Energy Transfer Operating, L.P.
Form 10-K
February 22, 2019
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number 1-31219
ENERGY TRANSFER OPERATING, 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
Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	New York Stock Exchange
Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred 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 ý 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 ý
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 ý No ¨
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ý 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 ý 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 ý

The aggregate market value as of June 30, 2018, 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 $21.63 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.

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 Operating, L.P. (the “Partnership,” or “ETO”) 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,” “
“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
AOCI	accumulated other comprehensive income (loss)
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 and CDM Environmental & Technical Services LLC, collectively
Citrus	Citrus, LLC, which owns 100% of FGT
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
EPA	United States Environmental Protection Agency
ET	Energy Transfer LP, a publicly traded partnership and the owner of ETP LLC for the periods presented herein
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
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETO
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, as amended
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.
IDRs	incentive distribution rights
KMI	Kinder Morgan Inc.
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC)
LCL	Lake Charles LNG Export Company, LLC
LDEQ	Louisiana Department of Environmental Quality
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

Mid-Valley	Mid-Valley Pipeline Company
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 Refining and Marketing LLC
Phillips 66	Phillips 66 Partners LP
PHMSA	Pipeline Hazardous Materials Safety Administration
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings, LLC, a subsidiary of ETO
RIGS	Regency Intrastate Gas System
Rover	Rover Pipeline LLC, a subsidiary of ETO
Sea Robin	Sea Robin Pipeline Company, LLC, a subsidiary of Panhandle
SEC	Securities and Exchange Commission
Series A Preferred Units	6.250% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series B Preferred Units	6.625% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series C Preferred Units	7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series D Preferred Units	7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Shell	Royal Dutch Shell plc
SPLP	Sunoco Pipeline L.P.
Sunoco GP	Sunoco GP LLC, the general partner of Sunoco LP
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
Transwestern	Transwestern Pipeline Company, LLC
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle
USAC	USA Compression Partners, LP

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.

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PART I

ITEM 1. BUSINESS

Overview

We (Energy Transfer Operating, L.P., a Delaware limited partnership, "ETO" or the "Partnership") are a consolidated subsidiary of Energy Transfer LP ("ET"). In October 2018, ET completed the merger of ETO with a wholly-owned subsidiary of ET in a unit-for-unit exchange (the "Energy Transfer Merger"), as discussed further below, at which time the Partnership changed its name from Energy Transfer Partners, L.P. to Energy Transfer Operating, L.P.

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 ET. The primary activities in which we are engaged, all of which are in the United States, are as follows:

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

In addition, we own investments in other businesses, including Sunoco LP and USAC, both of which are publicly traded master limited partnerships.

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The following chart summarizes our organizational structure as of February 15, 2019. For simplicity, certain immaterial entities and ownership interest have not been depicted.

Unless the context requires otherwise, the Partnership and its subsidiaries are collectively referred to in this report as “we,” “us,” “ETO,” “Energy Transfer” or “the Partnership.”

Significant Achievements in 2018 and Beyond

Our significant strategic transactions in 2018 and beyond included the following, as discussed in more detail herein:

Strategic Transactions Related to the Partnership

- In October 2018, ET and ETO (previously named Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P., respectively, prior to the October 2018 transactions) completed the merger of ETO with a wholly-owned subsidiary of ET in a unit-for-unit exchange (the “Energy Transfer Merger”). Immediately prior to the Energy Transfer Merger, (i) the IDRs in ETO were converted into ETO Common Units, (ii) the general partner interest in ETO was converted into ETO Common Units, (iii) ET’s interests in Sunoco LP, USAC and their respective general partners were contributed to ETO, and (iv) certain other

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interests owned by ET were contributed to ETO. The Energy Transfer Merger and these related transactions are discussed further in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

- In April 2018, ETO contributed to USAC all of the issued and outstanding membership interests of CDM for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 USAC common units, (ii) 6,397,965 units of a new class of units representing limited partner interests in USAC ("USAC Class B Units") and (iii) $1.23 billion in cash, including customary closing adjustments (the "CDM Contribution"). The USAC Class B Units have substantially all of the rights and obligations of a USAC common unit, except the USAC Class B Units will not participate in distributions for the first four quarters following the closing date of April 2, 2018. Each USAC Class B Unit will automatically convert into one USAC common unit on the first business day following the record date attributable to the quarter ending June 30, 2019. ETO subsequently obtained control of USAC in connection with the transactions related to the Energy Transfer Merger in October 2018, as discussed above.
- ETO previously owned a 49.99% interest in HPC, which owns RIGS. In April 2018, ETO acquired the remaining 50.01% interest in HPC. Prior to April 2018, HPC was reflected as an unconsolidated affiliate in ETO's financial statements; beginning in April 2018, RIGS is reflected as a wholly-owned subsidiary in ETO's financial statements.
- On January 23, 2018, Sunoco LP closed on an asset purchase agreement with 7-Eleven, Inc., a Texas corporation ("7-Eleven"), and SEI Fuel Services, Inc., a Texas corporation and wholly-owned subsidiary of 7-Eleven. Under the agreement, Sunoco LP sold a portfolio of approximately 1,030 company-operated retail fuel outlets in 19 geographic regions, together with ancillary businesses and related assets, including the proprietary Laredo Taco Company brand, for an aggregate purchase price of $3.2 billion.

Significant Organic Growth Projects

Our significant announced organic growth projects in 2018 included the following, as discussed in more detail herein:

- In September 2018, ETO, Magellan Midstream Partners, L.P., MPLX LP and Delek US Holdings, Inc. announced that they have received sufficient commitments to proceed with plans to construct a new 30-inch diameter common carrier pipeline, the Permian Gulf Coast ("PGC") pipeline, to transport crude oil from the Permian Basin to the Texas Gulf Coast region. The transaction structure for this project has not been finalized.
- In August 2018, the Partnership received approval to commence service on 100% of the long-haul contractual commitments on Rover to begin September 1, 2018, and on November 2, 2018, the Partnership announced that it received approval to commence service on the final laterals needed to complete the Rover pipeline project.
- In March 2018, ETO and Satellite Petrochemical USA Corp. ("Satellite") entered into definitive agreements to form a joint venture, Orbit Gulf Coast NGL Exports, LLC ("Orbit"), with the purpose of constructing a new export terminal on the United States Gulf Coast to provide ethane to Satellite for consumption at its ethane cracking facilities in China.

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, power generators and other third-party pipelines. Through our intrastate transportation and storage segment, we own and operate (through wholly-owned or through joint venture interests) approximately 9,400 miles of natural gas transportation pipelines with approximately 21 Bcf/d of transportation capacity and three natural gas storage facilities located in the state of Texas.

We own a 70% interest in the Red Bluff Express Pipeline, a 100-mile intrastate pipeline system that connects our Orla Plant, as well as third-party plants to the Waha Oasis Header.

Energy Transfer operates one of the largest intrastate pipeline systems in the United States providing energy logistics to major trading hubs and industrial 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 (Permian, Barnett, Haynesville and Eagle Ford Shale) through our Oasis pipeline, our ETC Katy pipeline, our natural gas pipeline and storage systems that are referred to as the ET Fuel System, and our HPL System, as further described below.

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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 a fee 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 supply sources including other transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users and other pipelines. Through our interstate transportation and storage segment, we directly own and operate approximately 12,200 miles of interstate natural gas pipelines with approximately 10.3 Bcf/d of transportation capacity and another approximately 6,750 miles and 10.5 Bcf/d of transportation capacity through joint venture interests.

Rover Pipeline, completed and available for full commercial operation since November 2018, is a new 713-mile system 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 and into Canada.

ETO's vast interstate natural gas network spans the United States from Florida to California and Texas to Michigan, offering a comprehensive array of pipeline and storage services. Our pipelines have the capability to transport natural gas from nearly all Lower 48 onshore and offshore supply basins to customers in the Southeast, Gulf Coast, Southwest, Midwest, Northeast and Canada. Through numerous interconnections with other pipelines, our interstate systems can access virtually any supply or market in the country. As discussed further herein, our interstate segment operations are regulated by the FERC, which has broad regulatory authority over the business and operations of interstate natural gas pipelines.

Lake Charles LNG, our wholly-owned subsidiary, owns an LNG import terminal and regasification facility located on Louisiana's Gulf Coast near Lake Charles, Louisiana. The import terminal has approximately 9.0 Bcf of above ground storage capacity and the regasification facility has a send out capacity of 1.8 Bcf/d. Lake Charles LNG derives all of its revenue from a series of long-term contracts with a wholly-owned subsidiary of Shell.

LCL, our wholly-owned subsidiary, is currently developing a natural gas liquefaction facility for the export of LNG. In December 2015, Lake Charles LNG received authorization from the FERC to site, construct and operate facilities for the liquefaction and export of natural gas. The project would utilize existing dock and storage facilities owned by Lake Charles LNG located on the Lake Charles site.

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 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. Gathering systems generally consist of a network of small diameter pipelines and, if necessary, compression systems, that collect natural gas from points near producing wells and transports it to larger pipelines for further transportation.

Treating plants remove carbon dioxide and hydrogen sulfide from natural gas that is higher in carbon dioxide, hydrogen sulfide or certain other contaminants, to ensure that it meets pipeline quality specifications. Natural gas processing involves the separation of natural gas into pipeline quality natural gas, or residue gas, and a mixed NGL stream. 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 can be processed to take advantage of favorable margins for NGLs extracted from the gas stream.

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Through our midstream segment, we own and operate natural gas gathering and NGL pipelines, natural gas processing plants, natural gas treating facilities and natural gas conditioning facilities with an aggregate processing capacity of approximately 7.9 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 in South Texas, West Texas, New Mexico, North Texas, East Texas, West Virginia, Pennsylvania, Ohio and Louisiana. Many of our midstream assets are integrated with our intrastate transportation and storage assets.

Our midstream segment also includes a 60% interest in Edwards Lime Gathering, LLC, which operates natural gas gathering, oil pipeline and oil stabilization facilities in South Texas and a 75% membership interest in ORS, which operates a natural gas gathering system in the Utica shale in Ohio.

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.

Our NGL and refined products transportation and services segment includes:

- approximately 4,769 miles of NGL pipelines;
- NGL and propane fractionation facilities with an aggregate capacity of 825 MBbls/d;
- NGL storage facility in Mont Belvieu with a working storage capacity of approximately 45 million Bbls; and
- other NGL storage assets, located at our Cedar Bayou and Hattiesburg storage facilities, and our Nederland, Marcus Hook and Inkster NGL terminals with an aggregate storage capacity of approximately 11 million Bbls.

We are currently constructing a seventh fractionator at our Mont Belvieu facility, which we expect to be operational in the first quarter of 2020. In addition, we are constructing an expansion to the Lone Star Express pipeline, which is expected to be in service early in the fourth quarter of 2020. The NGL pipelines primarily transport NGLs from the Permian and Delaware basins and the Barnett and Eagle Ford Shales to Mont Belvieu.

NGL terminalling services are facilitated by approximately 7 million Bbls of NGL storage capacity. These operations also support our liquids blending activities, including the use of our patented butane blending technology. Refined products operations provide transportation and terminalling services through the use of approximately 2,203 miles of refined products pipelines and approximately 35 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 utilize our integrated pipeline and terminalling assets, as well as acquisition and marketing activities, to service refined products markets in several regions throughout the United States.

Revenues in this segment are 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. Fees are market-based, negotiated with customers and competitive with regional regulated pipelines and fractionators. Storage revenues are derived from base storage and throughput fees. This segment also derives revenues from the marketing of NGLs and processing and fractionating refinery off-gas.

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. Through our crude oil transportation and services segment, we own and operate (through wholly-owned subsidiaries or joint venture interests) approximately 9,524 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States. This segment includes equity ownership interests in two crude oil pipelines, the Bakken Pipeline system and Bayou Bridge Pipeline. Our crude oil terminalling services operate with an aggregate storage capacity of approximately 38 million Bbls, including approximately 28 million Bbls at our Gulf Coast terminal in Nederland, Texas and approximately 4 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 midcontinent 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. 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.

Investment in Sunoco LP

Sunoco LP is engaged in the distribution of motor fuels to independent dealers, distributors, and other commercial customers and the distribution of motor fuels to end-user customers at retail sites operated by commission agents. Additionally, it receives rental income through the leasing or subleasing of real estate used in the retail distribution of motor fuel. Sunoco LP also operates 75 retail stores located in Hawaii and New Jersey.

Sunoco LP is a distributor of motor fuels and other petroleum products which Sunoco LP supplies to third-party dealers and distributors, to independent operators of commission agent locations and other commercial consumers of motor fuel. Also included in the wholesale operations are transmix processing plants and refined products terminals. Transmix is the mixture of various refined products (primarily gasoline and diesel) created in the supply chain (primarily in pipelines and terminals) when various products interface with each other. Transmix processing plants separate this mixture and return it to salable products of gasoline and diesel.

Sunoco LP is the exclusive wholesale supplier of the iconic Sunoco-branded motor fuel, supplying an extensive distribution network of approximately 5,293 Sunoco-branded company and third-party operated locations throughout the East Coast, Midwest, South Central and Southeast regions of the United States. Sunoco LP believes it is one of the largest independent motor fuel distributors of Chevron, Exxon and Valero branded motor fuel in the United States. In addition to distributing motor fuels, Sunoco LP also distributes other petroleum products such as propane and lubricating oil, and Sunoco LP receives rental income from real estate that it leases or subleases.

Sunoco LP operations primarily consist of fuel distribution and marketing.

Investment in USAC

USAC provides compression services throughout the United States, including the Utica, Marcellus, Permian Basin, Delaware Basin, Eagle Ford, Mississippi Lime, Granite Wash, Woodford, Barnett, Haynesville, Niobrara and Fayetteville shales. USAC provides compression services to its customers primarily in connection with infrastructure applications, including both allowing for the processing and transportation of natural gas through the domestic pipeline system and enhancing crude oil production through artificial lift processes. As such, USAC’s compression services play a critical role in the production, processing and transportation of both natural gas and crude oil.

USAC operates a modern fleet of compression units, with an average age of approximately five years. USAC’s standard new-build compression units are generally configured for multiple compression stages allowing USAC to operate its units across a broad range of operating conditions. As part of USAC’s services, it engineers, designs, operates, services and repairs its compression units and maintains related support inventory and equipment.

USAC provides compression services to its customers under fixed-fee contracts with initial contract terms typically between six months and five years, depending on the application and location of the compression unit. USAC typically continues to provide compression services at a specific location beyond the initial contract term, either through contract renewal or on a month-to-month or longer basis. USAC primarily enters into take-or-pay contracts whereby its customers are required to pay a monthly fee even during periods of limited or disrupted throughput, which enhances the stability and predictability of its cash flows. USAC is not directly exposed to commodity price risk because it does not take title to the natural gas or crude oil involved in its services and because the natural gas used as fuel by its compression units is supplied by its customers without cost to USAC.

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USAC's assets and operations are all located and conducted in the United States.

As of December 31, 2018, USAC had 3,597,097 horsepower in its fleet and 131,750 horsepower on order for expected delivery during 2019.

All Other Segment

Operations below the quantitative thresholds are classified as "All other." These include the following:

- Our approximately 8% non-operating interest in PES, which owns a refinery in Philadelphia.
- Our 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.
- Our natural gas compression equipment business which has operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas.
- Our wholly-owned subsidiary, Dual Drive Technologies, Ltd. ("DDT"), which provides compression services to customers engaged in the transportation of natural gas, including our other segments.
- Our subsidiaries 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.
- PEI Power LLC 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	%	3,150	5.2	11.2
Oasis Pipeline (1)	100	%	750	2.0	—
HPL System	100	%	3,920	5.3	52.5
ETC Katy Pipeline	100	%	460	2.4	—
Regency Intrastate Gas	100	%	450	2.1	—
Comanche Trail Pipeline	16	%	195	1.1	—
Trans-Pecos Pipeline	16	%	143	1.4	—
Old Ocean Pipeline, LLC	50	%	240	0.2	—
Red Bluff Express Pipeline	70	%	100	1.4	—

(1) Includes bi-directional capabilities

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

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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 Pecos, Texas, the Maypearl Hub in Central Texas and the Carthage Hub in East 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 1.3 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 gathering system known as the 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 gathered 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, Beaumont 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, Carthage 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, 2018, we had approximately 12.8 Bcf committed under fee-based arrangements with third parties and approximately 18.7 Bcf stored in the facility for our own account.

- The ETC Katy Pipeline connects three treating facilities, one of which we own, with our gathering system known as Southeast Texas System. The ETC Katy pipeline serves producers in East and North Central Texas and provided access to the Katy Hub. The ETC Katy 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.
- Comanche Trail is a 195-mile intrastate pipeline that delivers natural gas from the Waha Hub near Pecos, 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 Pecos, Texas to the United States/Mexico border near Presidio, Texas. The Partnership owns a 16% membership interest in and operates Trans-Pecos.
- Old Ocean is a 240-mile intrastate pipeline system that delivers natural gas from Ellis County, Texas to Brazoria County, Texas. The Partnership owns a 50% membership interest in and operates Old Ocean.
- The Red Bluff Express Pipeline is an approximately 100-mile intrastate pipeline that runs through the heart of the Delaware basin and connects our Orla Plant, as well as third-party plants to the Waha Oasis Header. An expansion of the Red Bluff Express Pipeline is expected to be in service in the second half of 2019. The Partnership owns a 70% membership interest in and operates Red Bluff Express.

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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	50	%	5,344	3.4	—
Transwestern Pipeline	100	%	2,614	2.1	—
Panhandle Eastern Pipe Line [1]	100	%	6,402	2.8	73.4
Trunkline Gas Company	100	%	2,231	0.9	13.0
Tiger Pipeline	100	%	197	2.4	—
Fayetteville Express Pipeline	50	%	185	2.0	—
Sea Robin Pipeline	100	%	785	2.0	—
Rover Pipeline	32.6	%	713	3.25	—
Midcontinent Express Pipeline	50	%	512	1.8	—
Gulf States	100	%	10	0.1	—

[1] Natural gas storage assets are owned by Pan Gas Storage LLC (d.b.a Southwest Gas Storage Company).

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

- Florida Gas Transmission Pipeline ("FGT") has mainline capacity of 3.4 Bcf/d and approximately 5,344 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 60% of the natural gas consumed in the state. In addition, FGT's system operates and maintains multiple 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, industrial end-users and local distribution companies. FGT is owned by Citrus, a 50/50 joint venture with KMI.
- Transwestern Pipeline transports natural gas supply from 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. The system has bi-directional capabilities and can access Texas and midcontinent connecting pipelines and natural gas market hubs, as well as major western markets in Arizona, Nevada and California. Transwestern's customers include local distribution companies, producers, marketers, electric power generators and industrial end-users.
- 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. Panhandle contracts for over 73 Bcf of natural gas storage.
- Trunkline Gas Company'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. Trunkline has one natural gas storage field located in Louisiana.
- Tiger Pipeline is a bi-directional system that extends through the heart of the Haynesville Shale and ends near Delhi, Louisiana, with interconnects to multiple interstate pipelines.
- Fayetteville Express Pipeline originates near Conway County, Arkansas and continues eastward to Panola County, Mississippi with multiple pipeline interconnections along the route. Fayetteville Express Pipeline is owned by a 50/50 joint venture with KMI.
- Sea Robin Pipeline's system consists of two offshore Louisiana natural gas supply pipelines extending 120 miles into the Gulf of Mexico.
- Rover Pipeline is a large diameter pipeline with total capacity to transport 3.25 Bcf/d natural gas from processing plants in West Virginia, Eastern Ohio and Western Pennsylvania for delivery to other pipeline interconnects in Ohio

and Michigan, where the gas is delivered for distribution to markets across the United States, as well as to Ontario, Canada.

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- Midcontinent Express Pipeline originates near Bennington, Oklahoma and traverses 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, the operator of the system.
- Gulf States Transmission is a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

Regasification Facility

Lake Charles LNG, our wholly-owned subsidiary, owns a LNG import terminal and regasification facility located on Louisiana's Gulf Coast near Lake Charles, Louisiana. The import terminal has approximately 9.0 Bcf of above ground LNG storage capacity and the regasification facility has a send out capacity of 1.8 Bcf/d.

Liquefaction Project

LCL, our wholly-owned subsidiary, is in the process of developing an LNG liquefaction project at the site of our Lake Charles LNG import terminal and regasification facility. The liquefaction facility 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 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. On June 18, 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. LCL and Shell are actively involved in a variety of activities related to the development of the project. LCL has also been marketing LNG offtake to numerous potential customers in Asia and Europe.

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. In addition, LCL received its 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.

Midstream

The following details our assets in the midstream segment:

Description of Assets	Net Gas Processing Capacity (MMcf/d)
South Texas Region:	
Southeast Texas System	410
Eagle Ford System	1,920
Ark-La-Tex Region	1,442
North Central Texas Region	700
Permian Region	2,340
Midcontinent Region	860
Eastern Region	200

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 ETC Katy Pipeline and is also connected to the Oasis Pipeline. The Southeast Texas System includes two natural gas processing plants (La Grange and Alamo) with aggregate capacity of 410 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

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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. 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 870 MMcf/d.
- 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, a 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 an NGL pipeline that provides connections to the Mont Belvieu market for NGLs produced from our processing plants. Collectively, the ten natural gas processing facilities (Dubach, Dubberly, Lisbon, Salem, Elm Grove, Minden, Ada, Brookeland, Lincoln Parish and Mt. Olive) have an aggregate capacity of 1.3 Bcf/d.
- Through the gathering and processing systems described above and their interconnections with RIGS in north Louisiana, as well as other pipelines, 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 700 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 midcontinent 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 eleven processing facilities (Waha, Coyanosa, Red Bluff, Halley, Jal, Keyston, Tippet, Orla, Panther, Rebel and Arrowhead) with an aggregate processing capacity of 2.02 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 50% 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.

