLC, a Delaware limited liability company
ETC Compression, LLC, a Delaware limited liability company
ETC Endure Energy L.L.C., a Delaware limited liability company
ETC Energy Transfer, LLC, a Delaware limited liability company
ETC Fayetteville Express Pipeline, LLC, a Delaware limited liability company
ETC Fayetteville Operating Company, LLC, a Delaware limited liability company
ETC Field Services LLC, a Delaware limited liability company
ETC Gas Company, Ltd., a Texas limited partnership
ETC Gathering, LLC, a Texas limited liability company
ETC Hydrocarbons, LLC, a Texas limited liability company
ETC Illinois LLC, a Delaware limited liability company
ETC Interstate Procurement Company, LLC, a Delaware limited liability company
ETC Intrastate Procurement Company, LLC, a Delaware limited liability company
ETC Katy Pipeline, Ltd., a Texas limited partnership
ETC M-A Acquisition LLC, a Delaware limited liability company
ETC Marketing, Ltd., a Texas limited partnership
ETC Midcontinent Express Pipeline, L.L.C., a Delaware limited liability company
ETC New Mexico Pipeline, L.P., a New Mexico limited partnership
ETC NGL Marketing, LLC, a Texas limited liability company
ETC NGL Transport, LLC, a Texas limited liability company
ETC North Dakota Terminalling, LLC, a Delaware limited liability company
ETC Northeast Development, LLC, a West Virigina limited liability company
ETC Northeast Field Services LLC, a Delaware limited liability company
ETC Northeast Holdings, LLC, a Delaware limited liability company
ETC Northeast Midstream, LLC, a Delaware limited liability company
ETC Northeast Pipeline, LLC, a Delaware limited liability company
ETC Oasis GP, LLC a Texas limited liability company
ETC Oasis, L.P., a Delaware limited partnership
ETC Texas Pipeline, Ltd., a Texas limited partnership
ETC Tiger Pipeline, LLC, a Delaware limited liability company
ETC Tilden System LLC, a Delaware limited liability company
ETC Water Solutions, LLC, a Delaware limited liability company
ETCO Holdings LLC, a Delaware limited liability company
ETP Crude LLC, a Texas limited liability company
ETP Holdco Corporation, a Delaware corporation
ETP Retail Holdings, LLC, a Delaware limited liability company
Evergreen Assurance, LLC, a Delaware limited liability company
Evergreen Capital Holdings, LLC, a Delaware limited liability company
Evergreen Resources Group, LLC, a Delaware limited liability company
Explorer Pipeline Company, a Delaware corporation
Fayetteville Express Pipeline, LLC, a Delaware limited liability company
FEP Arkansas Pipeline, LLC, an Arkansas limited liability company
Fieldcrest Resources LLC, a Delaware limited liability company
Five Dawaco, LLC, a Texas limited liability company
Florida Gas Transmission Company, LLC, a Delaware limited liability company
FLST LLC, a Delaware limited liability company
FrontStreet Hugoton LLC, a Delaware limited liability company

Galveston Bay Gathering, LLC, a Texas limited liability company
Gulf States Transmission LLC, a Louisiana limited liability company