Midcontinent Region:

- The Midcontinent 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 Midcontinent assets are extensive systems that gather, compress and dehydrate low-pressure gas. The Midcontinent 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 860 MMcf/d.

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- We operate our Midcontinent 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 eleven counties in Pennsylvania, four counties in Ohio, three counties in West Virginia, and gather natural gas from the Marcellus and Utica basins. Our Eastern Region assets include approximately 600 miles of natural gas gathering pipeline, natural gas trunklines, fresh-water pipelines, and nine gathering and processing systems, as well as the 200 MMcf/d Revolution processing plant, which feeds into our Mariner East and Rover pipeline systems.
- We also own a 51% membership interest in Aqua – ETC Water Solutions LLC, a joint venture that transports and supplies fresh water to natural gas producers drilling in the Marcellus Shale in Pennsylvania.
- We own a 75% membership interest in ORS. On behalf of ORS, we operate its Ohio Utica River System, which consists of 47 miles of 36-inch, 13 miles of 30-inch and 3 miles of 24-inch gathering trunklines, that delivers up to 3.6 Bcf/d to Rockies Express Pipeline, Texas Eastern Transmission, Leach Xpress, Rover and DEO TPL-18.

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	670	345	—	—
Mariner South	97	200	—	—
Mariner West	395	50	—	—
Other NGL Pipelines	943	591	—	—
Liquids Fractionation and Services Facilities:				
Mont Belvieu Facilities	163	42	790	45,500
Sea Robin Processing Plant[(1)]	—	—	26	—
Refinery Services[(1)]	103	—	35	—
Hattiesburg Storage Facilities	—	—	—	3,000
Cedar Bayou	—	—	—	1,600
NGL Terminals:				
Nederland	—	—	—	1,200
Marcus Hook Industrial Complex	—	—	132	5,000
Inkster	—	—	—	800
Refined Products Pipelines	2,203	800	—	—
Refined Products Terminals:				
Eagle Point	—	—	—	6,000
Marcus Hook Industrial Complex	—	—	—	1,000
Marcus Hook Tank Farm	—	—	—	2,000
Marketing Terminals	—	—	—	8,000

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(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. An expansion of the pipeline is currently underway, which will add approximately 400 MBbls/d of NGL pipeline capacity from Lone Star's pipeline system near Wink, Texas to the Lone Star Express 30-inch pipeline south of Fort Worth, Texas. It is expected to be in service by the fourth quarter of 2020.
- 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, began service in December 2018.
- The Mariner South liquids pipeline delivers 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.
- Refined products pipelines include approximately 2,203 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 46 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 VI was placed in service in February 2019, Fractionator VII is currently under construction and is scheduled to be operational by the first quarter of 2020.
- 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 Cedar Bayou storage facility is an integrated liquids storage facility with approximately 1.6 million Bbls of tank storage, generating revenues from fixed fee storage contracts, throughput fees, and revenue from blending butane into refined gasoline.

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- 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 NGL storage and terminalling services to both affiliates and third-party customers, the Marcus Hook Industrial Complex currently serves as an off-take outlet for our Mariner East 1 pipeline system.
- The Inkster terminal, located near Detroit, Michigan, consists of multiple salt caverns with a total storage capacity of approximately 800 MBbls 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 35 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 ETC Sunoco Holdings LLC (“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 561 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 183 miles of various diameters refined products pipeline in New Jersey (including 80 miles of the 16-inch diameter Harbor Pipeline).
- The midcontinent refined products pipelines primarily consists of approximately 294 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 375 miles of 8-inch diameter refined products pipeline.
- The Inland refined products pipeline, approximately 486 miles of pipeline in Ohio, consists of 72 miles of 12-inch diameter refined products pipeline in Northwest Ohio, 135 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 and 6-inch diameter pipeline in Northeast Ohio.
- This segment also includes the following joint ventures: 15% membership interest in the Explorer Pipeline Company, a 1,850-mile pipeline which originates from refining centers in Beaumont, Port Arthur, and Houston, Texas and extends to Chicago, Illinois; 31% membership interest in the Wolverine Pipe Line Company, a 700-mile pipeline that originates from Chicago, Illinois and extends to Detroit, Grand Haven, and Bay City, Michigan; 17% membership interest in the West Shore Pipe Line Company, a 650-mile pipeline

which originates in Chicago, Illinois and extends to Madison and Green Bay, Wisconsin; and a 14% membership interest in the Yellowstone Pipe Line Company, a 700-mile pipeline which originates from Billings, Montana and extends to Moses Lake, Washington.

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Crude Oil Transportation and Services

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

Description of Assets	Ownership Interest		Miles of Crude Pipeline (1)	Working Storage Capacity (MBbls)
Dakota Access Pipeline	36.4	%	1,158	—
Energy Transfer Crude Oil Pipeline	36.4	%	760	—
Bayou Bridge Pipeline	60	%	49	—
Permian Express Pipelines	87.7	%	1,712	—
Other Crude Oil Pipelines	100	%	5,845	—
Nederland Terminal	100	%	—	28,000
Fort Mifflin Terminal	100	%	—	3,570
Eagle Point Terminal	100	%	—	1,000
Midland Terminal	100	%	—	2,000
Marcus Hook Industrial Complex	100	%	—	1,000
Patoka, Illinois Terminal	87.7	%	—	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 9,524 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, and 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 1,918 mile pipeline with capacity of 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 1,158 miles of 12, 20, 24 and 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 approximately 691 miles of mostly 30-inch converted natural gas pipeline and 69 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 ETO and Phillips 66, in which ETO 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, with commercial operations expected to begin in March 2019.

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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 Express 3, which became fully operational in September 2018, Permian Longview and Louisiana Access pipelines, as well as the Longview to Louisiana and Nederland Access 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, petrochemicals and bunker oils (used for fueling ships and other marine vessels). The terminal currently has a total storage capacity of approximately 28 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 three 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.

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- 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.

Investment in Sunoco LP

Sunoco LP is a distributor of motor fuels and other petroleum products which Sunoco LP supplies to third-party dealers and distributors, to independent operators of commission agent locations and other commercial consumers of motor fuel. Also included in the wholesale operations are transmix processing plants and refined products terminals. Transmix is the mixture of various refined products (primarily gasoline and diesel) created in the supply chain (primarily in pipelines and terminals) when various products interface with each other. Transmix processing plants separate this mixture and return it to salable products of gasoline and diesel.

Sunoco LP is the exclusive wholesale supplier of the iconic Sunoco-branded motor fuel, supplying an extensive distribution network of approximately 5,293 Sunoco-branded company and third-party operated locations throughout the East Coast, Midwest, South Central and Southeast regions of the United States. Sunoco LP believes it is one of the largest independent motor fuel distributors of Chevron, Exxon and Valero branded motor fuel in the United States. In addition to distributing motor fuels, Sunoco LP also distributes other petroleum products such as propane and lubricating oil, and Sunoco LP receives rental income from real estate that it leases or subleases.

Sunoco LP operations primarily consist of fuel distribution and marketing.

Sunoco LP’s Fuel Distribution and Marketing Operations

Sunoco LP’s fuel distribution and marketing operations are conducted by the following consolidated subsidiaries:

- Sunoco, LLC (“Sunoco LLC”), a Delaware limited liability company, primarily distributes motor fuel in 30 states throughout the East Coast, Midwest, South Central and Southeast regions of the United States. Sunoco LLC also processes transmix and distributes refined product through its terminals in Alabama, Texas, Arkansas and New York;
- Sunoco Retail LLC (“Sunoco Retail”), a Pennsylvania limited liability company, owns and operates retail stores that sell motor fuel and merchandise primarily in New Jersey;
- Aloha Petroleum LLC, a Delaware limited liability company, distributes motor fuel and operates terminal facilities on the Hawaiian Islands; and
- Aloha Petroleum, Ltd. (“Aloha”), a Hawaii corporation, owns and operates retail stores on the Hawaiian Islands.

Sunoco LP purchases motor fuel primarily from independent refiners and major oil companies and distributes it across more than 30 states throughout the East Coast, Midwest, South Central and Southeast regions of the United States, as well as Hawaii to approximately:

- 75 company owned and operated retail stores;

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- 554 independently operated consignment locations where Sunoco LP sells motor fuel to customers under commission agent arrangements with such operators;
- 6,741 convenience stores and retail fuel outlets operated by independent operators, which are referred to as “dealers” or “distributors,” pursuant to long-term distribution agreements; and
- 2,714 other commercial customers, including unbranded convenience stores, other fuel distributors, school districts and municipalities and other industrial customers.

Sunoco LP’s Other Operations

Sunoco LP’s other operations include retail operations in Hawaii and New Jersey, credit card services, franchise royalties, as well as an ethanol plant that Sunoco LP recently entered into an agreement to divest.

Investment in USAC

The following details the assets of USAC:

USAC’s modern, standardized compression unit fleet is powered primarily by the Caterpillar, Inc.’s 3400, 3500 and 3600 engine classes, which range from 401 to 5,000 horsepower per unit. These larger horsepower units, which USAC defines as 400 horsepower per unit or greater, represented 85.8% of its total fleet horsepower (including compression units on order) as of December 31, 2018. In addition, a portion of its fleet consists of smaller horsepower units ranging from 40 horsepower to 399 horsepower that are primarily used in gas lift applications.

The following table provides a summary of USAC’s compression units by horsepower as of December 31, 2018:

Unit Horsepower	Fleet Horsepower	Number of Units	Horsepower on Order [(1)]	Number of Units on Order	Total Horsepower	Total Number of Units
Small horsepower						
<400	528,084	3,101	900	4	528,984	3,105
Large horsepower						
>400 and <1,000	429,203	735	—	—	429,203	735
>1,000	2,639,810	1,650	130,850	55	2,770,660	1,705
Total large horsepower	3,069,013	2,385	130,850	55	3,199,863	2,440
Total horsepower	3,597,097	5,486	131,750	59	3,728,847	5,545

(1) As of December 31, 2018, USAC had 131,750 horsepower on order for delivery during 2019.

All Other

The following details our assets in the all other segment.

PES

We have a non-controlling interest in PES, currently comprising approximately 8% of PES’ outstanding common shares. PES owns a refinery in Philadelphia.

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 DDT, which provides compression services to customers engaged in the transportation of natural gas, including our subsidiaries in other segments.

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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, 2018, we owned or controlled approximately 761 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.

Business Strategy

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 limited partnership. 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 and gas 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 and gas 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

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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 safest, 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.

Wholesale Fuel Distribution and Retail Marketing

In our wholesale fuel distribution business, we compete primarily with other independent motor fuel distributors. The markets for distribution of wholesale motor fuel and the large and growing convenience store industry are highly competitive and fragmented, which results in narrow margins. We have numerous competitors, some of which may have significantly greater resources and name recognition than we do. Significant competitive factors include the availability of major brands, customer service, price, range of services offered and quality of service, among others. We rely on our ability to provide value-added and reliable service and to control our operating costs in order to maintain our margins and competitive position.

In our retail business, we face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations of large integrated oil companies, independent gasoline service stations, convenience stores, fast food stores, supermarkets, drugstores, dollar stores, club stores and other similar retail outlets, some of which are well-recognized national or regional retail systems. The number of competitors varies depending on the geographical area. It also varies with gasoline and convenience store offerings. The principal competitive factors affecting our retail marketing operations include gasoline and diesel acquisition costs, site location, product price, selection and quality, site appearance and cleanliness, hours of operation, store safety, customer loyalty and brand recognition. We compete by pricing gasoline competitively, combining our retail gasoline business with convenience stores that provide a wide variety of products, and using advertising and promotional campaigns.

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 industrial end-users, 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

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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, 2018, 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, Rover, 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 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 in excess of $1.1 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.

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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 are subject to state statutes and regulations which could impose additional environmental, safety and operational requirements relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL transportation systems. In some jurisdictions, state public utility commission oversight may include the possibility of fines, penalties and delays in construction related to these regulations. In addition, the rates, terms and conditions of service 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.

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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 July 2016, the United States Court of Appeals for the District of Columbia Circuit issued an opinion in United Airlines, Inc., et al. v. FERC, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a master limited partnership, or MLP, to include an income tax allowance in the cost of service underlying its rates, in addition to the discounted cash flow return on equity, would not result in the pipeline partnership owners double recovering their income

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taxes. The court vacated FERC's order and remanded to FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. 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 in April 2017.

In March 2018, FERC issued a Revised Policy Statement on Treatment of Income Taxes in which FERC found that an impermissible double recovery results from granting an MLP pipeline both an income tax allowance and a return on equity pursuant to FERC's discounted cash flow methodology. FERC revised its previous policy, stating that it would no longer permit an MLP pipeline to recover an income tax allowance in its cost of service. FERC stated it will address the application of the United Airlines decision to non-MLP partnership forms as those issues arise in subsequent proceedings. Further, FERC stated that it will incorporate the effects of the post-United Airlines policy changes and the Tax Cuts and Jobs Act of 2017 on industry-wide crude oil pipeline costs in the 2020 five-year review of the crude oil pipeline index level. FERC will also apply the revised Policy Statement and the Tax Cuts and Jobs Act of 2017 to initial crude oil pipeline cost-of-service rates and cost-of-service rate changes on a going-forward basis under FERC's existing ratemaking policies, including cost-of-service rate proceedings resulting from shipper-initiated complaints. In July 2018, FERC dismissed requests for rehearing and clarification of the March 2018 Revised Policy Statement, but provided further guidance, clarifying that a pass-through entity will not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double recovery of investors' income tax costs.

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, and as discussed immediately above, 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 in March 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. FERC extended the time frame to respond to such requests in January 2018, but has not yet taken final action. 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 Pennsylvania Public Utility Commission 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. In November 2018, PHMSA issued a final rule increasing those maximum civil penalties to $213,268 per day, with a maximum of $2,132,679 for a series of violations. The 2016 Pipeline Safety Act extended PHMSA’s statutory mandate through 2019 and, among other things, require PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and develop new safety standards for natural gas storage facilities, which is expected to be finalized in 2019. 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, but is expected to do so in 2019.

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. A final rulemaking is expected in 2019. 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 TRRC, 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 refined 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, 2018 and 2017, accruals of $337 million and $372 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 $263 million and $284 million at December 31, 2018 and 2017, 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, 2018, the captive insurance company held $183 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. The Partnership's consolidated balance sheet reflected $337 million in environmental accruals as of December 31, 2018.

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." In April 2018 and July 2018, the EPA issued area designations for all areas not addressed in the November 2017 rule. States with moderate or high nonattainment areas must submit state implementation plans to the EPA by October 2021. 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 ("USACE") 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 USACE 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. In January 2018, the United States Supreme Court issued a decision finding that jurisdiction resides with the federal district courts. Also in January 2018, the EPA and USACE finalized a rule that would delay applicability of the rule to two years from the rule's publication in the Federal Register. The EPA and USACE formally proposed a rule revising the definition of "waters of the United States" in December 2018. The proposed definition would substantially reduce the scope of waters that fall within the Clean Water Act's jurisdiction, in part by excluding ephemeral streams. The EPA and USACE had previously determined that ephemeral streams could potentially qualify as "waters of the United States," which would not be possible under the proposed definition. As a result of these developments, future implementation of the June 2015 rule or any replacement 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

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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 greenhouse gases ("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 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. In September 2018, the EPA proposed amendments to Subpart OOOOa that would reduce the 2016 standards' fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other changes. Various industry and environmental groups have separately challenged both the original 2016 standards and the EPA's attempts to delay the implementation of the rule. 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

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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, 2018, ETO and its consolidated subsidiaries employed an aggregate of 11,768 persons, 1,434 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. 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 our Series A Preferred Units, Series B Preferred Units, Series C Preferred Units and Series D Preferred Units and our common unitholder, ET (collectively, “Unitholders”) depends upon the amount of cash we generate from our operations and from our subsidiaries, Sunoco LP and USAC. 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;

- 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;

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- the relationship between natural gas, NGL and crude oil prices;
- 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 and our subsidiaries, including Sunoco LP and USAC, 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 holders of our Unitholders.

Furthermore, our 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.

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

The partnership agreements of Sunoco LP and USAC allow each partnership to issue an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by each respective partnership will have the following effects:

- Unitholders' current proportionate ownership interest in each partnership 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 each partnership's common units may decline.

The payment of distributions on any additional units issued by Sunoco LP and USAC may increase the risk that either partnership 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.

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, 2018, we had approximately $40.51 billion of consolidated debt, excluding the debt of our unconsolidated 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 $8.54 billion of our consolidated debt as of December 31, 2018 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.

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 ET as the indirect owner of our General Partner, may be factors in credit evaluations of us due to the significant influence of our General Partner and ET 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.

ET 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 ET 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 (ET 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.

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;

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- 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.

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.

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.

A reduction in Sunoco LP’s distributions will disproportionately affect the amount of cash distributions to which ETO is entitled.

ETO indirectly owns all of the IDRs of Sunoco LP. These IDRs entitle the holder to receive increasing percentages of total cash distributions made by Sunoco LP as such entity reaches established target cash distribution levels as specified in its partnership agreement. ETO currently receives its pro rata share of cash distributions from Sunoco LP based on the highest sharing level of 50% in respect of the Sunoco LP IDRs.

A decrease in the amount of distributions by Sunoco LP to less than $0.6563 per unit per quarter would reduce ETO’s percentage of the incremental cash distributions from Sunoco LP above $0.5469 per unit per quarter from 50% to 25%. As a result, any such reduction in quarterly cash distributions from Sunoco LP would have the effect of disproportionately reducing the amount of all distributions that ETO receives, based on its ownership interest in the IDRs as compared to cash distributions received from its Sunoco LP common units.

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 preferred unitholders; 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

Although we control Sunoco LP and USAC through our ownership of Sunoco LP's and USAC's general partners, Sunoco LP's and USAC's general partners owe fiduciary duties to Sunoco LP and Sunoco LP's unitholders and USAC and USAC's unitholders, respectively, which may conflict with our interests.

Conflicts of interest exist and may arise in the future as a result of the relationships between us and our affiliates, on the one hand, and Sunoco LP and USAC and their respective limited partners, on the other hand. The directors and officers of Sunoco LP's and USAC's general partners have fiduciary duties to manage Sunoco LP and USAC, respectively, in a manner beneficial to us. At the same time, the general partners have fiduciary duties to manage Sunoco LP and USAC in a manner beneficial to Sunoco LP and USAC and their respective limited partners. The boards of directors of Sunoco LP's and USAC's general partner will resolve any such conflict and have broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest.

For example, conflicts of interest with Sunoco LP and USAC may arise in the following situations:

- the allocation of shared overhead expenses to Sunoco LP, USAC and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and Sunoco LP and USAC, on the other hand;
- the determination of the amount of cash to be distributed to Sunoco LP's and USAC's partners and the amount of cash to be reserved for the future conduct of Sunoco LP's and USAC's businesses;

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- the determination whether to make borrowings under Sunoco LP's and USAC's revolving credit facilities to pay distributions to their respective partners;
- the determination of whether a business opportunity (such as a commercial development opportunity or an acquisition) that we may become aware of independently of Sunoco LP and USAC is made available for Sunoco LP and USAC to pursue; and
- any decision we make in the future to engage in business activities independent of Sunoco LP and USAC.

The fiduciary duties of our General Partner's officers and directors may conflict with those of Sunoco LP's or USAC's respective general partners.

Conflicts of interest may arise because of the relationships among Sunoco LP, USAC, their general partners and us. Our General Partner's directors and officers have fiduciary duties to manage our business in a manner beneficial to us and our Unitholders. Some of our General Partner's directors or officers are also directors and/or officers of Sunoco LP's general partner or USAC's general partner, and have fiduciary duties to manage the respective businesses of Sunoco LP and USAC in a manner beneficial to Sunoco LP, USAC and their respective Unitholders. The resolution of these conflicts may not always be in our best interest or that of our Unitholders.

Potential conflicts of interest may arise among our General Partner, its affiliates and us. Our General Partner and its affiliates have limited fiduciary duties to us, which may permit them to favor their own interests to the detriment of us.

Conflicts of interest may arise among our General Partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our General Partner may favor its own interests and the interests of its affiliates over our interests. These conflicts include, among others, the following:

- our General Partner is allowed to take into account the interests of parties other than us, including Sunoco LP and USAC, and their respective affiliates and any general partners and limited partnerships acquired in the future, in resolving conflicts of interest, which has the effect of limiting its fiduciary duties to us.
- our General Partner has limited its liability and reduced its fiduciary duties under the terms of our partnership agreement, while also restricting the remedies available for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing our units, Unitholders consent to various actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.
- our General Partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution.
- our General Partner determines which costs it and its affiliates have incurred are reimbursable by us.
- our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to us.
- our General Partner controls the enforcement of obligations owed to us by it and its affiliates.
- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

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 ET. 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 ET. 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.

ET 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 ET, 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 ET as its sole owner. As a result of these conflicts of interest, our General Partner may favor its own interest or those of ET 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 ET, in resolving conflicts of interest, thereby limiting its fiduciary duties to us.

- our General Partner’s affiliates, including ET, are not prohibited from engaging in other businesses or activities, including those in direct competition with us.

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- 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 ET.
- neither our partnership agreement nor any other agreement requires ET or its affiliates to pursue a business strategy that favors us. The directors and officers of the general partners of ET 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 ET who provide advice to us also may devote significant time to the businesses of ET 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 and our subsidiaries, including Sunoco LP and USAC, 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, Sunoco LP's and USAC's 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, Sunoco LP and USAC are subject to risks of loss resulting from nonpayment or nonperformance by our, Sunoco LP's and USAC's customers. Commodity price volatility and/or 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, Sunoco LP's and USAC's results of operations and operating cash flows.

We compete with other businesses in our market with respect to attracting and retaining qualified employees.