Helios Assurance Company, a Limited Bermuda other
Heritage ETC GP, L.L.C., a Delaware limited liability company
Heritage ETC, L.P., a Delaware limited partnership
Heritage Holdings, Inc., a Delaware corporation
Houston Pipe Line Company LP, a Delaware limited partnership
HP Houston Holdings, L.P., a Delaware limited partnership
HPL Asset Holdings LP, a Delaware limited partnership
HPL Consolidation LP, a Delaware limited partnership
HPL GP, LLC, a Delaware limited liability company
HPL Holdings GP, L.L.C., a Delaware limited liability company
HPL Houston Pipe Line Company, LLC, a Delaware limited liability company
HPL Leaseco LP, a Delaware limited partnership
HPL Resources Company LP, a Delaware limited partnership
HPL Storage GP LLC, a Delaware limited liability company
Inland Corporation, an Ohio corporation
Jalisco Corporation, a California corporation
Japan Sun Oil Company, Ltd., a Japan other
K Rail LLC, a Delaware limited liability company
Kanawha Rail LLC, a Delaware limited liability company
LA GP, LLC, a Texas limited liability company
La Grange Acquisition, L.P., a Texas limited partnership
LaGrange-ETCOP Operating Company, LLC, a Delaware limited liability company
Lake Charles Exports, LLC, a Delaware limited liability company
Lake Charles LNG Export Company, LLC, a Delaware limited liability company
Lavan Petroleum Company (LAPCO), an Iran, Islamic Republic of other
Lee 8 Storage Partnership, a Delaware limited partnership
Lesley Company LLC, a Delaware limited liability company
LG PL, LLC, a Texas limited liability company
LGM, LLC, a Texas limited liability company
Liberty Pipeline Group, LLC, a Delaware limited liability company
Libre Insurance Company, Ltd., a Bermuda corporation
LJL, LLC, a West Virginia limited liability company
Loadout LLC, a Delaware limited liability company
Lobo Pipeline Company LLC, a Delaware limited liability company
Lone Star NGL Asset GP LLC, a Delaware limited liability company
Lone Star NGL Asset Holdings II LLC, a Delaware limited liability company
Lone Star NGL Asset Holdings LLC, a Delaware limited liability company
Lone Star NGL Development LP, a Delaware limited partnership
Lone Star NGL Fractionators LLC, a Delaware limited liability company
Lone Star NGL Hattiesburg LLC, a Delaware limited liability company
Lone Star NGL LLC, a Delaware limited liability company
Lone Star NGL Marketing LLC, a Delaware limited liability company
Lone Star NGL Mont Belvieu GP LLC, a Delaware limited liability company
Lone Star NGL Mont Belvieu Pipelines LLC, a Delaware limited liability company
Lone Star NGL Mont Belvieu LP, a Delaware limited partnership
Lone Star NGL Pipeline LP, a Delaware limited partnership
Lone Star NGL Product Services LLC, a Delaware limited liability company
Lone Star NGL Refinery Services LLC, a Delaware limited liability company
Lone Star NGL Sea Robin LLC, a Delaware limited liability company
Lugrasa, S.A., a Panama corporation
Mascot, Inc. (MA), a Massachusetts corporation
Materials Handling Solutions LLC, a Delaware limited liability company
Mi Vida JV LLC, a Delaware limited liability company
Midcontinent Express Pipeline LLC, a Delaware limited liability company
Mid-Continent Pipe Line (Out) LLC, a Texas limited liability company
Midstream Gas Services, LLC, a Texas limited liability company

Midstream Logistics LLC, a Delaware limited liability company
Mid-Valley Pipeline Company, an Ohio corporation

Midwest Connector Capital Company LLC, a Delaware limited liability company
Oasis Partner Company, a Delaware corporation
Oasis Pipe Line Company Texas L.P., a Texas limited partnership
Oasis Pipe Line Company, a Delaware corporation
Oasis Pipe Line Finance Company, a Delaware corporation
Oasis Pipe Line Management Company, a Delaware corporation
Oasis Pipeline, LP, a Texas limited partnership
Ohio River System LLC, a Delaware limited liability company
Oil Casualty Insurance, Ltd., a Bermuda Limited Company
Oil Insurance Limited, Bermuda limited company
Orbit Gulf Coast NGL Exports, LLC, a Delaware limited liability company
Pacific Ethanol Central, LLC, a Delaware limited liability company
Pan Gas Storage LLC , a Delaware limited liability company
Panhandle Eastern Pipe Line Company, LP, a Delaware limited partnership
Panhandle Energy LNG Services, LLC, a Delaware limited liability company
Panhandle Storage LLC, a Delaware limited liability company
PEI Power Corporation, a Pennsylvania corporation
PEI Power II, LLC, a Pennsylvania corporation
Pelico Pipeline, LLC, a Delaware limited liability company
Penn Virginia Operating Co., LLC, a Delaware limited liability company
PennTex Midstream GP, LLC, a Delaware limited liability company
PennTex Midstream Operating, LLC, a Delaware limited liability company
PennTex Midstream Partners, LP, a Delaware limited partnership
PennTex Midstream Partners, LLC, a Delaware limited liability company
PennTex NLA Holdings, LLC, a Delaware limited liability company
PennTex North Louisiana, LLC, a Delaware limited liability company
PennTex North Louisiana Operating 3, LLC, a Delaware limited liability company
Permian Express Partners LLC, a Delaware limited liability company
Permian Express Partners Operating LLC, a Texas limited liability company
Permian Express Terminal LLC, a Delaware limited liability company
PES Equity Holdings, LLC, a Delaware limited liability company
PES Holdings, LLC, a Delaware limited liability company
PG Energy, Inc., a Pennsylvania corporation
Philadelphia Energy Solutions LLC, a Delaware limited liability company
Philadelphia Energy Solutions Refining and Marketing LLC, a Delaware limited liability company
Price River Terminal, LLC, a Texas limited liability company
Puerto Rico Sun Oil Company LLC, a Delaware limited liability company
PVR Midstream JV Holdings LLC, a Delaware limited liability company
Ranch Westex JV LLC, a Delaware limited liability company
Red Bluff Express Pipeline, LLC, a Delaware limited liability company
Regency Crude Marketing LLC, a Delaware limited liability company
Regency Employees Management Holdings LLC, a Delaware limited liability company
Regency Energy Finance Corp., a Delaware corporation
Regency Energy Partners LP, a Delaware limited partnership
Regency ERCP LLC, a Delaware limited liability company
Regency Gas Services LP, a Delaware limited partnership
Regency GOM LLC, a Texas limited liability company
Regency GP LLC, a Delaware limited liability company
Regency GP LP, a Delaware limited partnership
Regency Haynesville Intrastate Gas LLC, a Delaware limited liability company
Regency Hydrocarbons LLC, an Oklahoma limited liability company
Regency Intrastate Gas LP, a Delaware limited partnership
Regency Laverne LLC, an Oklahoma limited liability company
Regency Liquids Pipeline LLC, a Delaware limited liability company
Regency Marcellus Gas Gathering LLC, a Delaware limited liability company
Regency Mi Vida LLC, a Delaware limited liability company