Our continued success depends on our ability to attract and retain qualified personnel in all areas of our business. We compete with other businesses in our market with respect to attracting and retaining qualified employees. A tight labor market, increased overtime and a higher full-time employee ratio may cause labor costs to increase. A shortage of qualified employees may require us to enhance wage and benefits packages in order to compete effectively in the hiring and retention of such employees or to hire more expensive temporary employees. No assurance can be given that our labor costs will not increase, or that such increases can be recovered through increased prices charged to customers. We are especially vulnerable to labor shortages in oil and gas drilling areas when energy prices drive higher exploration and production activity.

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, crude oil and refined products that are beyond our control.

The prices for natural gas, NGLs, crude oil and refined 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 crude oil, refined products, 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 crude oil, refined products, 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 refined products transported through our crude oil and refined products 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 refined products supplied from or delivered to any of these areas could materially reduce demand for crude oil or refined products in these areas. In either case, the volumes of crude oil or refined products transported in our crude oil and refined products 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 provide services related to natural gas wells that experience production declines over time, which we may not be able to replace with natural gas production from newly drilled wells in the same natural gas basins or in other new natural gas producing areas.

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

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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, 2018, 2017 and 2016, gross margin from our midstream segment totaled $2.38 billion, $2.18 billion and $1.80 billion, respectively, of which fee-based revenues constituted 76%, 77% and 86%, respectively, and non-fee based margin constituted 24%, 23% and 14%, 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.

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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.

A significant decrease in demand for motor fuel, including increased consumer preference for alternative motor fuels or improvements in fuel efficiency, in the areas Sunoco LP serves would reduce their ability to make distributions to unitholders.

Sales of refined motor fuels account for approximately 97% of Sunoco LP’s total revenues and 71% of continuing operations gross profit. A significant decrease in demand for motor fuel in the areas Sunoco LP serves could significantly reduce revenues and Sunoco LP’s ability to make distributions to its unitholders. Sunoco LP revenues are dependent on various trends, such as trends in commercial truck traffic, travel and tourism in their areas of operation, and these trends can change. Regulatory action, including government imposed fuel efficiency standards, may also affect demand for motor fuel. Because certain of Sunoco LP’s operating costs and expenses are fixed and do not vary with the volumes of motor fuel distributed, their costs and expenses might not decrease ratably or at all should they experience such a reduction. As a result, Sunoco LP may experience declines in their profit margin if fuel distribution volumes decrease.

Any technological advancements, regulatory changes or changes in consumer preferences causing a significant shift toward alternative motor fuels could reduce demand for the conventional petroleum based motor fuels Sunoco LP currently sells. Additionally, a shift toward electric, hydrogen, natural gas or other alternative-power vehicles could fundamentally change customers' shopping habits or lead to new forms of fueling destinations or new competitive pressures.

New technologies have been developed and governmental mandates have been implemented to improve fuel efficiency, which may result in decreased demand for petroleum-based fuel. Any of these outcomes could result in fewer visits to Sunoco LP’s convenience stores or independently operated commission agents and dealer locations, a reduction in demand from their wholesale customers, decreases in both fuel and merchandise sales revenue, or reduced profit margins, any of which could have a material adverse effect on Sunoco LP’s business, financial condition, results of operations and cash available for distribution to unitholders.

The industries in which Sunoco LP operates are subject to seasonal trends, which may cause its operating costs to fluctuate, affecting its cash flow.

Sunoco LP relies in part on customer travel and spending patterns, and may experience more demand for gasoline in the late spring and summer months than during the fall and winter. Travel, recreation and construction are typically higher in these months in the geographic areas in which Sunoco LP or its commission agents and dealers operate, increasing the demand for motor fuel that

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they sell and distribute. Therefore, Sunoco LP's revenues and cash flows are typically higher in the second and third quarters of our fiscal year. As a result, Sunoco LP's results from operations may vary widely from period to period, affecting Sunoco LP's cash flow.

Sunoco LP's financial condition and results of operations are influenced by changes in the prices of motor fuel, which may adversely impact margins, customers' financial condition and the availability of trade credit.

Sunoco LP's operating results are influenced by prices for motor fuel. General economic and political conditions, acts of war or terrorism and instability in oil producing regions, particularly in the Middle East and South America, could significantly impact crude oil supplies and petroleum costs. Significant increases or high volatility in petroleum costs could impact consumer demand for motor fuel and convenience merchandise. Such volatility makes it difficult to predict the impact that future petroleum costs fluctuations may have on Sunoco LP's operating results and financial condition. Sunoco LP is subject to dealer tank wagon pricing structures at certain locations further contributing to margin volatility. A significant change in any of these factors could materially impact both wholesale and retail fuel margins, the volume of motor fuel distributed or sold at retail, and overall customer traffic, each of which in turn could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to unitholders.

Significant increases in wholesale motor fuel prices could impact Sunoco LP as some of their customers may have insufficient credit to purchase motor fuel from us at their historical volumes. Higher prices for motor fuel may also reduce access to trade credit support or cause it to become more expensive.

The dangers inherent in the storage and transportation of motor fuel could cause disruptions in Sunoco LP's operations and could expose them to potentially significant losses, costs or liabilities.

Sunoco LP stores motor fuel in underground and aboveground storage tanks. Sunoco LP transports the majority of its motor fuel in its own trucks, instead of by third-party carriers. Sunoco LP's operations are subject to significant hazards and risks inherent in transporting and storing motor fuel. These hazards and risks include, but are not limited to, traffic accidents, fires, explosions, spills, discharges, and other releases, any of which could result in distribution difficulties and disruptions, environmental pollution, governmentally-imposed fines or clean-up obligations, personal injury or wrongful death claims, and other damage to its properties and the properties of others. Any such event not covered by Sunoco LP's insurance could have a material adverse effect on its business, financial condition, results of operations and cash available for distribution to unitholders.

Sunoco LP's fuel storage terminals are subject to operational and business risks which may adversely affect their financial condition, results of operations, cash flows and ability to make distributions to unitholders.

Sunoco LP's fuel storage terminals are subject to operational and business risks, the most significant of which include the following:

- the inability to renew a ground lease for certain of their fuel storage terminals on similar terms or at all;
- the dependence on third parties to supply their fuel storage terminals;
- outages at their fuel storage terminals or interrupted operations due to weather-related or other natural causes;
- the threat that the nation's terminal infrastructure may be a future target of terrorist organizations;
- the volatility in the prices of the products stored at their fuel storage terminals and the resulting fluctuations in demand for storage services;
- the effects of a sustained recession or other adverse economic conditions;
- the possibility of federal and/or state regulations that may discourage their customers from storing gasoline, diesel fuel, ethanol and jet fuel at their fuel storage terminals or reduce the demand by consumers for petroleum products;
- competition from other fuel storage terminals that are able to supply their customers with comparable storage capacity at lower prices; and
- climate change legislation or regulations that restrict emissions of GHGs could result in increased operating and capital costs and reduced demand for our storage services.

The occurrence of any of the above situations, amongst others, may affect operations at their fuel storage terminals and may adversely affect Sunoco LP's business, financial condition, results of operations, cash flows and ability to make distributions to unitholders.

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Negative events or developments associated with Sunoco LP's branded suppliers could have an adverse impact on its revenues.

Sunoco LP believes that the success of its operations is dependent, in part, on the continuing favorable reputation, market value, and name recognition associated with the motor fuel brands sold at Sunoco LP's convenience stores and at stores operated by its independent, branded dealers and commission agents. Erosion of the value of those brands could have an adverse impact on the volumes of motor fuel Sunoco LP distributes, which in turn could have a material adverse effect on its business, financial condition, results of operations and ability to make distributions to its unitholders.

The wholesale motor fuel distribution industry and convenience store industry are characterized by intense competition and fragmentation and impacted by new entrants. Failure to effectively compete could result in lower margins.

The market for distribution of wholesale motor fuel is highly competitive and fragmented, which results in narrow margins. Sunoco LP has numerous competitors, some of which may have significantly greater resources and name recognition than it does. Sunoco LP relies on its ability to provide value-added, reliable services and to control its operating costs in order to maintain our margins and competitive position. If Sunoco LP fails to maintain the quality of its services, certain of its customers could choose alternative distribution sources and margins could decrease. While major integrated oil companies have generally continued to divest retail sites and the corresponding wholesale distribution to such sites, such major oil companies could shift from this strategy and decide to distribute their own products in direct competition with Sunoco LP, or large customers could attempt to buy directly from the major oil companies. The occurrence of any of these events could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to unitholders.

The geographic areas in which Sunoco LP operates and supplies independently operated commission agent and dealer locations are highly competitive and marked by ease of entry and constant change in the number and type of retailers offering products and services of the type we and our independently operated commission agents and dealers sell in stores. Sunoco LP competes with other convenience store chains, independently owned convenience stores, motor fuel stations, supermarkets, drugstores, discount stores, dollar stores, club stores, mass merchants and local restaurants. Over the past two decades, several non-traditional retailers, such as supermarkets, hypermarkets, club stores and mass merchants, have impacted the convenience store industry, particularly in the geographic areas in which Sunoco LP operates, by entering the motor fuel retail business. These non-traditional motor fuel retailers have captured a significant share of the motor fuels market, and Sunoco LP expects their market share will continue to grow.

In some of Sunoco LP's markets, its competitors have been in existence longer and have greater financial, marketing, and other resources than they or their independently operated commission agents and dealers do. As a result, Sunoco LP's competitors may be able to better respond to changes in the economy and new opportunities within the industry. To remain competitive, Sunoco LP must constantly analyze consumer preferences and competitors' offerings and prices to ensure that they offer a selection of convenience products and services at competitive prices to meet consumer demand. Sunoco LP must also maintain and upgrade our customer service levels, facilities and locations to remain competitive and attract customer traffic to our stores. Sunoco LP may not be able to compete successfully against current and future competitors, and competitive pressures faced by Sunoco LP could have a material adverse effect on its business, results of operations and cash available for distribution to unitholders.

Sunoco LP currently depends on a limited number of principal suppliers in each of its operating areas for a substantial portion of its merchandise inventory and its products and ingredients for its food service facilities. A disruption in supply or a change in either relationship could have a material adverse effect on its business.

Sunoco LP currently depends on a limited number of principal suppliers in each of its operating areas for a substantial portion of its merchandise inventory and its products and ingredients for its food service facilities. If any of Sunoco LP's principal suppliers elect not to renew their contracts, Sunoco LP may be unable to replace the volume of merchandise inventory and products and ingredients currently purchased from them on similar terms or at all in those operating areas. Further, a disruption in supply or a significant change in Sunoco LP's relationship with any of these suppliers could have a material adverse effect on Sunoco LP's business, financial condition and results of operations and cash available for distribution to unitholders.

Sunoco LP may be subject to adverse publicity resulting from concerns over food quality, product safety, health or other negative events or developments that could cause consumers to avoid its retail locations or independently operated commission agent or dealer locations.

Sunoco LP may be the subject of complaints or litigation arising from food-related illness or product safety which could have a negative impact on its business. Negative publicity, regardless of whether the allegations are valid, concerning food quality, food safety or other health concerns, food service facilities, employee relations or other matters related to its operations may materially adversely affect demand for its food and other products and could result in a decrease in customer traffic to its retail stores or independently operated commission agent or dealer locations.

It is critical to Sunoco LP’s reputation that they maintain a consistent level of high quality at their food service facilities and other franchise or fast food offerings. Health concerns, poor food quality or operating issues stemming from one store or a limited number of stores could materially and adversely affect the operating results of some or all of their stores and harm the company-owned brands, continuing favorable reputation, market value and name recognition.

USAC’s customers may choose to vertically integrate their operations by purchasing and operating their own compression fleet, increasing the number of compression units they currently own or using alternative technologies for enhancing crude oil production.

USAC’s customers that are significant producers, processors, gatherers and transporters of natural gas and crude oil may choose to vertically integrate their operations by purchasing and operating their own compression fleets in lieu of using USAC’s compression services. The historical availability of attractive financing terms from financial institutions and equipment manufacturers facilitates this possibility by making the purchase of individual compression units increasingly affordable to USAC's customers. In addition, there are many technologies available for the artificial enhancement of crude oil production, and USAC's customers may elect to use these alternative technologies instead of the gas lift compression services USAC provides. Such vertical integration, increases in vertical integration or use of alternative technologies could result in decreased demand for USAC's compression services, which may have a material adverse effect on its business, results of operations, financial condition and reduce its cash available for distribution.

A significant portion of USAC's services are provided to customers on a month-to-month basis, and USAC cannot be sure that such customers will continue to utilize its services.

USAC's contracts typically have an initial term of between six months and five years, depending on the application and location of the compression unit. After the expiration of the initial term, the contract continues on a month-to-month or longer basis until terminated by USAC or USAC's customers upon notice as provided for in the applicable contract. As of December 31, 2018, approximately 47% of USAC's compression services on a revenue basis were provided on a month-to-month basis to customers who continue to utilize its services following expiration of the primary term of their contracts. These customers can generally terminate their month-to-month compression services contracts on 30-days’ written notice. If a significant number of these customers were to terminate their month-to-month services, or attempt to renegotiate their month-to-month contracts at substantially lower rates, it could have a material adverse effect on USAC's business, results of operations, financial condition and cash available for distribution.

USAC’s Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of its common units.

USAC’s Preferred Units rank senior to all of its other classes or series of equity securities with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for its common units, or could make it more difficult for USAC to sell its common units in the future.

In addition, distributions on USAC’s Preferred Units accrue and are cumulative, at the rate of 9.75% per annum on the original issue price, which amounts to a quarterly distribution of $24.375 per Preferred Unit. If USAC does not pay the required distributions on its Preferred Units, USAC will be unable to pay distributions on its common units. Additionally, because distributions on USAC’s Preferred Units are cumulative, USAC will have to pay all unpaid accumulated distributions on the Preferred Units before USAC can pay any distributions on its common units. Also, because distributions on USAC’s common units are not cumulative, if USAC does not pay distributions on its common units with respect to any quarter, USAC’s common unitholders will not be entitled to receive distributions covering any prior periods if USAC later recommences paying distributions on its common units.

USAC’s Preferred Units are convertible into common units by the holders of USAC’s Preferred Units or by USAC in certain circumstances. USAC’s obligation to pay distributions on USAC’s Preferred Units, or on the common units issued following the conversion of USAC’s Preferred Units, could impact USAC’s liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions and other general Partnership purposes. USAC’s obligations to the holders of USAC’s Preferred Units could also limit its ability to obtain additional financing or increase its borrowing costs, which could have an adverse effect on its financial condition.

The use of derivative financial instruments could result in material financial losses by us.
From time to time, we and/or our subsidiaries 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 unitholders.

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Sunoco LP does not own all of the land on which its retail service stations are located, and Sunoco LP leases certain facilities and equipment, and Sunoco LP is subject to the possibility of increased costs to retain necessary land use which could disrupt its operations.

Sunoco LP does not own all of the land on which its retail service stations are located. Sunoco LP has rental agreements for approximately 38.1% of the company, commission agent or dealer operated retail service stations where Sunoco LP currently controls the real estate. Sunoco LP also has rental agreements for certain logistics facilities. As such, Sunoco LP is subject to the possibility of increased costs under rental agreements with landowners, primarily through rental increases and renewals of expired agreements. Sunoco LP is also subject to the risk that such agreements may not be renewed. Additionally, certain facilities and equipment (or parts thereof) used by Sunoco LP are leased from third parties for specific periods. Sunoco LP's inability to renew leases or otherwise maintain the right to utilize such facilities and equipment on acceptable terms, or the increased costs to maintain such rights, could have a material adverse effect on its financial condition, results of operations and cash flows.

We, Sunoco LP and USAC 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, 2018, our consolidated balance sheet reflected $4.89 billion of goodwill and $6.00 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 2018, the Partnership recognized goodwill impairments of $378 million related to our Northeast operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded. These changes in assumptions reflect delays in the construction of third-party takeaway capacity in the Northeast. During 2018, Sunoco LP recognized a $30 million impairment charge on its contractual rights.

During the fourth quarter of 2017, the Partnership 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 2017, Sunoco LP recognized goodwill an impairment of $102 million on its retail reporting unit.

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.

If we and our subsidiaries 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 make 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.

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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 2018, Trafigura US Inc. accounted for approximately 32% of our intrastate transportation and storage revenues. During 2018, Shell, Ascent Resources LLC and Antero Resources Corporation collectively accounted for 38% 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 2018 while Citrus

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has long-term agreements with its top two customers which accounted for 59% of its 2018 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. Effective January 2018, the 2017 Tax and Jobs Act (the "Tax Act") changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, in a set of related proposals, the FERC addressed treatment of federal income tax allowances in regulated entity rates. The FERC issued a Revised Policy Statement on Treatment of Income Taxes ("Revised Policy Statement") stating that it will no longer permit master limited partnerships to recover an income tax allowance in their cost of service rates. The FERC issued the Revised Policy Statement in response to a remand from the United States Court of Appeals for the District of Columbia Circuit in United Airlines v. FERC, in which the court determined that the FERC had not justified its conclusion that a pipeline organized as a master limited partnership would not "double recover" its taxes under the current policy by both including an income-tax allowance in its cost of service and earning a return on equity calculated using the discounted cash flow methodology. On July 18, 2018, the FERC issued an order denying requests for rehearing and clarification of its Revised Policy Statement because it is a non-binding policy and parties will have the opportunity to address the policy as applied in future cases. In the rehearing order, the FERC clarified that a pipeline organized as a master limited partnership will not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs.

Included in the March 15, 2018 proposals is a Notice of Proposed Rulemaking ("NOPR") proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to natural gas pipeline rates. On July 18, 2018, the FERC issued a Final Rule (Order No. 849) adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the Final Rule requires all FERC regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information and to make an election on how to treat its existing rates. The Final Rule suggests that this information will allow the FERC and

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other stakeholders to evaluate the impacts of the Tax Act and the Revised Policy Statement on each individual pipeline's rates. The Final Rule also requires that each FERC regulated natural gas pipeline select one of four options: file a limited Natural Gas Act ("NGA") Section 4 filing reducing its rates only as required related to the Tax Act and the Revised Policy Statement, commit to filing a general NGA Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. For the limited NGA Section 4 option, the FERC clarified that, notwithstanding the Revised Policy Statement, a pipeline organized as a master limited partnership does not need to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. Trunkline, ETC Tiger Pipeline, LLC and Panhandle filed their respective FERC Form No. 501-Gs on October 11, 2018. FEP, Lake Charles LNG and certain other operating subsidiaries filed their respective FERC Form No. 501-Gs on or about November 8, 2018. Rover, FGT, Transwestern and MEP filed their respective FERC Form No. 501-Gs on or about December 6, 2018. 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. For example, the FERC has recently initiated reviews of Panhandle's and Southwest Gas Storage Company's existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged are just and reasonable. These reviews will require the filing of a cost and revenue study prior to the FERC issuing a decision.

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 refined products pipeline operations.

Transportation provided on our common carrier interstate crude oil, NGL and refined 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-

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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 Energy Policy Act 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. In 2018, PHMSA announced its intention to divide the original proposed rulemaking into three parts and issue three separate final rulemakings in 2019. PHMSA indicated that the first of the

three final rulemakings could come as early as March 2019, although that timing is likely to be impacted by the federal government shutdown. 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. In November 2018, PHMSA issued a final rule increasing the maximum administrative fines for safety violations were increased to account for inflation, with maximum civil penalties set at $213,268 per day, with a maximum of $2,132,679 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, which are expected in 2019. 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. In 2018, PHMSA announced its intention to divide the original proposed rulemaking into three parts and issue three separate final rulemakings in 2019. PHMSA indicated that the first of the three final rulemakings could come as early as March 2019, although that timing is likely to be impacted by the federal government shutdown from December 2018 through January 2019. 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.” The EPA finalized its non-attainment designations for the remaining areas of the United States not addressed under the November 2017 final rule in April and July 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

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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.

Regulations under the Clean Water Act, OPA and state laws impose regulatory burdens on terminal operations. Spill prevention control and countermeasure requirements of federal and state laws require containment to mitigate or prevent contamination of waters in the event of a refined product overflow, rupture, or leak from above-ground pipelines and storage tanks. The Clean Water Act also requires us to maintain spill prevention control and countermeasure plans at our terminal facilities with above-ground storage tanks and pipelines. In addition, OPA requires that most fuel transport and storage companies maintain and update various oil spill prevention and oil spill contingency plans. Facilities that are adjacent to water require the engagement of Federally Certified Oil Spill Response Organizations ("OSRO"s) to be available to respond to a spill on water from above-ground storage tanks or pipelines.

Transportation and storage of refined products over and adjacent to water involves risk and potentially subjects us to strict, joint, and potentially unlimited liability for removal costs and other consequences of an oil spill where the spill is into navigable waters, along shorelines or in the exclusive economic zone of the United States. In the event of an oil spill into navigable waters, substantial liabilities could be imposed upon us. The Clean Water Act imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters, with the potential of substantial liability for the violation of permits or permitting requirements.

Terminal operations and associated facilities are subject to the Clean Air Act as well as comparable state and local statutes. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions, and operating permits may be required for sources that are already constructed. If regulations become more stringent, additional emission control technologies

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 GHGs 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 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. In September 2018, the EPA proposed amendments to Subpart OOOOa that would reduce the 2016 standards' fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other changes. Various industry and environmental groups have separately challenged both the original 2016 standards and the EPA's attempts to delay the implementation of the rule. 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 OTC 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.

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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.

We have preferred units that are listed on the NYSE. 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. 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.

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.