Regency NEPA Gas Gathering LLC, a Texas limited liability company
Regency OLP GP LLC, a Delaware limited liability company

Regency Pipeline LLC, a Delaware limited liability company
Regency Quitman Gathering LLC, a Delaware limited liability company
Regency Ranch JV LLC, a Delaware limited liability company
Regency Texas Pipeline LLC, a Delaware limited liability company
Regency Utica Gas Gathering LLC, a Delaware limited liability company
Regency Utica Holdco LLC, a Delaware limited liability company
Regency Vaughn Gathering LLC, a Texas limited liability company
RGP Marketing LLC, a Texas limited liability company
RGP Westex Gathering Inc., a Texas corporation
RIGS GP LLC, a Delaware limited liability company
RIGS Haynesville Partnership Co., a Delaware partnership
Rover Pipeline LLC, a Delaware limited liability company
RSS Water Services LLC, a Delaware limited liability company
Sea Robin Pipeline Company, LLC , a Delaware limited liability company
SEC Energy Products & Services, L.P., a Texas limited partnership
SEC Energy Realty GP, LLC, a Texas limited liability company
SEC General Holdings, LLC, a Texas limited liability company
SEC-EP Realty Ltd., a Texas limited partnership
Southern Union Gas Company, Inc., a Texas corporation
Southern Union Panhandle LLC, a Delaware limited liability company
SU Gas Services Operating Company, Inc., a Delaware corporation
SU Holding Company, Inc., a Delaware corporation
SUG Holding Company, LLC, a Delaware limited liability company
Sun Alternate Energy Corporation, a Delaware corporation
Sun Atlantic Refining and Marketing B.V., a Netherlands other
Sun Atlantic Refining and Marketing B.V., LLC, a Delaware limited liability company
Sun Atlantic Refining and Marketing Company, LLC, a Delaware limited liability company
Sun Canada, Inc., a Delaware corporation
Sun Company, Inc., a Delaware corporation
Sun Company, Inc., a Pennsylvania corporation
Sun International Limited, a Bermuda corporation
Sun Lubricants and Specialty Products Inc., a Quebec corporation
Sun Mexico One, Inc., a Delaware corporation
Sun Mexico Two, Inc., a Delaware corporation
Sun Oil Company, a Delaware corporation
Sun Oil Export Company, a Delaware corporation
Sun Oil International, Inc., a Delaware corporation
Sun Petrochemicals LLC, a Delaware corporation
Sun Pipe Line Company of Delaware LLC, a Delaware limited liability company
Sun Pipe Line Company, LLC, a Texas limited liability company
Sun Pipe Line Delaware (Out) LLC, a Delaware limited liability company
Sun Refining and Marketing Company, a Delaware corporation
Sun Services Corporation, a Pennsylvania corporation
Sun Transport, LLC, a Pennsylvania limited liability company
Suncrest Resources LLC, a Delaware limited liability company
Sun-Del Pipeline LLC, a Delaware limited liability company
Sun-Del Services, Inc., a Delaware corporation