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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, 2018, approximately 12% 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 substantial majority of the components for our natural gas compression equipment are supplied by Caterpillar Inc., Cummins Inc. and Arrow Engine Company for engines, Air-X-Changers and Alfa Laval (US) for coolers, and Ariel Corporation, GE Oil & Gas Gemini products and Arrow Engine Company for compressor frames and cylinders. 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 four vendors, A G Equipment Company, Alegacy Equipment, LLC, Standard Equipment Corp. and Genis Holdings LLC, 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 any of these sources could have a negative impact on our results of operations and could damage our customer relationships. Some of these suppliers manufacture the components we purchase in a single facility, and any damage to that facility could lead to significant delays in delivery of completed compression units to us.

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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, our wholly-owned subsidiary, is in the process of developing a liquefaction project at the site of our existing regasification facility in Lake Charles, Louisiana. The project development agreement previously entered into in September 2013 with BG Group plc, a subsidiary of 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 us 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 FERC order (issued December 17, 2015) authorizing LCL to site, construct and operate the liquefaction project contains a condition requiring all phases of the liquefaction project to be completed and in-service within five years of the date of the order. The order also requires the modifications to our Trunkline pipeline facilities that connect to our Lake Charles facility be complete by December 17, 2019 and additionally requires execution of a transportation contract for natural gas supply to the liquefaction facility prior to the initiation of construction of the liquefaction facility. Although we intend to file an application with the FERC to seek an extension of these completion dates for the project, the FERC may not grant this extension.
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

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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.

Sunoco LP is subject to federal laws related to the Renewable Fuel Standard.

New laws, new interpretations of existing laws, increased governmental enforcement of existing laws or other developments could require us to make additional capital expenditures or incur additional liabilities. For example, certain independent refiners have initiated discussions with the EPA to change the way the Renewable Fuel Standard (“RFS”) is administered in an attempt to shift the burden of compliance from refiners and importers to blenders and distributors. Under the RFS, which requires an annually increasing amount of biofuels to be blended into the fuels used by U.S. drivers, refiners/importers are obligated to obtain renewable identification numbers (“RINS”) either by blending biofuel into gasoline or through purchase in the open market. If the obligation was shifted from the importer/refiner to the blender/distributor, the Partnership would potentially have to utilize the RINS it obtains through its blending activities to satisfy a new obligation and would be unable to sell RINS to other obligated parties, which may cause an impact on the fuel margins associated with Sunoco LP’s sale of gasoline.

The occurrence of any of the events described above could have a material adverse effect on Sunoco LP’s business, financial condition, results of operations and cash available for distribution to its unitholders.

Sunoco LP is subject to federal, state and local laws and regulations that govern the product quality specifications of refined petroleum products it purchases, stores, transports, and sells to its distribution customers.

Various federal, state, and local government agencies have the authority to prescribe specific product quality specifications for certain commodities, including commodities that Sunoco LP distributes. Changes in product quality specifications, such as reduced sulfur content in refined petroleum products, or other more stringent requirements for fuels, could reduce Sunoco LP’s ability to procure product, require it to incur additional handling costs and/or require the expenditure of capital. If Sunoco LP is unable to procure product or recover these costs through increased selling price, it may not be able to meet its financial obligations. Failure to comply with these regulations could result in substantial penalties for Sunoco LP.

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 Series A Preferred Units, Series B Preferred Units, Series C Preferred Units and Series D Preferred Units (collectively, “ETO Preferred 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

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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 holders of our ETO Preferred Units ("ETO Preferred Unitholders") would generally be taxed again as corporate distributions and instead of guaranteed payments for the use of capital, as described further below. Because a tax would then be imposed upon us as a corporation, our cash available for distribution to ETO Preferred 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 ETO Preferred Unitholders.

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 ETO Preferred 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 ETO Preferred 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 ETO Preferred 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.

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 us. 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 us.

If the IRS contests the federal income tax positions we take, the market for our ETO Preferred Units may be adversely affected and the costs of any such contest will reduce cash available for distributions to our ETO Preferred 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 ETO Preferred 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 ETO Preferred 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 ETO Preferred 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 ETO Preferred Unitholder and former ETO Preferred Unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders, including ETO Preferred Unitholders and former ETO Preferred 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 ETO Preferred Unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such ETO Preferred Unitholders did not own

ETO Preferred Units 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 ETO Preferred Unitholders might be substantially reduced.

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

ETO Preferred Unitholders, who will be treated as our partners, may receive allocations of taxable income different in amount than the cash we distribute. ETO Preferred 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. ETO Preferred 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-exempt entities and non-U.S. persons face unique tax issues from owning our ETO Preferred Units that may result in adverse tax consequences to them.

Investment in the ETO 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 ETO Preferred Unitholders 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 ETO Preferred Unitholders may be required to file United States federal income tax returns in order to seek a refund of such excess.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-United States ETO Preferred 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 ETO Preferred Unitholders should consult a tax advisor before investing in our ETO Preferred 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 ETO Preferred 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.

An ETO Preferred Unitholder whose ETO Preferred Units are the subject of a securities loan (e.g. a loan to a “short seller”) to cover a short sale of ETO Preferred Units may be considered as having disposed of those ETO Preferred Units. If so, the ETO Preferred Unitholder would no longer be treated for tax purposes as a partner with respect to those ETO Preferred 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, an ETO Preferred Unitholder whose ETO Preferred Units are the subject of a securities loan may be considered as having disposed of the loaned ETO Preferred Units. In that case, the ETO Preferred Unitholder may no longer be treated for tax purposes as a partner with respect to those ETO Preferred Units during the period of the loan and may recognize gain or loss from such disposition. ETO Preferred Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their ETO Preferred 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 ETO Preferred Units.

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ETO Preferred 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 ETO Preferred Units.

In addition to federal income taxes, the ETO Preferred 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. ETO Preferred 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, ETO Preferred Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each ETO Preferred Unitholder to file all federal, state and local tax returns.

Treatment of distributions on our ETO Preferred Units as guaranteed payments for the use of capital is uncertain and such distributions may not be eligible for the 20% deduction for qualified publicly traded partnership income.

The tax treatment of distributions on our ETO Preferred Units is uncertain. We will treat ETO Preferred Unitholders as partners for tax purposes and will treat distributions on the ETO Preferred Units as guaranteed payments for the use of capital that will generally be taxable to ETO Preferred Unitholders as ordinary income. ETO Preferred Unitholders 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, ETO Preferred Unitholders 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 ETO Preferred Unitholders. If the ETO 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 ETO Preferred Unitholders.

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 ETO Preferred Units may not be eligible for the 20% deduction for qualified publicly traded partnership income.

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

All ETO Preferred Unitholders are urged to consult a tax advisor with respect to the consequences of owning our ETO 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; Houston, San Antonio, and Austin, 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 Sunoco, Inc. (R&M) (now known as Sunoco (R&M), LLC) (collectively, “Sunoco”) are defendants in lawsuits alleging MTBE contamination of groundwater. The plaintiffs, state-level governmental entities, assert product liability, nuisance, trespass, negligence, violation of environmental laws, and/or deceptive business practices claims. 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, 2018, Sunoco is a defendant in six cases, including one case each initiated by the States of Maryland, Vermont and 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.

In late July 2018, the Court in the Vermont matter denied the State of Vermont’s motion to amend its complaint to add specific allegations regarding some of the sites the court previously dismissed. The State of Vermont and the defendants reached a settlement in principle to resolve the remaining statewide Vermont Case in September 2018. The parties are in the process of finalizing settlement documents.

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.

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, EPA 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.

In October 2016, the PHMSA issued a Notice of Probable Violation (“NOPVs”) and a Proposed Compliance Order (“PCO”) related to ETO’s 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. ETO does not expect there to be a material impact to its 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 ETO's 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. ETO does not expect there to be a material impact to its 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. PHMSA Southwest Region has issued its post-hearing recommendations to PHMSA headquarters. The recommendations included a provision for alteration of the number of instances of violation for one NOPV.

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All remaining NOPVs are unchanged. There was a minor reduction in the civil penalty expected due to a reduction in the number of instances of violation for one NOPV, and the Proposed Compliance Order was fully withdrawn. 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 ETO's Nederland to Kilgore pipeline in Texas. The case remains open with PHMSA and the proposed penalties are in excess of $100,000. ETO does not expect there to be a material impact to its 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, hydrostatic permit violations involving the alleged discharge of effluent with greater levels of pollutants than the permits allowed and allegedly not properly sampling or monitoring effluent for required parameters or reporting those alleged violations, and engaging in construction activities without an effective water quality certification. Although Rover has successfully completed clean-up mitigation for the alleged violations to Ohio EPA's satisfaction, the Ohio EPA has proposed penalties and restitution 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. Rover and other defendants filed several motions to dismiss and Ohio EPA filed a motion in opposition. The State's opposition to those motions was filed on October 12, 2018. Rover and other defendants filed their replies on November 2, 2018. The court has not yet ruled on the motion. The State requested oral argument on the motion, but no argument has been scheduled to date. 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 has implemented the suggestions in the assessment and additional voluntary protocols. The FERC has authorized Rover to resume HDD activities at all sites.

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 ETO 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, ETO 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. On August 1, 2017 the EHB lifted the order as to two drill locations. On August 3, 2017, the EHB lifted the order as to 14 additional locations. The EHB issued the order in response to a complaint filed by environmental groups against SPLP and the PADEP. The EHB Judge encouraged the parties to pursue a settlement with respect to the remaining HDD locations and facilitated a settlement meeting. On August 7, 2017 a final settlement was reached. A stipulated order has been submitted to the EHB Judge with respect to the settlement. The settlement agreement requires 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. SPLP continued throughout 2018 to complete HDDs on the Mariner East 2 project using the reevaluation process outlined in the EHB order. On July 31, 2018, the environmental groups voluntarily dismissed their action in the EHB after reaching a settlement with the PADEP that did not involve SPLP.

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 has fulfilled the requirements of those agreements and has been authorized by PADEP to resume drilling the locations.

On January 3, 2018, PADEP issued an Administrative Order to SPLP 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 2017, during the construction of the project. SPLP 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 SPLP took an appeal of the Administrative Order to the Pennsylvania Environmental Hearing Board on February 2, 2018. On February 8, 2018, SPLP entered into a Consent Order and Agreement with PADEP that (i) withdraws the Administrative Order; (ii) establishes requirements for compliance with permits on a going forward basis; (iii) resolves the non-compliance alleged in the Administrative Order; and (iv) conditions restart of work on an agreement by SPLP to pay a $12.6 million civil penalty to the Commonwealth of Pennsylvania. In the Consent Order and agreement, SPLP 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 SPLP had adequately addressed the issues raised in the Administrative Order and demonstrated an ability to comply with the permits. SPLP 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. We have paid the civil penalties of $121,000. The case was closed in October 2018.

Energy Transfer Company Field Services received NOV REG-0569-1701 on June 6, 2017 for emission events that occurred January 1, 2017 through April 16, 2017 at the Jal 3 gas plant. On September 11, 2017, the New Mexico Environmental Department sent ETO a settlement offer to resolve the NOV for a penalty of $596,278. Negotiations for this settlement offer are ongoing.

Energy Transfer Company Field Services received NOV REG-0569-1702 on December 8, 2017 for emission events that occurred April 17, 2017 through September 23, 2017 at the Jal 3 gas plant. On January 31, 2018, ETO received a settlement offer to resolve the NOV for a penalty of $602,138. Negotiations for this settlement offer are ongoing.

Energy Transfer Company Field Services received NOV REG-0569-1801 on February 13, 2018 for emission events that occurred September 25, 2017 through December 29, 2017 at the Jal 3 gas plant. On June, 11, 2018, the New Mexico Environmental Department sent ETO a settlement offer to resolve the NOV for a penalty of $268,213. Negotiations for this settlement offer are ongoing.

On June 29, 2018, Luminant Energy Company, LLC (“Luminant”) filed informal and formal complaints against Energy Transfer Fuel, LP (“ETF”), with the Railroad Commission of Texas (“TRRC”). Luminant’s complaints allege that absent an agreement between Luminant and ETF regarding the rate to be charged for bundled transportation and storage service, ETF must file a statement of intent with the TRRC to change the rate charged to Luminant for this service. ETF filed a response to Luminant’s informal complaint on July 16, 2018. ETF filed a response and motion to dismiss Luminant’s formal complaint on July 23, 2018. On August 16, 2018, a Commission Administrative Law Judge (“ALJ”) granted ETF’s motion to dismiss Luminant’s claims relating to unlawful abandonment and discrimination. The ALJ denied ETF’s motion to dismiss Luminant’s claims regarding the rate charged for service and the procedural process applicable to rate changes. Luminant appealed the decision. The appeal was denied by operation of law on October 1, 2018. A mediation of the informal complaint filed by Luminant was held on September 17, 2018 and no decision was reached. The parties executed new agreements for transportation and storage services effective December 1, 2018. Luminant has withdrawn its formal and informal complaints against ETF, (unopposed by ETF), as of January 2, 2019.

In June 2018, ETC Northeast Pipeline LLC (“ETC Northeast”) entered into a Consent Order and Agreement with the PADEP, pursuant to which ETC Northeast agreed to pay $150,242 to the PADEP to settle various statutory and common law claims relating to soil discharge into, and erosion of the stream bed of, Raccoon Creek in Center Township, Pennsylvania during construction of the Revolution Pipeline. ETC Northeast has paid the settlement amount and continues to monitor the construction site and work with the landowner to resolve any remaining issues related to the restoration of the construction site.

Energy Transfer Company Field Services received NOV REG-0569-1802 from the New Mexico Environmental Department on July 25, 2018 for emission events that occurred January 1, 2018 through April 30, 2018 at the Jal 3 gas plant. On September 25, 2018, ETO received a settlement offer to resolve the NOV for a penalty of $1,151,499. Negotiations for this settlement offer are ongoing.

On September 17, 2018, William D. Warner ("Plaintiff"), a purported Energy Transfer Partners, L.P. unitholder, filed a putative class action asserting violations of various provisions of the Securities Exchange Act of 1934 and various rules promulgated thereunder in connection with the Energy Transfer Merger against ETO, Kelcy L. Warren, Michael K. Grimm, Marshall S. McCrea,

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Matthew S. Ramsey, David K. Skidmore, and W. Brett Smith (“Defendants”). Plaintiff specifically alleged that the proxy statement related to the Energy Transfer Merger omitted and/or misrepresented material information. On December 17, 2018, Plaintiff voluntarily dismissed his lawsuit.

Energy Transfer Field Company Services received NOV REG-0569-1803 from the New Mexico Environmental Department on November 8, 2018 for emission events that occurred May 1, 2018 through August 31, 2018 at the Jal 3 gas plant. On December 28, 2018, ETO received a settlement offer to resolve the NOV for a penalty of $1,405,652. Negotiations for this settlement offer are ongoing.

On September 10, 2018, a pipeline release and fire occurred on the Revolution Pipeline in the vicinity of Ivy Lane located in Center Township, Beaver County, Pennsylvania. There were no injuries but there were evacuations of local residents as a precautionary measure. The Pennsylvania Department of Environmental Protection (“PADEP”) and the Pennsylvania Public Utility Commission (“PUC”) are investigating the incident. On October 29, 2018, PADEP issued a Compliance Order requiring our subsidiary, ETC Northeast, to cease all earth disturbance activities at the site (except as necessary to repair and maintain existing Best Management Practices (“BMPs”) and temporarily stabilize disturbed areas), implement and/or maintain the Erosion and Sediment BMPs at the site, stake the limit of disturbance, identify and report all areas of non-compliance, and submit an updated Erosion and Sediment Control Plan, a Temporary Stabilization Plan, and an updated Post Construction Stormwater Management Plan. The scope of the Compliance Order has been expanded to include the disclosure to PADEP of alleged violations of environmental permits with respect to various construction and post-construction activities and restoration obligations along the 42-mile route of the Revolution line. ETC Northeast filed an appeal of the Compliance Order with the Pennsylvania Environmental Hearing Board.

On February 8, 2019, PADEP filed a Petition to Enforce the Compliance Order with Pennsylvania’s Commonwealth Court. The Court issued an Order on February 14, 2019 requiring the submission of an answer to the Petition on or before March 12, 2019, and scheduling a hearing on the Petition for March 26, 2019. PADEP has also and issued a Permit Hold on any requests for approvals/permits or permit amendments made by us or any of our subsidiaries for any projects in Pennsylvania pursuant to the state’s water laws. We continue to work through these issues with PADEP.

In January 2019, we received notice from the DOJ on behalf of the EPA that an enforcement action was being pursued under the Clean Water Act for an estimated 450 barrel crude oil release from the pipeline operated by SPLP and owned by Mid-Valley. The release purportedly occurred in October 2014 on a nature preserve located in Hamilton County, Ohio, near Cincinnati, Ohio. After discovery and notification of the release, SPLP conducted substantial emergency response and remedial efforts in three phases and that work is substantially complete. DOJ, on behalf of United States Department of Interior Fish and Wildlife, and the Ohio Attorney General, on behalf of Ohio EPA, along with technical representatives from those agencies have also been discussing natural resource damage assessment claims. 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.

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 10 to our consolidated financial statements included in “Item 8. Financial Statements and Supplementary Data.”

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

Description of Units

ETO Preferred Units

In November 2017, ETO 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. In April 2018, ETO issued 18 million of its 7.375% Series C Preferred Units at a price of $25 per unit. In July 2018, ETO issued 17.8 million of its 7.625% Series D Preferred Units at a price of $25 per unit. Subsequent to the Energy Transfer Merger, all of ETO's Series A, Series B, Series C and Series D Preferred Units remain outstanding.

ETO Series A Preferred Units

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 ETO'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.

ETO Series B Preferred Units

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 ETO'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.

ETO Series C Preferred Units

Distributions on the Series C Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2023, at a rate of 7.375% per annum of the stated liquidation preference of $25. On and after May 15, 2023, distributions on the Series C Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.530% per annum. The Series C Preferred Units are redeemable at ETO's option on or after May 15, 2023 at a redemption price of $25 per Series C Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series D Preferred Units

Distributions on the Series D Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, August 15, 2023, at a rate of 7.625% per annum of the stated liquidation preference of $25. On and after August 15, 2023, distributions on the Series D Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.738% per annum. The Series D Preferred Units are redeemable at ETO's option on or after August 15, 2023 at a redemption price of $25 per Series D 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 within 45 days following the end of each fiscal quarter. Our general partner does not receive a distribution.

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 (including reserves for future capital expenditures and for our future capital needs);

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- comply with applicable law and/or debt instrument or other agreement; or
- provide funds for distributions to the Series A, Series B, Series C and Series D Preferred Unitholders.
- 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.

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 Energy Transfer Merger resulted in the retrospective adjustment to consolidate Sunoco LP and Lake Charles LNG for all periods presented and USAC beginning April 2, 2018.

As discussed in Note 1 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" the merger of legacy ETO (the entity named Energy Transfer Partners, L.P. prior to the merger) and legacy Sunoco Logistics in April 2017 resulted in legacy ETO being treated as the surviving entity from an accounting perspective. Accordingly, the selected financial data below reflects the consolidated financial information of legacy ETO.

	Years Ended December 31,				
	2018	2017	2016	2015	2014
Statement of Operations Data:					
Total revenues	$54,087	$40,523	$31,792	$36,096	$54,435
Operating income	5,402	2,765	1,975	2,341	2,461
Income from continuing operations	4,039	2,952	911	1,371	1,289
Balance Sheet Data (at period end):					
Assets held for sale	—	3,313	3,588	3,681	3,372
Total assets [1]	88,442	86,484	78,984	71,117	63,928
Liabilities associated with assets held for sale	—	75	48	42	47
Long-term debt, less current maturities	37,853	36,971	36,251	30,505	24,831
Total equity	36,621	36,967	28,938	29,968	26,732
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis) [2]	510	479	474	550	449
Growth (accrual basis) [2]	5,120	5,601	5,775	8,046	5,218
Cash paid for acquisitions	429	583	1,398	964	2,367

(1) Includes assets held for sale

(2) Maintenance and growth capital expenditures include Sunoco LP's capital expenditures related to discontinued operations.

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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 "ETO" shall mean Energy Transfer Operating, 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;
- interstate natural gas transportation and storage; and
- crude oil, NGL and refined products transportation, terminalling services and acquisition and marketing activities, as well as NGL storage and fractionation services.

In addition, we own investments in other businesses, including Sunoco LP and USAC, both of which are publicly traded master limited partnerships.

Recent Developments

ETO 2019 Senior Notes Offering and Redemption

In January 2019, ETO issued $750 million aggregate principal amount of 4.50% senior notes due 2024, $1.50 billion aggregate principal amount of 5.25% senior notes due 2029 and $1.75 billion aggregate principal amount of 6.25% senior notes due 2049. The $3.96 billion net proceeds from the offering were used to repay in full ET's outstanding senior secured term loan, to redeem outstanding senior notes, to repay a portion of the borrowings under the Partnership's revolving credit facility and for general partnership purposes.

Energy Transfer Merger

In October 2018, we completed the merger of ETO with a wholly-owned subsidiary of ET in a unit-for-unit exchange (the "Energy Transfer Merger"). In connection with the transaction, ETO unitholders (other than ET and its subsidiaries) received 1.28 common units of ET for each common unit of ETO they owned.

Immediately prior to the closing of the Energy Transfer Merger, the following also occurred:

- the IDRs in ETO were converted into 1,168,205,710 ETO common units; and
- the general partner interest in ETO was converted to a non-economic general partner interest and ETO issued 18,448,341 ETO common units to ETP GP.

Immediately prior to the closing of the Energy Transfer Merger discussed in "Item 8. Financial Statements and Supplementary Data," ET contributed the following to ETO:

- 2,263,158 common units representing limited partner interests in Sunoco LP to ETO in exchange for 2,874,275 ETO common units;
- 100 percent of the limited liability company interests in Sunoco GP LLC, the sole general partner of Sunoco LP, and all of the IDRs in Sunoco LP, to ETO in exchange for 42,812,389 ETO common units;
- 12,466,912 common units representing limited partner interests in USAC and 100 percent of the limited liability company interests in USA Compression GP, LLC, the general partner of USAC, to ETO in exchange for 16,134,903 ETO common units; and
- a 100 percent limited liability company interest in Lake Charles LNG and a 60 percent limited liability company interest in each of Energy Transfer LNG Export, LLC, ET Crude Oil Terminals, LLC and ETC Illinois LLC (collectively, "Lake Charles LNG and Other") to ETO in exchange for 37,557,815 ETO common units.

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Permian Gulf Coast Pipeline Joint Venture

In September 2018, ETO, Magellan Midstream Partners, L.P., MPLX LP and Delek US Holdings, Inc. announced that they have received sufficient commitments to proceed with plans to construct a new 30-inch diameter common carrier pipeline, the Permian Gulf Coast ("PGC") pipeline, to transport crude oil from the Permian Basin to the Texas Gulf Coast region. The 600-mile PGC pipeline system is expected to be operational in mid-2020 with multiple Texas origins. The pipeline system will have the strategic capability to transport crude oil to ETO's Nederland, Texas terminal for ultimate delivery through its distribution system. The project is subject to receipt of customary regulatory and Board approvals of the respective entities, and the transaction structure for this project has not been finalized.

Series D Preferred Units Issuance

In July 2018, ETO issued 17.8 million of its 7.625% Series D Preferred Units (liquidation preference of $25 per unit) resulting in total gross proceeds of $445 million. The proceeds were used to repay amounts outstanding under ETO's revolving credit facility and for general partnership purposes.

ETO 2018 Senior Notes Offering and Redemption

In June 2018, ETO issued $500 million aggregate principal amount of 4.20% senior notes due 2023, $1.00 billion aggregate principal amount of 4.95% senior notes due 2028, $500 million aggregate principal amount of 5.80% senior notes due 2038 and $1.00 billion aggregate principal amount of 6.00% senior notes due 2048. The $2.96 billion net proceeds from the offering were used to redeem outstanding senior notes, to repay borrowings outstanding under ETO's revolving credit facility and for general partnership purposes.

Old Ocean Joint Venture Formation

In May 2018, ETO and Enterprise Products Partners L.P. announced the formation of a joint venture to resume service on the Old Ocean natural gas pipeline. The 24-inch diameter pipeline resumed service in May 2018 and ETO is the operator. Additionally, both parties completed the expansion of their jointly owned North Texas 36-inch pipeline that provides more capacity for deliveries from West Texas into the Old Ocean pipeline.

Acquisition of HPC

ETO previously owned a 49.99% interest in HPC, which owns RIGS. In April 2018, ETO acquired the remaining 50.01% interest in HPC. Prior to April 2018, HPC was reflected as an unconsolidated affiliate in ETO's financial statements; beginning in April 2018, RIGS is reflected as a wholly-owned subsidiary in ETO's financial statements.

Series C Preferred Units Issuance

In April 2018, ETO issued 18 million of its 7.375% Series C Preferred Units (liquidation preference of $25 per unit) resulting in total gross proceeds of $450 million. The proceeds were used to repay amounts outstanding under ETO's revolving credit facility and for general partnership purposes.

CDM Contribution

On April 2, 2018, ET acquired a controlling interest in USAC, a publicly traded partnership that provides compression services in the United States. Specifically the Partnership acquired (i) all of the outstanding limited liability company interests in USA Compression GP, LLC ("USAC GP"), the general partner of USAC, and (ii) 12,466,912 USAC common units representing limited partner interests in USAC for cash consideration equal to $250 million (the "USAC Transaction"). Concurrently, USAC cancelled its incentive distribution rights and converted its economic general partner interest into a non-economic general partner interest in exchange for the issuance of 8,000,000 USAC common units to USAC GP.

Concurrent with these transactions, ETO contributed to USAC all of the issued and outstanding membership interests of CDM for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 USAC common units, (ii) 6,397,965 units of a new class of units representing limited partner interests in USAC ("USAC Class B Units") and (iii) $1.23 billion in cash, including customary closing adjustments (the "CDM Contribution"). The USAC Class B Units have substantially all of the rights and obligations of a USAC common unit, except the USAC Class B Units will not participate in distributions for the first four quarters following the closing date of April 2, 2018. Each USAC Class B Unit will automatically convert into one USAC common unit on the first business day following the record date attributable to the quarter ending June 30, 2019.

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New Ethane Export Facility Joint Venture

In March 2018, ETO and Satellite Petrochemical USA Corp. (“Satellite”) entered into definitive agreements to form a joint venture, Orbit Gulf Coast NGL Exports, LLC (“Orbit”), with the purpose of constructing a new export terminal on the United States Gulf Coast to provide ethane to Satellite for consumption at their ethane cracking facilities in China. At the terminal, Orbit will construct an 800 MBbls refrigerated ethane storage tank, a 175 MBbls/d ethane refrigeration facility and a 20-inch ethane pipeline originating at ETO’s Mont Belvieu fractionators that will make deliveries to the terminal as well as domestic markets in the region. ETO will be the operator of the Orbit assets, provide storage and marketing services for Satellite and provide Satellite with approximately 150 MBbls/d of ethane under a long-term, demand-based agreement. Additionally, ETO will construct and wholly own the infrastructure that is required to both supply ethane to the pipeline and to load the ethane on to very large ethane carriers destined for Satellite’s newly constructed ethane crackers in China’s Jiangsu Province. Subject to Chinese Governmental approval, it is anticipated that the Orbit export terminal will be ready for commercial service in the fourth quarter of 2020.

Sunoco LP Retail Store and Real Estate Sales

On April 1, 2018, Sunoco LP completed the conversion of 207 retail sites located in certain West Texas, Oklahoma and New Mexico markets to a single commission agent. Under the commission agent model, Sunoco LP owns, prices and sells fuel at the sites, paying the commission agent a fixed cents-per-gallon commission and receives rental income from the commission agent. The commission agent conducts all operations related to the retail stores and related restaurant locations.

On January 23, 2018, Sunoco LP closed on an asset purchase agreement with 7-Eleven and SEI Fuel Services, Inc., a Texas corporation and wholly-owned subsidiary of 7-Eleven. Under the agreement, Sunoco LP sold a portfolio of approximately 1,030 company-operated retail fuel outlets in 19 geographic regions, together with ancillary businesses and related assets, including the proprietary Laredo Taco Company brand, for an aggregate purchase price of $3.2 billion.

On January 18, 2017, with the assistance of a third-party brokerage firm, Sunoco LP launched a portfolio optimization plan to market and sell 97 real estate assets. Real estate assets included in this process are company-owned locations, undeveloped greenfield sites and other excess real estate. Properties are located in Florida, Louisiana, Massachusetts, Michigan, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas and Virginia. The properties are being sold through a sealed-bid. Of the 97 properties, 51 have been sold, one is under contract to be sold, and four continue to be marketed by the third-party brokerage firm. Additionally, 32 were sold to 7-Eleven and nine are part of the approximately 207 retail sites located in certain West Texas, Oklahoma, and New Mexico markets which are operated by a commission agent.

Sunoco LP Series A Preferred Units

On January 25, 2018, Sunoco LP redeemed all outstanding Sunoco LP Series A Preferred Units held by ET for an aggregate redemption amount of approximately $313 million. The redemption amount includes the original consideration of $300 million and a 1% call premium plus accrued and unpaid quarterly distributions.

Sunoco LP Senior Notes Offering

On January 23, 2018, Sunoco LP completed a private offering of $2.2 billion of senior notes, comprised of $1.0 billion in aggregate principal amount of 4.875% senior notes due 2023, $800 million in aggregate principal amount of 5.500% senior notes due 2026 and $400 million in aggregate principal amount of 5.875% senior notes due 2028. Sunoco LP used the proceeds from the private offering, along with proceeds from its retail divestment, to: i) redeem in full its existing senior notes, comprised of $800 million in aggregate principal amount of 6.250% senior notes due 2021, $600 million in aggregate principal amount of 5.500% senior notes due 2020 and $800 million in aggregate principal amount of 6.375% senior notes due 2023; ii) repay in full and terminate its term loan; iii) pay all closing costs in connection with its retail divestment; iv) redeem the outstanding Sunoco LP Series A Preferred Units; and v) repurchase 17,286,859 Sunoco LP common units owned by ETO.

On December 3, 2018, Sunoco LP completed an exchange of the notes for registered notes with substantially identical terms.

Sunoco LP Common Unit 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 ETO for aggregate cash consideration of approximately $540 million. ETO used the proceeds from the sale of the Sunoco LP common units to repay amounts outstanding under its revolving credit facility.

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Regulatory Update

Interstate Natural Gas Transportation Regulation

Effective January 2018, the 2017 Tax and Jobs Act (the “Tax Act”) changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, in a set of related proposals, the FERC addressed treatment of federal income tax allowances in regulated entity rates. The FERC issued a Revised Policy Statement on Treatment of Income Taxes (“Revised Policy Statement”) stating that it will no longer permit master limited partnerships to recover an income tax allowance in their cost of service rates. The FERC issued the Revised Policy Statement in response to a remand from the United States Court of Appeals for the District of Columbia Circuit in United Airlines v. FERC, in which the court determined that the FERC had not justified its conclusion that a pipeline organized as a master limited partnership would not “double recover” its taxes under the current policy by both including an income-tax allowance in its cost of service and earning a return on equity calculated using the discounted cash flow methodology. On July 18, 2018, the FERC issued an order denying requests for rehearing and clarification of its Revised Policy Statement because it is non-binding policy and parties will have the opportunity to address the policy as applied in future cases. In the rehearing order, the FERC clarified that a pipeline organized as a master limited partnership will not be not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors’ income tax costs. In light of the rehearing order, the impacts of the FERC’s policy on the treatment of income taxes may have on the rates ETO can charge for the FERC regulated transportation services are unknown at this time.

The FERC also issued a Notice of Inquiry (“2017 Tax Law NOI”) requesting comments on the effect of the Tax Act on FERC jurisdictional rates. The 2017 Tax Law NOI states that of particular interest to the FERC is whether, and if so how, the FERC should address changes relating to accumulated deferred income taxes and bonus depreciation. Comments in response to the 2017 Tax Law NOI were due on or before May 21, 2018. It is unknown at this time what actions that the FERC will take, if any, following receipt of responses to the 2017 Tax Law NOI and any potential impacts from final rules or policy statements issued following the 2017 Tax Law NOI on the rates ETO can charge for FERC regulated transportation services.

Included in the March 15, 2018 proposals is a Notice of Proposed Rulemaking (“NOPR”) proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to natural gas pipeline rates. On July 18, 2018, the FERC issued a Final Rule adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the Final Rule requires all FERC regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information and to make an election on how to treat its existing rates. The Final Rule suggests that this information will allow the FERC and other stakeholders to evaluate the impacts of the Tax Act and the Revised Policy Statement on each individual pipeline’s rates. The Final Rule also requires that each FERC regulated natural gas pipeline select one of four options: file a limited Natural Gas Act (“NGA”) Section 4 filing reducing its rates only as required related to the Tax Act and the Revised Policy Statement, commit to filing a general NGA Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. For the limited NGA Section 4 option, the FERC clarified that, notwithstanding the Revised Policy Statement, a pipeline organized as a master limited partnership does not need to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. Trunkline, ETC Tiger Pipeline, LLC and Panhandle filed their respective FERC Form No. 501-Gs on October 11, 2018. FEP, Lake Charles LNG and certain other operating subsidiaries filed their respective FERC Form No. 501-Gs on or about November 8, 2018, and Rover, FGT, Transwestern and MEP filed their respective FERC Form No. 501-Gs on or about December 6, 2018. By order issued January 16, 2019, the FERC initiated a review of Panhandle’s existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Panhandle are just and reasonable and set the matter for hearing. Panhandle must file a cost and revenue study on or before April 1, 2019. An initial decision is expected to be issued in the first quarter of 2020. By order issued February 19, 2019, the FERC initiated a review of Southwest Gas Storage Company’s existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Southwest Gas Storage Company are just and reasonable and set the matter for hearing. Southwest Gas Storage Company must file a cost and revenue study on or before May 6, 2019. The FERC is directing that an initial decision be issued within 47 weeks of the date the cost and revenue study is due.

Even without action on the 2017 Tax Law NOI or as contemplated in the Final Rule, the FERC or our shippers may challenge the cost of service rates we charge. The FERC's establishment of a just and reasonable rate is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect the FERC's determination of just and reasonable cost of service rates. Although changes in these two tax related components may decrease, other components in the cost of service rate calculation may increase and result in a newly calculated cost of service rate that is the same as or greater than the prior cost of service rate. Moreover, we receive revenues from our pipelines based on a variety of rate structures, including cost of service rates, negotiated rates, discounted rates and market-based rates. Many of our interstate pipelines, such as ETC Tiger Pipeline, LLC, 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 Panhandle, have a mix of tariff rate, discount rate, and negotiated rate agreements. We do not expect market-based rates, negotiated rates or discounted rates that are not tied to the cost of service rates to be affected by the Revised Policy Statement or any final regulations that may result from the March 15, 2018 proposals. The revenues we receive from natural gas transportation services we provide pursuant to cost of service based rates may decrease in the future as a result of the ultimate outcome of the NOI, the Final Rule, and the Revised Policy Statement, combined with the reduced corporate federal income tax rate established in the Tax Act. The extent of any revenue reduction related to our cost of service rates, if any, will depend on a detailed review of all of ETO’s cost of service components and the outcomes of any challenges to our rates by the FERC or our shippers.

The FERC issued a Notice of Inquiry on April 19, 2018 (“Pipeline Certification NOI”), thereby initiating a review of 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 as a result of the Pipeline Certification NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. Comments in response to the Pipeline Certification NOI were due on or before July 25, 2018. We do not expect that any change in this policy would affect us in a materially different manner than any other natural gas pipeline company operating in the United States.

Interstate Liquids Transportation Regulation

The FERC utilizes 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, or PPI. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. The FERC’s indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus 1.23 percent. Many existing pipelines utilize the FERC liquids index to change transportation rates annually every July 1. With respect to liquids and refined products pipelines subject to FERC jurisdiction, the Revised Policy Statement requires the pipeline to reflect the impacts to its cost of service from the Revised Policy Statement and the Tax Act on Page 700 of FERC Form No. 6. This information will be used by the FERC in its next five year review of the liquids pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Act in the determination of indexed rates prospectively, effective July 1, 2021. The FERC’s establishment of a just and reasonable rate, including the determination of the appropriate liquids pipeline index, is based on many components, and tax related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect the FERC’s determination of the appropriate pipeline index. Accordingly, depending on the FERC’s application of its indexing rate methodology for the next five year term of index rates, the Revised Policy Statement and tax effects related to the Tax Act may impact our revenues associated with any transportation services we may provide pursuant to cost of service based rates in the future, including indexed rates.

General

Our primary objective is to increase the level of our distributable cash flow 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, 2018 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 may 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

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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.

- Investment in Sunoco LP – Sunoco LP is a distributor of motor fuels and other petroleum products which Sunoco LP supplies to third-party dealers and distributors, to independent operators of commission agent locations, other commercial consumers of motor fuel and to its retail locations. Also included in the segment are transmix processing plants and refined products terminals. Transmix is the mixture of various refined products (primarily gasoline and diesel) created in the supply chain (primarily in pipelines and terminals) when various products interface with each other. Transmix processing plants separate this mixture and return it to salable products of gasoline and diesel.
- Investment in USAC – USAC provides compression services throughout the United States, including the Utica, Marcellus, Permian Basin, Delaware Basin, Eagle Ford, Mississippi Lime, Granite Wash, Woodford, Barnett, Haynesville, Niobrara and

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Fayetteville shales. USAC provides compression services to its customers primarily in connection with infrastructure applications, including both allowing for the processing and transportation of natural gas through the domestic pipeline system and enhancing crude oil production through artificial lift processes. As such, USAC's compression services play a critical role in the production, processing and transportation of both natural gas and crude oil.

Trends and Outlook

We anticipate significant earnings growth in 2019 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, natural gas prices have remained comparatively low during most of the last twelve months as associated gas from shale oil resources has provided additional supply to the market, while United States consumption has been relatively flat. This supports natural gas export projects to Mexico as well as LNG exports. Consequently, the Gulf Coast will likely be the fastest-growing demand market for United States natural gas.

Unlike natural gas, crude oil prices are influenced more by international markets than by domestic resources and technological advances. Prices have rebounded significantly from 2016 lows, signaling United States crude and NGL production should continue to grow rapidly, particularly in the Permian Basin and Bakken Shale, while domestic consumption falls. Energy exports from the United States are continuing to grow as a result, providing strong spreads from North Dakota and West Texas to the Gulf Coast.

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 Energy Transfer Merger in October 2018 resulted in the retrospective adjustment of the Partnership's consolidated financial statements to reflect consolidation beginning January 1, 2016 of Sunoco LP and Lake Charles LNG and April 2, 2018 for USAC.

As discussed in Note 1 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data," the merger of legacy ETO (the entity named Energy Transfer Partners, L.P. prior to the merger) and legacy Sunoco Logistics in April 2017 resulted in legacy ETO being treated as the surviving entity from an accounting perspective. Accordingly, the financial data below reflects the consolidated financial information of legacy ETO.

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

Consolidated Results

	Years Ended December 31,		
	2018	2017	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 927	$ 626	$ 301
Interstate transportation and storage	1,680	1,274	406
Midstream	1,627	1,481	146
NGL and refined products transportation and services	1,979	1,641	338
Crude oil transportation and services	2,330	1,379	951
Investment in Sunoco LP	638	732	(94)
Investment in USAC	289	—	289
All other	76	219	(143)
Total Segment Adjusted EBITDA	9,546	7,352	2,194
Depreciation, depletion and amortization	(2,843)	(2,541)	(302)
Interest expense, net	(1,709)	(1,575)	(134)
Impairment losses	(431)	(1,039)	608
Gains (losses) on interest rate derivatives	47	(37)	84
Non-cash compensation expense	(105)	(99)	(6)
Unrealized gains (losses) on commodity risk management activities	(11)	59	(70)
Inventory valuation adjustments	(85)	24	(109)
Losses on extinguishments of debt	(109)	(42)	(67)
Adjusted EBITDA related to unconsolidated affiliates	(655)	(716)	61
Equity in earnings of unconsolidated affiliates	344	144	200
Impairment of investments in unconsolidated affiliates	—	(313)	313
Adjusted EBITDA related to discontinued operations	25	(223)	248
Other, net	30	154	(124)
Income from continuing operations before income tax (expense) benefit	4,044	1,148	2,896
Income tax (expense) benefit from continuing operations	(5)	1,804	(1,809)
Income from continuing operations	4,039	2,952	1,087
Loss from discontinued operations, net of income taxes	(265)	(177)	(88)
Net income	$ 3,774	$ 2,775	$ 999

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.

Interest Expense, Net. Interest expense increased during the year ended compared December 31, 2018 to December 31, 2017 primarily due to the following:

- an increase of $121 million recognized by the Partnership primarily related to an increase in long-term debt, including additional senior note issuances and borrowings under our revolving credit facilities; and
- an increase of $78 million due to the acquisition of USAC on April 2, 2018; offset by
- a decrease of $65 million recognized by Sunoco LP primarily due to the repayment in full of its term loan and lower interest rates on its senior notes as a result of Sunoco LP's January 23, 2018 issuance of senior notes which paid off in full Sunoco LP's previously outstanding senior notes which had higher interest rates.

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Impairment Losses. During the year ended December 31, 2018, the Partnership recognized goodwill impairments of $378 million and asset impairments of $4 million related to our midstream operations and asset impairments of $9 million related to our crude operations idle leased assets. Sunoco LP recognized a $30 million indefinite-lived intangible impairment related to its contractual rights. USAC recognized a $9 million fixed asset impairment related to certain idle compressor assets.

During the year ended December 31, 2017, the Partnership recorded goodwill impairments of $223 million related to the compression business, $229 million related to Panhandle, $262 million related to the interstate transportation and storage segment and $79 million related to the NGL and refined products transportation and services segment. Sunoco LP recognized goodwill impairments of $387 million in 2017, of which $102 million was allocated to continuing operations. In addition, during the year ended December 31, 2017, the Partnership recorded an impairment to the property, plant and equipment of Sea Robin of $127 million. Additional discussion on these impairments is included in “Estimates and Critical Accounting Policies” below.

Gains (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. Gains (losses) on interest rate derivatives during the years ended December 31, 2018 and 2017 resulted from an increase in forward interest rates in 2018 and a decrease in forward interest rates in 2017, which caused our forward-starting swaps to change in value.

Unrealized Gains (Losses) on Commodity Risk Management Activities. See additional information on unrealized gain 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 Sunoco LP due to changes in fuel prices between periods.

Losses on Extinguishments of Debt. Amounts were related to Sunoco LP’s senior note and term loan redemption in January 2018.

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. Additional discussion on these impairments is included in “Estimates and Critical Accounting Policies” below.

Adjusted EBITDA Related to Discontinued Operations. Amounts were related to the operations of Sunoco LP’s retail business that were disposed of in January 2018.

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

Income Tax (Expense) 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 $1.78 billion in December 2017. For the year ended December 31, 2018, the Partnership recorded an income tax expense due to pre-tax income at its corporate subsidiaries, partially offset by a state statutory rate reduction.