Sunoco (R&M), LLC, a Pennsylvania limited liability company
Sunoco de Mexico, S.A. de C.V., a Mexico other
Sunoco Logistics Partners GP LLC, a Delaware limited liability company
Sunoco Logistics Partners Operations GP LLC, a Delaware limited liability company
Sunoco Logistics Partners Operations L.P., a Delaware limited partnership
Sunoco Midland Gathering LLC, a Texas limited liability company

Sunoco Midland Terminal LLC, a Texas limited liability company
Sunoco Overseas, Inc., a Delaware corporation

Sunoco Partners Marketing & Terminals L.P., a Texas limited partnership
Sunoco Partners NGL Facilities LLC, a Delaware limited liability company
Sunoco Partners Operating LLC, a Delaware limited liability company

Sunoco Partners Real Estate Acquisition LLC, a Delaware limited liability company
Sunoco Partners Rockies LLC, a Delaware limited liability company
Sunoco Pipeline Acquisition LLC, a Delaware limited liability company
Sunoco Pipeline L.P., a Texas limited partnership
Sunoco Power Marketing L.L.C., a Pennsylvania limited liability company
Sunoco Receivables Corporation, Inc., a Delaware corporation
Sunoco, Inc., a Pennsylvania corporation
Sweeney Gathering, L.P., a Texas limited liability company
SXL Acquisition Sub LLC, a Delaware limited liability company
TETC, LLC, a Texas limited liability company
Texas Energy Transfer Company, Ltd., a Texas limited partnership
Texas Energy Transfer Power, LLC, a Texas limited liability company
The New Claymont Investment Company, a Delaware corporation
The Energy Transfer/Sunoco Foundation, a Pennsylvania non-profit
Toney Fork LLC, a Delaware limited liability company
Trade Star, LLC, a Idaho limited liability company
Trade Star Holdings, LLC, a Delaware limited liability company
Trade Star Leasing LLC, a Idaho limited liability company
Trade Star Properties LLC, a Idaho limited liability company
Trade Star Willston, LLC, a Idaho limited liability company
Trans-Pecos Pipeline, LLC, a Texas limited liability company
Transwestern Pipeline Company, LLC, a Delaware limited liability company
Trunkline Field Services LLC, a Delaware limited liability company
Trunkline Gas Company, LLC, a Delaware limited liability company
Trunkline LNG Holdings LLC, a Delaware limited liability company
Venezoil, C.A., a Venezuela other
Vista Mar Pipeline, LLC, a Texas limited liability company
Waha Express Pipeline, LLC, a Delaware limited liability company
West Shore Pipe Line Company, a Delaware corporation
West Texas Gathering Company, a Delaware corporation
West Texas Gulf Pipe Line Company, a Delaware corporation
Westex Energy LLC, a Delaware limited liability company
WGP-KHC, LLC, a Delaware limited liability company
Whiskey Bay Gathering Company, LLC, a Delaware limited liability company
Wolverine Pipe Line Company, a Delaware corporation
Yellowstone Pipe Line Company, a Delaware corporation

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 23, 2018, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Energy Transfer Partners, L.P. on Form 10-K for the year ended December 31, 2017. We consent to the incorporation by reference of said reports in the Registration Statements of Energy Transfer Partners, L.P. on Forms S-3 (File No. 333-221411, File No. 333-219224, and File No. 333-212962) and on Forms S-8 (File No. 333-217592, File No. 333-208327, and File No. 333-96897).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 23, 2018

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kelcy L. Warren, certify that:

1. I have reviewed this annual report on Form 10-K of Energy Transfer Partners, L.P. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize, and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Thomas E. Long, certify that:

1. I have reviewed this annual report on Form 10-K of Energy Transfer Partners, L.P. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize, and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ Thomas E. Long

Thomas E. Long
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Energy Transfer Partners, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kelcy L. Warren, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 23, 2018

/s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer

*A signed original of this written statement required by 18 U.S.C. Section 1350 has been provided to and will be retained by Energy Transfer Partners, L.P.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Energy Transfer Partners, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Thomas E. Long, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 23, 2018

/s/ Thomas E. Long
Thomas E. Long
Chief Financial Officer

*A signed original of this written statement required by 18 U.S.C. Section 1350 has been provided to and will be retained by Energy Transfer Partners, L.P.