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Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31,		
	2018	2017	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 141	$ 144	$ (3)
FEP	55	53	2
MEP	31	38	(7)
HPC [1][2]	3	(168)	171
Other	114	77	37
Total equity in earnings of unconsolidated affiliates	$ 344	$ 144	$ 200
Adjusted EBITDA related to unconsolidated affiliates[3]:			
Citrus	$ 337	$ 336	$ 1
FEP	74	74	—
MEP	81	88	(7)
HPC [2]	9	46	(37)
Other	154	172	(18)
Total Adjusted EBITDA related to unconsolidated affiliates	$ 655	$ 716	$ (61)
Distributions received from unconsolidated affiliates:			
Citrus	$ 171	$ 156	$ 15
FEP	68	47	21
MEP	48	114	(66)
HPC [2]	—	35	(35)
Other	111	80	31
Total distributions received from unconsolidated affiliates	$ 398	$ 432	$ (34)

(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) The partnership previously owned a 49.99% interest in HPC, which owns RIGS. In April 2018, we acquired the remaining 50.01% interest in HPC. Prior to April 2018, HPC was reflected as an unconsolidated affiliate in our financial statements; beginning in April 2018, RIGS is reflected as a wholly-owned subsidiary in our financial statements.

(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.

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- 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,	
	2018	2017
Segment Margin:		
Intrastate transportation and storage	$1,072	$756
Interstate transportation and storage	1,682	1,131
Midstream	2,377	2,182
NGL and refined products transportation and services	2,661	2,140
Crude oil transportation and services	2,893	1,877
Investment in Sunoco LP	1,122	1,108
Investment in USAC	441	—
All other	222	392
Intersegment eliminations	(41)	(29)
Total segment margin	12,429	9,557
Less:		
Operating expenses	3,089	2,644
Depreciation, depletion and amortization	2,843	2,541
Selling, general and administrative	664	568
Impairment losses	431	1,039
Operating income	$5,402	$2,765

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Intrastate Transportation and Storage

	Years Ended December 31,		
	2018	2017	Change
Natural gas transported (BBtu/d)	10,873	8,760	2,113
Revenues	$ 3,737	$ 3,083	$ 654
Cost of products sold	2,665	2,327	338
Segment margin	1,072	756	316
Unrealized (gains) losses on commodity risk management activities	38	(5)	43
Operating expenses, excluding non-cash compensation expense	(189)	(168)	(21)
Selling, general and administrative expenses, excluding non-cash compensation expense	(27)	(22)	(5)
Adjusted EBITDA related to unconsolidated affiliates	32	64	(32)
Other	1	1	—
Segment Adjusted EBITDA	$ 927	$ 626	$ 301

Volumes. For the year ended December 31, 2018 compared to the prior year, transported volumes increased primarily due to favorable market pricing spreads, as well as the impact of reflecting RIGS assets as a consolidated subsidiary beginning in April 2018.

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

	Years Ended December 31,		
	2018	2017	Change
Transportation fees	$ 525	$ 448	$ 77
Natural gas sales and other (excluding unrealized gains and losses)	510	196	314
Retained fuel revenues (excluding unrealized gains and losses)	59	58	1
Storage margin, including fees (excluding unrealized gains and losses)	16	49	(33)
Unrealized gains (losses) on commodity risk management activities	(38)	5	(43)
Total segment margin	$ 1,072	$ 756	$ 316

Segment Adjusted EBITDA. For the year ended December 31, 2018 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 $314 million in realized natural gas sales and other due to higher realized gains from pipeline optimization activity;
- a net increase of $14 million due to the consolidation of RIGS beginning in April 2018, resulting in increases in transportation fees, operating expenses, and selling, general and administrative expenses of $73 million, $16 million and $6 million, respectively, and a decrease of $37 million in Adjusted EBITDA related to unconsolidated affiliates; and
- an increase of $4 million in transportation fees, excluding the impact of consolidating RIGS as discussed above, primarily due to new contracts and the impact of the Red Bluff Express pipeline coming online in May 2018; partially offset by
- a decrease of $33 million in realized storage margin primarily due to an adjustment to the Bammel storage inventory, lower storage fees and lower realized derivative gains.

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Interstate Transportation and Storage

	Years Ended December 31,		
	2018	2017	Change
Natural gas transported (BBtu/d)	9,542	6,058	3,484
Natural gas sold (BBtu/d)	17	18	(1)
Revenues	$ 1,682	$ 1,131	$ 551
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(431)	(315)	(116)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(63)	(41)	(22)
Adjusted EBITDA related to unconsolidated affiliates	492	498	(6)
Other	—	1	(1)
Segment Adjusted EBITDA	$ 1,680	$ 1,274	$ 406

Volumes. For the year ended December 31, 2018 compared to the prior year, transported volumes reflected increases of 1,919 BBtu/d as a result of the initiation of service on the Rover pipeline; increases of 572 BBtu/d and 439 BBtu/d on the Panhandle and Trunkline pipelines, respectively, due to higher demand resulting from colder weather and increased utilization by the Rover pipeline; 375 BBtu/d on the Tiger pipeline as a result of production increases in the Haynesville Shale, and 145 BBtu/d on the Transwestern pipeline resulting from favorable market opportunities in the West, midcontinent and Waha areas from the Permian supply basin.

Segment Adjusted EBITDA. For the year ended December 31, 2018 compared to the prior year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net impacts of the following:

- an increase of $359 million associated with the Rover pipeline with increases of $485 million in revenues, $105 million in net operating expenses and $21 million in selling, general and administrative expenses and other; and
- an aggregate increase of $66 million in revenues, excluding the incremental revenue related to the Rover pipeline discussed above, primarily due to capacity sold at higher rates on the Transwestern and Panhandle pipelines; partially offset by
- an increase of $11 million in operating expenses, excluding the incremental expenses related to the Rover pipeline discussed above, primarily due to increases in maintenance project costs due to scope and level of activity; and
- a decrease of $6 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to lower margins on MEP due to lower rates on renewals of expiring long term contracts.

Midstream

	Years Ended December 31,		
	2018	2017	Change
Gathered volumes (BBtu/d)	12,126	10,956	1,170
NGLs produced (MBbls/d)	540	472	68
Equity NGLs (MBbls/d)	29	27	2
Revenues	$ 7,522	$ 6,943	$ 579
Cost of products sold	5,145	4,761	384
Segment margin	2,377	2,182	195
Unrealized gains on commodity risk management activities	—	(15)	15
Operating expenses, excluding non-cash compensation expense	(705)	(638)	(67)
Selling, general and administrative expenses, excluding non-cash compensation expense	(81)	(78)	(3)
Adjusted EBITDA related to unconsolidated affiliates	33	28	5
Other	3	2	1
Segment Adjusted EBITDA	$ 1,627	$ 1,481	$ 146

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Volumes. Gathered volumes and NGL production increased during the year ended December 31, 2018 compared to the prior year primarily due to increases in the North Texas, Permian and Northeast regions, partially offset by smaller declines in other regions.

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

	Years Ended December 31,		
	2018	2017	Change
Gathering and processing fee-based revenues	$ 1,807	$ 1,690	$ 117
Non-fee based contracts and processing (excluding unrealized gains and losses)	570	477	93
Unrealized gains on commodity risk management activities	—	15	(15)
Total segment margin	$ 2,377	$ 2,182	$ 195

Segment Adjusted EBITDA. For the year ended December 31, 2018 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 $117 million in fee-based margin due to growth in the North Texas, Permian and Northeast regions, offset by declines in the Ark-La-Tex and midcontinent/Panhandle regions;
- an increase of $60 million in non fee-based margin due to increased throughput volume in the North Texas and Permian regions;
- an increase of $33 million in non fee-based margin due to higher crude oil and NGL prices; and
- an increase of $5 million in Adjusted EBITDA related to unconsolidated affiliates due to higher earnings from our Aqua, Mi Vida and Ranch joint ventures; partially offset by
- an increase of $67 million in operating expenses primarily due to increases of $20 million in outside services, $19 million in materials, $8 million in maintenance project costs, $7 million in ad valorem taxes, $6 million in employee costs and $6 million in office expenses; and
- an increase of $3 million in selling, general and administrative expenses due to higher professional fees.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2018	2017	Change
NGL transportation volumes (MBbls/d)	1,027	863	164
Refined products transportation volumes (MBbls/d)	621	624	(3)
NGL and refined products terminal volumes (MBbls/d)	812	783	29
NGL fractionation volumes (MBbls/d)	527	427	100
Revenues	$ 11,123	$ 8,648	$2,475
Cost of products sold	8,462	6,508	1,954
Segment margin	2,661	2,140	521
Unrealized gains on commodity risk management activities	(86)	(26)	(60)
Operating expenses, excluding non-cash compensation expense	(604)	(478)	(126)
Selling, general and administrative expenses, excluding non-cash compensation expense	(74)	(64)	(10)
Adjusted EBITDA related to unconsolidated affiliates	82	68	14
Other	—	1	(1)
Segment Adjusted EBITDA	$ 1,979	$ 1,641	$338

Volumes. For the year ended December 31, 2018 compared to the prior year, NGL transportation volumes increased primarily due to increased volumes from the Permian region resulting from a ramp up in production from existing customers, higher throughput volumes on Mariner West driven by end-user facility constraints in the prior year and higher throughput from Mariner South resulting from increased export volumes.

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Refined products transportation volumes decreased for the year ended December 31, 2018 compared to prior year, primarily due to timing of turnarounds at third-party refineries in the Midwest and Northeast regions.
NGL and Refined products terminal volumes increased for the year ended December 31, 2018 compared to prior year, primarily due to more volumes loaded at our Nederland terminal as propane export demand increased and higher throughput volumes at our refined products terminals in the Northeast.
Average volumes fractionated at our Mont Belvieu, Texas fractionation facility increased for the year ended December 31, 2018 compared to the prior year primarily due to increased volumes from the Permian region, as well as an increase in fractionation capacity as our fifth fractionator at Mont Belvieu came online in July 2018.
Segment Margin. The components of our NGL and refined products transportation and services segment margin were as follows:

	Years Ended December 31,		
	2018	2017	Change
Fractionators and Refinery services margin	$ 592	$ 488	$ 104
Transportation margin	1,233	990	243
Storage margin	211	214	(3)
Terminal Services margin	413	351	62
Marketing margin	126	71	55
Unrealized gains on commodity risk management activities	86	26	60
Total segment margin	$ 2,661	$ 2,140	$ 521

Segment Adjusted EBITDA. For the year ended December 31, 2018 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 $243 million primarily due to a $216 million increase resulting from increased producer volumes from the Permian region on our Texas NGL pipelines, a $31 million increase due to higher throughput volumes on Mariner West driven by end-user facility constraints in the prior period, a $15 million increase resulting from a reclassification between our transportation and fractionation margins, a $9 million increase due to higher throughput volumes from the Barnett region, a $5 million increase due to higher throughput volumes on Mariner South due to system downtime in the prior period and a $4 million increase in prior period customer credits. These increases were partially offset by a $16 million decrease resulting from lower throughput volumes on Mariner East 1 due to system downtime in 2018, a $14 million decrease due to lower throughput volumes from the Southeast Texas region and a $7 million decrease resulting from the timing of deficiency fee revenue recognition;
- an increase in fractionation and refinery services margin of $104 million primarily due to a $106 million increase resulting from the commissioning of our fifth fractionator in July 2018, a $9 million increase from throughput revenue at our Mariner South export facility and a $7 million increase from blending gains as a result of improved market pricing. These increases were partially offset by a $16 million decrease resulting from a reclassification between our transportation and fractionation margins and a $2 million decrease from higher affiliate storage fees paid;
- an increase in terminal services margin of $62 million due to a $36 million increase resulting from a change in the classification of certain customer reimbursements previously recorded in operating expenses, a $14 million increase at our Nederland terminal due to increased export demand and a $12 million increase due to higher throughput at our Marcus Hook Industrial Complex. These increases were partially offset by lower terminal throughput fees in part due to the sale of one of our terminals in April 2017;
- an increase in marketing margin of $55 million due to a $48 million increase from our butane blending operations and a $22 million increase in sales of NGLs and other products at our Marcus Hook Industrial Complex due to more favorable market prices. These increases were partially offset by a $15 million decrease from the timing of optimization gains from our Mont Belvieu fractionators; and
- an increase of $14 million to adjusted EBITDA related to unconsolidated affiliates due to improved contributions from our unconsolidated refined products joint venture interests; partially offset by
- an increase of $126 million in operating expenses primarily due to a $30 million increase in costs to operate our fractionators and a $20 million increase in operating costs on our NGL pipelines as a result of higher throughput and

the commissioning of our fifth fractionator in July 2018, a $36 million increase resulting from a change in the classification of certain customer reimbursements previously recorded as a reduction to operating expenses that are now classified as revenue following the adoption of ASC 606 on January 1, 2018, increases of $24 million and $7 million to operating costs at our Marcus Hook and Nederland terminals, respectively, as a result of significantly higher volumes through both terminals in 2018, an $8 million increase to environmental reserves and a $1 million increase to overhead allocations and maintenance repairs performed on our refinery services assets; and

- an increase of $10 million in selling, general and administrative expenses primarily due to a $6 million increase in overhead costs allocated to the segment, a $2 million increase in legal fees, a $1 million increase in management fees previously recorded in operating expenses and a $1 million increase in employee costs.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2018	2017	Change
Crude Transportation Volumes (MBbls/d)	4,172	3,538	634
Crude Terminals Volumes (MBbls/d)	2,096	1,928	168
Revenue	$ 17,332	$ 11,703	$ 5,629
Cost of products sold	14,439	9,826	4,613
Segment margin	2,893	1,877	1,016
Unrealized losses on commodity risk management activities	55	1	54
Operating expenses, excluding non-cash compensation expense	(547)	(430)	(117)
Selling, general and administrative expenses, excluding non-cash compensation expense	(86)	(82)	(4)
Adjusted EBITDA related to unconsolidated affiliates	15	13	2
Segment Adjusted EBITDA	$ 2,330	$ 1,379	$ 951

Segment Adjusted EBITDA. For the year ended December 31, 2018 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 $1.07 billion in segment margin (excluding unrealized losses on commodity risk management activities) primarily due to the following: a $586 million increase resulting from placing the Bakken pipeline in service in the second quarter of 2017; a $266 million increase resulting from higher throughput on our Texas crude pipeline system primarily due to increased production from Permian producers; and a $189 million increase (excluding a net change of $54 million in unrealized losses on commodity risk management activities) from our crude oil acquisition and marketing business primarily resulting from improved basis differentials between the Permian and Bakken producing regions to our Nederland terminal on the Texas gulf coast; and a $28 million increase primarily from higher throughput and ship loading fees at our Nederland terminal; and
- an increase of $2 million in Adjusted EBITDA related to unconsolidated affiliates due to increased jet fuel sales from our joint ventures; partially offset by
- an increase of $117 million in operating expenses primarily due to a $67 million increase to throughput related costs on existing assets; a $36 million increase resulting from placing the Bakken pipeline in service in the second quarter of 2017; a $26 million increase resulting from the addition of certain joint venture transportation assets in the second quarter of 2017; and a $5 million increase from ad valorem taxes; partially offset by an $17 million decrease in insurance and environmental related expenses; and
- an increase of $4 million in selling, general and administrative expenses primarily due to increases associated with placing our Bakken Pipeline in service in the second quarter of 2017.

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Investment in Sunoco LP

	Years Ended December 31, 2018	2017	Change
Revenues	$16,994	$11,723	$5,271
Cost of products sold	15,872	10,615	5,257
Segment margin	1,122	1,108	14
Unrealized (gains) losses on commodity risk management activities	6	(3)	9
Operating expenses, excluding non-cash compensation expense	(435)	(456)	21
Selling, general and administrative, excluding non-cash compensation expense	(129)	(116)	(13)
Inventory fair value adjustments	85	(24)	109
Adjusted EBITDA from discontinued operations	(25)	223	(248)
Other, net	14	—	14
Segment Adjusted EBITDA	$638	$732	$(94)

The Investment in Sunoco LP segment reflects the consolidated results of Sunoco LP.

Segment Adjusted EBITDA. For the year ended December 31, 2018 compared to the prior year, Segment Adjusted EBITDA related to the Investment in Sunoco LP segment decreased due to the net impacts of the following:

- a decrease of $248 million in Adjusted EBITDA from discontinued operations primarily due to Sunoco LP's retail divestment in January 2018; partially offset by
- an increase of $109 million in inventory fair value adjustments due to changes in fuel prices between periods;
- an increase of $14 million in margin primarily due to an increase in rental income as a result of the increase in commission agent sites in the current year, offset by decreases in the gross profit on motor fuel sales; and
- a net decrease of $8 million in operating and selling, general and administrative expenses primarily due to decreased rent expense.

Investment in USAC

	Years Ended December 31, 2018	2017	Change
Revenues	$ 508	$ —	$ 508
Cost of products sold	67	—	67
Segment margin	441	—	441
Operating expenses, excluding non-cash compensation expense	(110)	—	(110)
Selling, general and administrative, excluding non-cash compensation expense	(50)	—	(50)
Other, net	8	—	8
Segment Adjusted EBITDA	$ 289	$ —	$ 289

Amounts reflected above for the year ended December 31, 2018 represents the results of operations for USAC from April 2, 2018, the date ET obtained control of USAC, through December 31, 2018. Changes between periods are due to the consolidation of USAC beginning April 2, 2018.

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All Other

	Years Ended December 31,		
	2018	2017	Change
Revenue	$ 2,228	$ 2,901	$ (673)
Cost of products sold	2,006	2,509	(503)
Segment margin	222	392	(170)
Unrealized gains on commodity risk management activities	(2)	(11)	9
Operating expenses, excluding non-cash compensation expense	(56)	(117)	61
Selling, general and administrative expenses, excluding non-cash compensation expense	(87)	(103)	16
Adjusted EBITDA related to unconsolidated affiliates	1	45	(44)
Other and eliminations	(2)	13	(15)
Segment Adjusted EBITDA	$ 76	$ 219	$ (143)

Amounts reflected in our all other segment primarily include:

- our natural gas marketing operations;
- our wholly-owned natural gas compression operations;
- a non-controlling interest in PES. Prior to PES's reorganization in August 2018, ETO's 33% interest in PES was reflected as an unconsolidated affiliate; subsequent the August 2018 reorganization, ETO holds an approximately 8% interest in PES and no longer reflects PES as an affiliate; and
- our investment in coal handling facilities.

Segment Adjusted EBITDA. For the year ended December 31, 2018 compared to the prior year, Segment Adjusted EBITDA decreased due to the net impact of the following:

- a decrease of $98 million due to the contribution of CDM to USAC in April 2018, subsequent to which CDM is reflected in the Investment in USAC segment;
- a decrease of $38 million in Adjusted EBITDA related to unconsolidated affiliates from our investment in PES primarily due to our lower ownership in PES subsequent to its reorganization, which resulted in PES no longer being reflected as an affiliate beginning in the third quarter of 2018;
- a decrease of $4 million due to merger and acquisition expenses related to the Energy Transfer Merger in 2018; and
- a decrease of $15 million due to a one-time fee received from a joint venture affiliate in 2017; partially offset by
- an increase of $7 million due to lower transport fees resulting from the expiration of a capacity commitment on Trunkline pipeline;
- an increase of $6 million due to a decrease in losses from mark-to-market of physical system gas; and
- an increase of $7 million due to increased margin from ETO's compression equipment business.

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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	1,274	1,297	(23)
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
Investment in Sunoco LP	732	665	67
All other	219	193	26
Total	7,352	6,231	1,121
Depreciation, depletion and amortization	(2,541)	(2,201)	(340)
Interest expense, net	(1,575)	(1,478)	(97)
Gains on acquisitions	—	83	(83)
Impairment losses	(1,039)	(1,040)	1
Losses on interest rate derivatives	(37)	(12)	(25)
Non-cash compensation expense	(99)	(93)	(6)
Unrealized (gains) losses on commodity risk management activities	59	(136)	195
Inventory valuation adjustments	24	97	(73)
Losses on extinguishments of debt	(42)	—	(42)
Adjusted EBITDA related to unconsolidated affiliates	(716)	(675)	(41)
Equity in earnings of unconsolidated affiliates	144	270	(126)
Impairment of investment in an unconsolidated affiliate	(313)	(308)	(5)
Adjusted EBITDA related to discontinued operations	(223)	(199)	(24)
Other, net	154	117	37
Income before income tax benefit	1,148	656	492
Income tax benefit from continuing operations	1,804	255	1,549
Income from continuing operations	2,952	911	2,041
Loss from discontinued operations, net of income taxes	(177)	(462)	285
Net income	$ 2,775	$ 449	$2,326

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.

Interest Expense, Net. Interest expense, net of capitalized interest, increased primarily due to an increases of $49 million recognized by the Partnership primarily due to 2017 debt issuances and $48 million recognized by Sunoco LP primarily due to increased term loan borrowings and the issuance of senior notes.

Gains on acquisitions. The Partnership recorded gains of $83 million in connection with recent acquisitions during 2016, including $41 million related to the purchase of the remaining interest in SunVit.

Impairment Losses. During the year ended December 31, 2017, the Partnership recorded goodwill impairments of $223 million related to the compression business, $229 million related to Panhandle, $262 million related to the interstate transportation and storage segment and $79 million related to the NGL and refined products transportation and services segment. Sunoco LP recognized goodwill impairments of $387 million in 2017, of which $102 million was allocated to continuing operations. In

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addition, 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, we recorded goodwill impairments of $638 million in the interstate transportation and storage segment and $32 million in the midstream segment. Sunoco LP recognized goodwill impairments of $641 million, of which $227 million was allocated to continuing operations. 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. 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 decrease in value.

Unrealized (Gains) 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 Sunoco LP 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. 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.

Adjusted EBITDA Related to Discontinued Operations. Amounts were related to the operations of Sunoco LP’s retail business that was classified as held for sale.

Other, net. Other, net in 2017 and 2016 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 $1.78 billion in December 2017. For the year ended December 31, 2016, the Partnership recorded an income tax benefit due to pre-tax losses at its corporate subsidiaries.

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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)
Other	77	46	31
Total equity in earnings of unconsolidated affiliates	$ 144	$ 270	$ (126)
Adjusted EBITDA related to unconsolidated affiliates[2]:			
Citrus	$ 336	$ 329	$ 7
FEP	74	75	(1)
MEP	88	90	(2)
HPC	46	61	(15)
Other	172	120	52
Total Adjusted EBITDA related to unconsolidated affiliates	$ 716	$ 675	$ 41
Distributions received from unconsolidated affiliates:			
Citrus	$ 156	$ 144	$ 12
FEP	47	65	(18)
MEP	114	74	40
HPC	35	51	(16)
Other	80	69	11
Total distributions received from unconsolidated affiliates	$ 432	$ 403	$ 29

(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) 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.

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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,	
	2017	2016
Segment Margin:		
Intrastate transportation and storage	$756	$716
Interstate transportation and storage	1,131	1,166
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
Investment in Sunoco LP	1,108	1,156
All other	392	330
Intersegment eliminations	(29)	(46)
Total segment margin	9,557	8,099
Less:		
Operating expenses	2,644	2,336
Depreciation, depletion and amortization	2,541	2,201
Selling, general and administrative	568	547
Impairment losses	1,039	1,040
Operating income	$2,765	$1,975

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, 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.

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

	Years Ended December 31,		
	2017	2016	Change
Transportation fees	$ 448	$ 505	$ (57)
Natural gas sales and other (excluding unrealized gains and losses)	196	118	78
Retained fuel revenues (excluding unrealized gains and losses)	58	51	7
Storage margin, including fees (excluding unrealized gains and losses)	49	61	(12)
Unrealized gains (losses) on commodity risk management activities	5	(19)	24
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 $78 million in natural gas sales and other primarily due to higher realized gains from pipeline optimization activity;
- an increase of $7 million in retained fuel sales 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; partially offset by
- a decrease of $57 million in transportation fees 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 $12 million in storage margin due to the timing of withdrawals and sales of natural gas from our Bammel storage cavern; 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.

Interstate Transportation and Storage

	Years Ended December 31,		
	2017	2016	Change
Natural gas transported (BBtu/d)	6,058	5,476	582
Natural gas sold (BBtu/d)	18	19	(1)
Revenues	$ 1,131	$ 1,166	$ (35)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(315)	(318)	3
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(41)	(40)	(1)
Adjusted EBITDA related to unconsolidated affiliates	498	494	4
Other	1	(5)	6
Segment Adjusted EBITDA	$ 1,274	$ 1,297	$ (23)

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.

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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; partially offset by
- a decrease of $3 million in operating expenses 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 of $4 million in adjusted EBITDA related to unconsolidated affiliates 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 of $6 million in other 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):	472	438	34
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, 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 Midcontinent/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	$ 1,690	$ 1,551	$ 139
Non-fee based contracts and processing (excluding unrealized gains and losses)	477	262	215
Unrealized gains (losses) on commodity risk management activities	15	(15)	30
Total segment margin	$ 2,182	$ 1,798	$ 384

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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 $65 million in non-fee based margin due to volume increases in the Permian, Northeast and South Texas regions, partially offset by volume declines in the North Texas and the Midcontinent/Panhandle regions;
- an increase of $75 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 Midcontinent/Panhandle regions;
- an increase of $64 million in fee-based revenue due to recent acquisitions, including PennTex; and
- a decrease of $6 million in selling, general and administrative expenses 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 of $17 million in operating expenses 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)	783	791	(8)
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 products 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 2016, which has a capacity of 120 MBbls/d, as well as increased producer volumes as mentioned above.

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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	$ 407	$ 81
Transportation margin	990	866	124
Storage margin	214	208	6
Terminal Services margin	351	322	29
Marketing margin	71	122	(51)
Unrealized gains (losses) on commodity risk management activities	26	(69)	95
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 of $124 million in transportation margin 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 of $81 million in fractionation and refinery services margin 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 of $29 million in terminal services margin 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 2017; and
- an increase of $6 million in storage margin 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 of $51 million in marketing margin primarily due to the timing of the recognition of margin from optimization activities;
- an increase of $37 million in operating expenses due to a $16 million increase related to the fourth fractionator being placed into service in October 2016, an $11 million increase related to higher utility expenses on our Texas NGL pipelines, 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 of $8 million in selling, general and administrative expenses due to higher allocations.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2017	2016	Change
Crude Transportation Volumes (MBbls/d)	3,538	2,652	886
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

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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 joint venture crude transportation assets;
- an increase of $90 million from existing transportation 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; partially 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, respectively, an increase of $46 million due to higher utilities, line testing, and environmental costs from existing transport assets and 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.

Investment in Sunoco LP

	Years Ended December 31,		
	2017	2016	Change
Revenues	$11,723	$9,986	$1,737
Cost of products sold	10,615	8,830	1,785
Segment margin	1,108	1,156	(48)
Unrealized (gains) losses on commodity risk management activities	(3)	5	(8)
Operating expenses, excluding non-cash compensation expense	(456)	(455)	(1)
Selling, general and administrative, excluding non-cash compensation expense	(116)	(143)	27
Inventory valuation adjustments	(24)	(97)	73
Adjusted EBITDA from discontinued operations	223	199	24
Segment Adjusted EBITDA	$732	$665	$67

The Investment in Sunoco LP segment reflects the consolidated results of Sunoco LP.

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

- an increase of $18 million in gross margin (excluding a $65 million change in fair value adjustments related to inventory and unrealized gains and losses on commodity risk management activities) primarily caused by an increase in wholesale motor fuel gross profit per gallon, partially offset by a net increase in other gross profit consisting of merchandise, rental & other and retail motor fuel of $13 million;
- a decrease of $27 million in general and administrative expenses primarily due to higher costs in 2016 related to relocation, employee termination, and higher contract labor and professional fees as the Partnership transitioned offices in Philadelphia, Pennsylvania, Houston, Texas, and Corpus Christi, Texas to Dallas during 2016; and
- an increase of $24 million related to discontinued operations; partially offset by
- an increase of $1 million in other operating expenses primarily attributable to Sunoco LP's retail business which has expanded through third-party acquisitions as well as through the construction of new-to-industry sites.

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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	45	15	30
Other and eliminations	13	(13)	26
Segment Adjusted EBITDA	$ 219	$ 193	$ 26

Amounts reflected in our all other segment primarily include:

- our natural gas marketing operations;
- our wholly-owned natural gas compression operations;
- a non-controlling interest in PES, representing approximately 33% of PES' outstanding common units for the periods presented above; 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 increased due to the net impact of the following:

- an increase of $33 million in Adjusted EBITDA related to our investment in PES;
- an increase of $20 million in crude and power trading activates, primarily from the liquidation of crude inventories;
- a one-time fee of $15 million received from a joint venture affiliate; and
- a decrease of $11 million in expenses related to our compression business; partially offset by
- a decrease of $31 million from the mark-to-market of physical system gas and settled derivatives;
- an increase of $17 million in selling, general and administrative expenses primarily from higher transaction-related expenses; and
- a decrease of $15 million in income related to the termination of management fees paid by ET that ended in the first quarter of 2017.

Liquidity and Capital Resources

Our ability to satisfy our obligations and pay distributions to our preferred 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.

The Partnership currently expect capital expenditures in 2019 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$125	$175	$35	$40
Interstate transportation and storage [(1)]	175	200	140	145
Midstream	750	850	115	120
NGL and refined products transportation and services	3,100	3,200	90	100
Crude oil transportation and services [(1)]	575	650	90	100
All other (including eliminations)	125	150	50	55
Total capital expenditures	$4,850	$5,225	$520	$560

(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 expect to fund growth capital expenditures with proceeds of borrowings under credit facilities, long-term debt, the issuance of additional preferred units or a combination thereof.

As of December 31, 2018, in addition to $418 million of cash on hand, we had available capacity under the ETO Credit Facilities of $2.24 billion. Based on our current estimates, we expect to utilize capacity under the ETO Credit Facilities, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2019; 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.

Sunoco LP

Sunoco LP's primary sources of liquidity consist of cash generated from operating activities, borrowings under its $1.50 billion credit facility and the issuance of additional long-term debt or partnership units as appropriate given market conditions. At December 31, 2018, Sunoco LP had available borrowing capacity of $792 million under its revolving credit facility and $56 million of cash and cash equivalents on hand.

In 2019, Sunoco LP expects to invest approximately $90 million in growth capital expenditures and approximately $45 million on maintenance capital expenditures. Sunoco LP may revise the timing of these expenditures as necessary to adapt to economic conditions.

USAC

The compression services business is capital intensive, requiring significant investment to maintain, expand and upgrade existing operations. USAC's capital requirements have consisted primarily of, and it anticipates that its capital requirements will continue to consist primarily of, the following:

- maintenance capital expenditures, which are capital expenditures made to maintain the operating capacity of its assets and extend their useful lives, to replace partially or fully depreciated assets, or other capital expenditures that are incurred in maintaining its existing business and related operating income; and
- expansion capital expenditures, which are capital expenditures made to expand the operating capacity or operating income capacity of assets, including by acquisition of compression units or through modification of existing compression units to increase their capacity, or to replace certain partially or fully depreciated assets that were not currently generating operating income.

USAC classifies capital expenditures as maintenance or expansion on an individual asset basis. Over the long-term, USAC expects that its maintenance capital expenditure requirements will continue to increase as the overall size and age of its fleet increase.

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USAC currently plans to spend approximately $25 million in maintenance capital expenditures during 2019, including parts consumed from inventory.

Without giving effect to any equipment USAC may acquire pursuant to any future acquisitions, it currently has budgeted between $140 million and $150 million in expansion capital expenditures during 2019. As of December 31, 2018, USAC has binding commitments to purchase $108 million of additional compression units and serialized parts, all of which USAC expects to be delivered in 2019.

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 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, 2018

Cash provided by operating activities in 2018 was $7.56 billion and income from continuing operations was $4.04 billion. The difference between net income and cash provided by operating activities in 2018 primarily consisted of non-cash items totaling $3.11 billion offset by net changes in operating assets and liabilities of $117 million. The non-cash activity in 2018 consisted primarily of depreciation, depletion and amortization of $2.84 billion, impairment losses of $431 million, non-cash compensation expense of $105 million, equity in earnings of unconsolidated affiliates of $344 million, inventory valuation adjustments of $85 million, losses on extinguishment of debt of $109 million and deferred income taxes expense of $8 million. The Partnership also received distributions of $328 million from unconsolidated affiliates.

Year Ended December 31, 2017

Cash provided by operating activities in 2017 was $4.82 billion and income from continuing operations was $2.95 billion. The difference between net income and cash provided by operating activities in 2017 primarily consisted of non-cash items totaling $1.78 billion offset by net changes in operating assets and liabilities of $173 million. The non-cash activity in 2017 consisted primarily of depreciation, depletion and amortization of $2.54 billion, impairment losses of $1.04 billion, impairment of an unconsolidated affiliate of $313 million, non-cash compensation expense of $99 million, equity in earnings of unconsolidated affiliates of $144 million, inventory valuation adjustments of $24 million, losses on extinguishment of debt of $42 million and a deferred income tax benefit of $1.84 billion. The Partnership also received distributions of $297 million from unconsolidated affiliates.

Year Ended December 31, 2016

Cash provided by operating activities in 2016 was $4.21 billion and income from continuing operations was $911 million. The difference between net income and cash provided by operating activities in 2016 primarily consisted of non-cash items totaling $2.75 billion offset by net changes in operating assets and liabilities of $303 million. The non-cash activity in 2016 consisted primarily of depreciation, depletion and amortization of

$2.20 billion, impairment losses of $1.04 billion, impairment in unconsolidated affiliates of $308 million, inventory valuation adjustments of $97 million, non-cash compensation expense of $93 million, equity in earnings of unconsolidated affiliates of $270 million and a deferred income tax benefit of $174 million. The Partnership also received distributions of $268 million from unconsolidated affiliates.

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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, 2018

Cash used in investing activities in 2018 was $6.90 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $7.30 billion. Additional detail related to our capital expenditures is provided in the table below. We received $711 million of cash proceeds related to the USAC acquisition and paid $429 million in cash for all other acquisitions. We also received $87 million of cash proceeds from the sale of assets.

Year Ended December 31, 2017

Cash used in investing activities in 2017 was $5.61 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $8.42 billion. Additional detail related to our capital expenditures is provided in the table below. We paid $280 million in cash related to the acquisition of PennTex's remaining noncontrolling interest and $303 million in cash for all other acquisitions. We received $2.00 billion in cash related to the Bakken equity sale to MarEn Bakken Company LLC, $1.48 billion in cash related to the Rover equity sale to Blackstone Capital Partners and $135 million in cash in distributions from unconsolidated affiliates.

Year Ended December 31, 2016

Cash used in investing activities in 2016 was $8.96 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $7.68 billion. Additional detail related to our capital expenditures is provided in the table below. We paid net cash of $1.40 billion for acquisitions, including the acquisition of a noncontrolling interest.

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The following is a summary of the Partnership's capital expenditures (including only our proportionate share of the Bakken, Rover and Bayou Bridge pipeline projects and net of contributions in aid of construction costs) by period:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Year Ended December 31, 2018:			
Intrastate transportation and storage	$311	$ 33	$344
Interstate transportation and storage	695	117	812
Midstream	1,026	135	1,161
NGL and refined products transportation and services	2,303	78	2,381
Crude oil transportation and services	414	60	474
Investment in Sunoco LP	72	31	103
Investment in USAC (1)	182	23	205
All other (including eliminations)	117	33	150
Total capital expenditures	$5,120	$ 510	$5,630
Year Ended December 31, 2017:			
Intrastate transportation and storage	$155	$ 20	$175
Interstate transportation and storage	645	83	728
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
Investment in Sunoco LP (2)	129	48	177
All other (including eliminations)	196	72	268
Total capital expenditures	$5,601	$ 479	$6,080
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
Investment in Sunoco LP (2)	333	106	439
All other (including eliminations)	109	51	160
Total capital expenditures	$5,775	$ 474	$6,249

(1) Amounts related to USAC capital expenditures (net of contributions in aid of construction costs) for 2018 are subsequent to the close of the CDM Contribution on April 2, 2018 as discussed in "Recent Developments."

(2) Amounts related to Sunoco LP's capital expenditures include capital expenditures related to discontinued operations.

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, 2018

Cash used in financing activities was $3.31 billion in 2018. We received $58 million in net proceeds from common unit offerings and $867 million in net proceeds from the issuance of preferred units. Net proceeds from the offerings were used to repay

outstanding borrowings under the ETO Credit Facilities, to fund capital expenditures and acquisitions, as well as for general partnership purposes. In 2018, we had a net increase in in our debt level of $801 million. In 2018, we paid distributions of $4.56 billion to our partners and we paid distributions of $1.17 billion to noncontrolling interests, including predecessor distributions. In addition, we received capital contributions from noncontrolling interests of $649 million. During 2018, we incurred debt issuance costs of $162 million and our subsidiaries repurchased $300 million of common units in cash. Additionally, in 2018, our subsidiary received $465 million related to redeemable noncontrolling interests.

Year Ended December 31, 2017

Cash provided by financing activities was $572 million in 2017. We received $2.28 billion in net proceeds from common unit offerings, $1.48 billion in net proceeds from the issuance of preferred units and we received $333 million in net proceeds from predecessor equity offerings. Net proceeds from the offerings and issuances were used to repay outstanding borrowings under the ETO Credit Facility, to fund capital expenditures and acquisitions as well as for general partnership purposes. In 2017, we had a net increase in our debt level of $421 million. In addition, we incurred debt issuance costs of $83 million. In 2017, we paid distributions of $3.47 billion to our partners and distributions of $714 million to noncontrolling interests, including predecessor distributions. In addition, we received capital contributions from noncontrolling interests of $1.21 billion.

Year Ended December 31, 2016

Cash provided by financing activities was $5.02 billion in 2016. We received $1.10 billion in net proceeds from common unit offerings, our subsidiaries received $1.39 billion in net proceeds from the issuance of common units and we received $132 million in net proceeds from predecessor equity offerings. Net proceeds from the offerings were used to repay outstanding borrowings under the ETO 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 $6.41 billion. In addition, we incurred debt issuance costs of $52 million. In 2016, we paid distributions of $3.54 billion to our partners and we paid distributions of $726 million to noncontrolling interests, including predecessor distributions. In addition, we received capital contributions from noncontrolling interests of $236 million.

Discontinued Operations

Following is a summary of activities related to discontinued operations by period:

Year Ended December 31, 2018

Cash provided by discontinued operations was $2.73 billion for the year ended December 31, 2018 resulting from cash used in operating activities of $484 million, cash provided by investing activities of $3.21 billion and changes in cash included in current assets held for sale of $11 million.

Year Ended December 31, 2017

Cash provided by discontinued operations was $93 million for the year ended December 31, 2017 resulting from cash provided by operating activities of $136 million, cash used in investing activities of $38 million and changes in cash included in current assets held for sale of $5 million.

Year Ended December 31, 2016

Cash used in discontinued operations was $385 million for the year ended December 31, 2016 resulting from cash provided by operating activities of $93 million, cash used in investing activities of $483 million and changes in cash included in current assets held for sale of $5 million.

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Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	December 31, 2018	December 31, 2017
ETO Senior Notes	$28,755	$27,005
Transwestern Senior Notes	575	575
Panhandle Senior Notes	385	785
Sunoco LP Senior Notes, Term Loan and lease-related obligations	2,307	3,556
USAC Senior Notes due April 1, 2026	725	—
Revolving credit facilities:		
ETO $5.00 billion Revolving Credit Facility due December 2023	3,694	2,292
ETO $1.00 billion 364-Day Credit Facility due November 2019	—	50
Sunoco LP $1.50 billion Revolving Credit Facility due July 2023	700	—
Sunoco LP $1.50 billion Revolving Credit Facility due September 2019	—	765
USAC $1.60 billion Revolving Credit Facility due April 2023	1,050	—
Bakken $2.50 billion Credit Facility due August 2019	2,500	2,500
Other long-term debt	7	8
Unamortized premiums, net of discounts and fair value adjustments	31	61
Deferred debt issuance costs	(221)	(213)
Total debt	40,508	37,384
Less: current maturities of long-term debt	2,655	413
Long-term debt, less current maturities	$37,853	$36,971

The terms of our consolidated indebtedness and that of our subsidiaries are described in more detail below and in Note 5 to our consolidated financial statements.

Recent Transactions

ETO 2019 Senior Notes Offering and Redemption

In January 2019, ETO issued the following senior notes:

- $750 million aggregate principal amount of 4.50% senior notes due 2024;
- $1.50 billion aggregate principal amount of 5.25% senior notes due 2029; and
- $1.75 billion aggregate principal amount of 6.25% senior notes due 2049.

The $3.96 billion net proceeds from the offering were used to make an intercompany loan to ET (which ET used to repay its term loan in full), for general partnership purposes and to redeem at maturity all of the following:

- ETO’s $400 million aggregate principal amount of 9.70% senior notes due March 15, 2019;
- ETO’s $450 million aggregate principal amount of 9.00% senior notes due April 15, 2019; and
- Panhandle’s $150 million aggregate principal amount of 8.125% senior notes due June 1, 2019.

ETO 2018 Senior Notes Offering and Redemption

In June 2018, ETO issued the following senior notes:

- $500 million aggregate principal amount of 4.20% senior notes due 2023;
- $1.00 billion aggregate principal amount of 4.95% senior notes due 2028;
- $500 million aggregate principal amount of 5.80% senior notes due 2038; and
- $1.00 billion aggregate principal amount of 6.00% senior notes due 2048.

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The $2.96 billion net proceeds from the offering were used to repay borrowings outstanding under ETO's revolving credit facility, for general partnership purposes and to redeem at maturity all of the following senior notes:
- ETO's $650 million aggregate principal amount of 2.50% senior notes due June 15, 2018;
- Panhandle's $400 million aggregate principal amount of 7.00% senior notes due June 15, 2018; and
- ETO's $600 million aggregate principal amount of 6.70% senior notes due July 1, 2018.

The aggregate amount paid to redeem these notes was approximately $1.65 billion.

Sunoco LP Senior Notes Offering

On January 23, 2018, Sunoco LP completed a private offering of $2.2 billion of senior notes, comprised of $1.0 billion in aggregate principal amount of 4.875% senior notes due 2023, $800 million in aggregate principal amount of 5.500% senior notes due 2026 and $400 million in aggregate principal amount of 5.875% senior notes due 2028.

Sunoco LP used the proceeds from the private offering, along with proceeds from its retail divestment to:
- redeem in full its existing senior notes, comprised of $800 million in aggregate principal amount of 6.250% senior notes due 2021, $600 million in aggregate principal amount of 5.500% senior notes due 2020 and $800 million in aggregate principal amount of 6.375% senior notes due 2023;
- repay in full and terminate its term loan;
- pay all closing costs in connection with its retail divestment;
- redeem the outstanding Sunoco LP Series A Preferred Units; and
- repurchase 17,286,859 Sunoco LP common units owned by ETO.

On December 3, 2018, Sunoco LP completed an exchange of the notes for registered notes with substantially identical terms.

USAC Senior Notes Offerings

In March 2018, USAC completed a private offering of $725 million aggregate principal amount of senior notes that mature on April 1, 2026. The notes accrue interest from March 23, 2018 at the rate of 6.875% per year. Interest on the notes will be payable semi-annually in arrears on each April 1 and October 1, commencing on October 1, 2018. On January 14, 2019, USAC completed an exchange of these notes for registered notes with substantially identical terms.

In February 2019, USAC announced the offering of $750 million aggregate principal amount of senior unsecured notes due 2027 in a private placement to eligible purchasers. USAC intends to use the net proceeds from this offering to repay a portion of its existing borrowings under the USAC credit facility and for general partnership purposes.

Credit Facilities and Commercial Paper

ETO Credit Facilities

Borrowings under the ETO Credit Facilities are unsecured and initially guaranteed by Sunoco Logistics Partners Operations L.P. Borrowings under the ETO 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 ETO Credit Facilities.

We typically repay amounts outstanding under the ETO Credit Facilities with proceeds from 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 ETO 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 ETO 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 ETO Credit Facilities with proceeds from unit offerings or long-term note offerings.

ETO's revolving credit facility (the "ETO Five-Year Credit Facility") previously allowed for unsecured borrowings up to $4.00 billion and matured in December 2022. On October 19, 2018, the ETO Five-Year Credit Facility was amended to increase the borrowing capacity by $1.00 billion, to $5.00 billion, and to extend the maturity date to December 1, 2023. The ETO Five-Year Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased up to $6.00 billion under certain conditions.

As of December 31, 2018, the ETO Five-Year Credit Facility had $3.69 billion outstanding, of which $2.34 billion was commercial paper. The amount available for future borrowings was $1.24 billion after taking into account letters of credit of $63 million. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 3.57%.

ETO's 364-day revolving credit facility (the "ETO 364-Day Facility") previously allowed for unsecured borrowings up to $1.00 billion and matured on November 30, 2018. On October 19, 2018, the ETO 364-Day Facility was amended to extend the maturity date to November 29, 2019. As of December 31, 2018, the ETO 364-Day Facility had no outstanding borrowings.

Bakken Credit Facility

In August 2016, ETO and Phillips 66 completed project-level financing of the Bakken pipeline. The $2.50 billion credit facility matures in August 2019 (the "Bakken Credit Facility"). As of December 31, 2018, the Bakken Credit Facility had $2.50 billion of outstanding borrowings, all of which has been reflected in current maturities of long-term debt on the Partnership's consolidated balance sheet included in "Item 8. Financial Statements and Supplementary Data." The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 4.27%.

Sunoco LP Credit Facility

As of December 31, 2018, the Sunoco LP Credit Facility had $700 million outstanding borrowings and $8 million in standby letters of credit. The unused availability on the revolver at December 31, 2018 was $792 million. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 4.45%.

USAC Credit Facility

As of December 31, 2018, USAC had $1.05 billion of outstanding borrowings and no outstanding letters of credit under the credit agreement. As of December 31, 2018, USAC had $550 million of availability under its credit facility. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 4.69%.

Covenants Related to Our Credit Agreements

Covenants Related to ETO

The agreements relating to the ETO 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 ETO 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 ETO Credit Facilities) during certain Defaults (as defined in the ETO Credit Facilities) and during any Event of Default (as defined in the ETO 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 ETO 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 ETO 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 ETO Five-Year Facility ranges from 0.125% to 0.300%. The applicable margin for eurodollar rate loans under the ETO 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 ETO 364-Day Facility ranges from 0.125% to 0.225%.

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The ETO 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 ETO 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 3.38 to 1 at December 31, 2018, 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 Partnership's or our subsidiaries' ability to incur additional debt and/or our ability to pay distributions to Unitholders.

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.

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Covenants Related to Sunoco LP

The Sunoco LP Credit Facility contains various customary representations, warranties, covenants and events of default, including a change of control event of default, as defined therein. Sunoco LP's Credit Facility requires Sunoco LP to maintain a Net Leverage Ratio of not more than 5.5 to 1. The maximum Net Leverage Ratio is subject to upwards adjustment of not more than 6.0 to 1 for a period not to exceed three fiscal quarters in the event Sunoco LP engages in certain specified acquisitions of not less than $50 million (as permitted under Sunoco LP's Credit Facility agreement). The Sunoco LP Credit Facility also requires Sunoco LP to maintain an Interest Coverage Ratio (as defined in the Sunoco LP's Credit Facility agreement) of not less than 2.25 to 1.

Covenants Related to USAC

The USAC Credit Facility contains covenants that limit (subject to certain exceptions) USAC's ability to, among other things:

- grant liens;
- make certain loans or investments;
- incur additional indebtedness or guarantee other indebtedness;
- merge or consolidate;
- sell our assets; or
- make certain acquisitions.

The credit facility is also subject to the following financial covenants, including covenants requiring us to maintain:

- a minimum EBITDA to interest coverage ratio of 2.5 to 1.0, determined as of the last day of each fiscal quarter; and
- a maximum funded debt to EBITDA ratio, determined as of the last day of each fiscal quarter, for the annualized trailing three months of (i) 5.75 to 1 through the end of the fiscal quarter ending March 31, 2019, (ii) 5.5 to 1 through the end of the fiscal quarter ending December 31, 2019 and (iii) 5.0 to 1 thereafter, in each case subject to a provision for increases to such thresholds by 0.50 in connection with certain future acquisitions for the six consecutive month period following the period in which any such acquisition occurs.

Compliance with our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2018.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2018:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$40,698	$ 3,505	$3,287	$11,760	$22,146
Interest on long-term debt[(1)]	25,702	2,002	3,659	3,043	16,998
Payments on derivatives	181	76	105	—	—
Purchase commitments[(2)]	2,458	2,295	121	22	20
Transportation, natural gas storage and fractionation contracts	9	8	1	—	—
Operating lease obligations	601	104	169	108	220
Service concession arrangement[(3)]	394	15	30	31	318
Other[(4)]	198	26	51	43	78
Total[(5)]	$70,241	$ 8,031	$7,423	$15,007	$39,780

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2018. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2018. 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.

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(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, 2018 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) Includes minimum guaranteed payments under service concession arrangements with New Jersey Turnpike Authority and New York Thruway Authority.

(4) 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.

(5) 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

ETO Preferred Unit Distributions

Distributions on the Partnership's Series A, Series B, Series C and Series D preferred units declared and/or paid by the Partnership during the periods presented were as follows:

Period Ended	Record Date	Payment Date	Series A [1]	Series B [1]	Series C	Series D
December 31, 2017	February 1, 2018	February 15, 2018	$15.4510*	$16.3780*	$ —	$ —
June 30, 2018	August 1, 2018	August 15, 2018	31.2500	33.1250	0.5634*	—
September 30, 2018	November 1, 2018	November 15, 2018	—	—	0.4609	0.5931*
December 31, 2018	February 1, 2019	February 15, 2019	31.2500	33.1250	0.4609	0.4766

* Represent prorated initial distributions.

(1) Series A and Series B preferred unit distributions are paid on a bi-annual basis.

Sunoco LP Cash Distributions

The following table illustrates the percentage allocations of available cash from operating surplus between Sunoco LP's common unitholders and the holder of its IDRs based on the specified target distribution levels, after the payment of distributions to Class C unitholders. The amounts set forth under "marginal percentage interest in distributions" are the percentage interests of the IDR holder and the common unitholders in any available cash from operating surplus which Sunoco LP distributes up to and including the corresponding amount in the column "total quarterly distribution per unit target amount." The percentage interests shown for common unitholders and IDR holder for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

	Marginal Percentage Interest in Distributions	
Total Quarterly Distribution Target Amount	Common Unitholders	Holder of IDRs

Minimum Quarterly Distribution	$0.4375	100%	—%
First Target Distribution	$0.4375 to $0.503125	100%	—%
Second Target Distribution	$0.503125 to $0.546875	85%	15%
Third Target Distribution	$0.546875 to $0.656250	75%	25%
Thereafter	Above $0.656250	50%	50%

Distributions on Sunoco LP's units declared and/or paid by Sunoco LP were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 5, 2016	February 16, 2016	$0.8013
March 31, 2016	May 6, 2016	May 16, 2016	0.8173
June 30, 2016	August 5, 2016	August 15, 2016	0.8255
September 30, 2016	November 7, 2016	November 15, 2016	0.8255
December 31, 2016	February 13, 2017	February 21, 2017	0.8255
March 31, 2017	May 9, 2017	May 16, 2017	0.8255
June 30, 2017	August 7, 2017	August 15, 2017	0.8255
September 30, 2017	November 7, 2017	November 14, 2017	0.8255
December 31, 2017	February 6, 2018	February 14, 2018	0.8255
March 31, 2018	May 7, 2018	May 15, 2018	0.8255
June 30, 2018	August 7, 2018	August 15, 2018	0.8255
September 30, 2018	November 6, 2018	November 14, 2018	0.8255
December 31, 2018	February 6, 2019	February 14, 2019	0.8255

USAC Cash Distributions

Subsequent to the Energy Transfer Merger and USAC Transactions described in Note 1 and Note 3, respectively, ETO owns approximately 39.7 million USAC common units and 6.4 million USAC Class B units. As of December 31, 2018, USAC had approximately 96.4 million common units outstanding. USAC currently has a non-economic general partner interest and no outstanding incentive distribution rights.

Distributions on USAC's units declared and/or paid by USAC subsequent to the USAC transaction on April 2, 2018 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
March 31, 2018	May 1, 2018	May 11, 2018	$0.5250
June 30, 2018	July 30, 2018	August 10, 2018	0.5250
September 30, 2018	October 29, 2018	November 09, 2018	0.5250
December 31, 2018	January 28, 2019	February 8, 2019	0.5250

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.

Upon the adoption of ASU 2014-09, the amount of revenue that the Partnership recognizes on certain contracts has changed, primarily due to decreases in revenue (with offsetting decreases to cost of sales) resulting from recognition of non-cash consideration as revenue when received and as cost of sales when sold to third parties. In addition, income statement reclassifications were required for fuel usage and loss allowances related to multiple segments as well as contracts deemed to be in-substance supply agreements in our midstream segment. In addition to the evaluation performed, we have made appropriate design and implementation updates to our business processes, systems and internal controls to support recognition and disclosure under the new standard.

Utilizing the practical expedients allowed under the modified retrospective adoption method, Accounting Standards Codification ("ASC") Topic 606 was only applied to existing contracts for which the Partnership has remaining performance obligations as of January 1, 2018, and new contracts entered into after January 1, 2018. ASC Topic 606 was not applied to contracts that were completed prior to January 1, 2018.

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The Partnership has elected to apply the modified retrospective method to adopt the new standard. For contracts in scope of the new revenue standard as of January 1, 2018, the cumulative effect adjustment to partners' capital was not material. The comparative information has not been restated under the modified retrospective method and continues to be reported under the accounting standards in effect for those periods.

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 information about the amount, timing, and uncertainty of cash flows arising from a lease. The update requires lessees to record virtually all leases on their balance sheets. For lessors, this amended guidance modifies the classification criteria and the accounting for sales-type and direct financing leases. In January 2018, the FASB issued Accounting Standards Update No. 2018-01 ("ASU 2018-01"), which provides an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the existing lease guidance. The Partnership plans to elect the package of transition practical expedients and will adopt this standard beginning with its first quarter of fiscal 2019 and apply it retrospectively at the beginning of the period of adoption through a cumulative-effect adjustment to retained earnings. The Partnership has performed several procedures to evaluate the impact of the adoption of this standard on the financial statements and disclosures and address the implications of Topic 842 on future lease arrangements. The procedures include reviewing all forms of leases, performing a completeness assessment over the lease population, establishing processes and controls to timely identify new and modified lease agreements, educating its employees on these new processes and controls and implementing a third-party supported lease accounting information system to account for our leases in accordance with the new standard. The Partnership is finalizing its evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements, and estimates approximately $1.0 billion of right-to-use assets and lease liabilities will be recognized in the consolidated balance sheet upon adoption, with no material impact to its consolidated statements of operations.

ASU 2017-12

In August 2017, the FASB issued Accounting Standards Update 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 expects to adopt the new rules in the first quarter of 2019 and does not expect the adoption of the new accounting rules to have a material impact on the consolidated financial statements and related disclosures.

ASU 2018-02

In February 2018, the FASB issued Accounting Standards Update No. 2018-02, Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, which allows a reclassification from accumulated other comprehensive income to partners' capital for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. The Partnership elected to early adopt this ASU in the first quarter of 2018. The effect of the adoption was not material.

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, 2018 represent the actual results in all material respects.

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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.

Lake Charles LNG's revenues from storage and re-gasification of natural gas are based on capacity reservation charges and, to a lesser extent, commodity usage charges. Reservation revenues are based on contracted rates and capacity reserved by the customers and recognized monthly. Revenues from commodity usage charges are also recognized monthly and represent the recovery of electric power charges at Lake Charles LNG's terminal.

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.

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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.

Investment in Sunoco LP

Sunoco LP’s revenues from motor fuel are recognized either at the time fuel is delivered to the customer or at the time of sale. Shipment and delivery of motor fuel generally occurs on the same day. Sunoco LP charges wholesale customers for third-party transportation costs, which are recorded net in cost of sales. Through PropCo, Sunoco LP’s wholly-owned corporate subsidiary, Sunoco LP may sell motor fuel to customers on a commission agent basis, in which Sunoco LP retains title to inventory, controls access to and sale of fuel inventory, and recognizes revenue at the time the fuel is sold to the ultimate customer. In Sunoco LP’s fuel distribution and marketing operations, Sunoco LP derives other income from rental income, propane and lubricating oils, and other ancillary product and service offerings. In Sunoco LP’s other operations, Sunoco LP derives other income from merchandise, lottery ticket sales, money orders, prepaid phone cards and wireless services, ATM transactions, car washes, movie rentals, and other ancillary product and service offerings. Sunoco LP records revenue from other retail transactions on a net commission basis when a product is sold and/or services are rendered.

Investment in USAC

USAC’s revenue from contracted compression, station, gas treating and maintenance services is recognized ratably under its fixed-fee contracts over the term of the contract as services are provided to its customers. Initial contract terms typically range from six months to five years. However, USAC usually continues to provide compression services at a specific location beyond the initial contract term, either through contract renewal or on a month-to-month or longer basis. USAC primarily enters into fixed-fee contracts whereby its customers are required to pay its monthly fee even during periods of limited or disrupted throughput. Services are generally billed monthly, one month in advance of the commencement of the service month, except for certain customers who are billed at the beginning of the service month, and payment is generally due 30 days after receipt of the invoice.

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Amounts invoiced in advance are recorded as deferred revenue until earned, at which time they are recognized as revenue. The amount of consideration USAC receives and revenue it recognizes is based upon the fixed fee rate stated in each service contract.

USAC's retail parts and services revenue is earned primarily on freight and crane charges that are directly reimbursable by its customers and maintenance work on units at its customers' locations that are outside the scope of USAC's core maintenance activities. Revenue from retail parts and services is recognized at the point in time the part is transferred or service is provided and control is transferred to the customer. At such time, the customer has the ability to direct the use of the benefits of such part or service after USAC has performed its services. USAC bills upon completion of the service or transfer of the parts, and payment is generally due 30 days after receipt of the invoice. The amount of consideration USAC receives and revenue it recognizes is based upon the invoice amount.

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 OTC commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL, crude oil and refined products. These contracts consist primarily of futures and swaps.

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; 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 $4.89 billion of goodwill on the Partnership's consolidated balance sheet as of December 31, 2018, approximately $650 million 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, 2018, the Partnership recorded the following impairments:

- a $378 million impairment was recorded related to the goodwill associated with the Partnership's Northeast operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded. These changes in assumptions reflect delays in the construction of third-party takeaway capacity in the Northeast. Additionally, the Partnership recorded asset impairments of $4 million related to our midstream operations and asset impairments $9 million related to our crude operations idle leased assets.

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- Sunoco LP also recognized a $30 million impairment charge on its contractual rights primarily due to decreases in projected future revenues and cash flows from the date the intangible asset was originally recorded.
- USAC also recognized a $9 million fixed asset impairment related to certain idle compressor assets.

During the year ended December 31, 2017, the Partnership recorded the 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 ETO. 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.
- For 2017, Sunoco LP also recognized impairments of $404 million, of which $119 million was allocated to continuing operations, as discussed further below.

During the year ended December 31, 2016, the Partnership recorded the following 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.
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For 2016, Sunoco LP also recognized impairments of $641 million, of which $227 million was allocated to continuing operations, as discussed further below.

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, 2018, 2017 and 2016 represented all of the goodwill within the respective reporting units.

During 2017, Sunoco LP announced the sale of a majority of the assets in its retail and Stripes reporting units. These reporting units include the retail operations in the continental United States but excludes the retail convenience store operations in Hawaii that comprise the Aloha reporting unit. Upon the classification of assets and related liabilities as held for sale, Sunoco LP's management applied the measurement guidance in ASC 360, Property, Plant and Equipment, to calculate the fair value less cost to sell of the disposal group. In accordance with ASC 360-10-35-39, Sunoco LP's management first tested the goodwill included within the disposal group for impairment prior to measuring the disposal group's fair value less the cost to sell. In the determination of the classification of assets held for sale and the related liabilities, Sunoco LP's management allocated a portion of the goodwill balance previously included in the Sunoco LP retail and Stripes reporting units to assets held for sale based on the relative fair values of the business to be disposed of and the portion of the respective reporting unit that will be retained in accordance with ASC 350-20-40-3.

Sunoco LP recognized goodwill impairments of $387 million in 2017, of which $102 million was allocated to continuing operations, primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded.

Additionally, Sunoco LP performed impairment tests on its indefinite-lived intangible assets during the fourth quarter of 2017 and recognized $13 million and $4 million impairment charge on their contractual rights and liquor licenses primarily due to decreases in projected future revenues and cash flows from the date the intangible asset was originally recorded.

For the year ended December 31, 2016, Sunoco LP recognized goodwill impairments of $641 million, of which $227 million was allocated to continuing operations, primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded.

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, 2018 and 2017, 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 AROs 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 AROs related to Sunoco, Inc.'s pipeline assets and storage tanks, for which it is not possible to estimate whether or when the AROs will be settled. Consequently, these AROs cannot be measured at this time. Sunoco LP has AROs related to the estimated future cost to remove underground storage tanks.
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 $106 million and $103 million and were reflected as property, plant and equipment on our consolidated balance sheet as of December 31, 2018 and 2017, respectively. In addition, other non-current assets on the Partnership's consolidated balance sheet included $26 million and $21 million of legally restricted funds for the purpose of settling AROs as of December 31, 2018 and 2017, 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 10 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. The Partnership’s consolidated balance sheet reflected $337 million in environmental accruals as of December 31, 2018.

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. ETO 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 $768 million have been included in ETO’s consolidated balance sheet as of December 31, 2018. The state NOL carryforward benefits of $213 million ($168 million net of federal benefit) begin to expire in 2019 with a substantial portion expiring between 2032 and 2038. The federal NOLs of $2.60 billion ($546 million in benefits) will expire in 2031 and 2037 if attributable to tax years prior to 2018. Any federal NOL generated in 2018 and future years can be carried forward indefinitely. Federal alternative minimum tax credit carryforwards of $31 million remained at December 31, 2018. We have determined that a valuation allowance totaling $124 million ($98 million net of federal income tax effects) is required for the state NOLs at December 31, 2018 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 “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;

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- 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

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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 futures and swaps to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in margins for certain refined products and to lock in the price of a portion of natural gas purchases or sales. 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.

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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, 2018			December 31, 2017		
	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	468	$ —	$ —	1,078	$ —	$ —
Basis Swaps IFERC/NYMEX[(1)]	16,845	7	1	48,510	2	1
Options – Puts	10,000	—	—	13,000	—	—
Power (Megawatt):						
Forwards	3,141,520	6	8	435,960	1	1
Futures	56,656	—	—	(25,760)	—	—
Options – Puts	18,400	—	—	(153,600)	—	1
Options – Calls	284,800	1	—	137,600	—	—
Crude (MBbls) – Futures	—	—	—	—	1	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(30,228)	(52)	13	4,650	(13)	4
Swing Swaps IFERC	54,158	12	—	87,253	(2)	1
Fixed Swaps/Futures	(1,068)	19	1	(4,390)	(1)	2
Forward Physical Contracts	(123,254)	(1)	32	(145,105)	6	41
NGL (MBbls) – Forwards/Swaps	(2,135)	67	67	(2,493)	5	16
Crude (MBbls) – Forwards/Swaps	20,888	(60)	29	9,237	(4)	9
Refined Products (MBbls) – Futures	(1,403)	(8)	6	(3,901)	(27)	4
Corn (thousand bushels)	(1,920)	—	1	1,870	—	—
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(17,445)	(4)	—	(39,770)	(2)	—
Fixed Swaps/Futures	(17,445)	(10)	6	(39,770)	14	11

(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, 2018, we had $8.54 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $85 million annually; however, our actual change in interest expense

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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 (dollar amounts presented in millions):

Term	Type[(1)]	Notional Amount Outstanding December 31, 2018	Notional Amount Outstanding December 31, 2017
July 2018 [(2)]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	$ —	$ 300
July 2019 [(2)]	Forward-starting to pay a fixed rate of 3.56% and receive a floating rate	400	300
July 2020 [(2)]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	400
July 2021 [(2)]	Forward-starting to pay a fixed rate of 3.55% and receive a floating rate	400	—
December 2018	Pay a floating rate and receive a fixed rate of 1.53%	—	1,200
March 2019	Pay a floating rate 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 $259 million as of December 31, 2018. For the $300 million 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 less than $1 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 industrial end-users, 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.

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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, 2018.

Management's Report on Internal Control over Financial Reporting

The management of Energy Transfer Operating, 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, 2018.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2018, as stated in their report, which is included herein.

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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 Operating, L.P.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Energy Transfer Operating, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2018, 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, 2018, 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, 2018, and our report dated February 22, 2019 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 22, 2019

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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, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

Our General Partner, Energy Transfer Partners GP, L.P. ("ETP GP"), manages and directs all of our activities. 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. ET, 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, 2018, 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. Smith, Skidmore and Williams 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 President and Chief Commercial Officer of ET'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 ET 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 ET 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.

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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 2018, 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 2018. 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. Messrs. Skidmore, Smith and Williams currently serve on the Audit Committee.

Compensation and Nominating/Corporate Governance Committees

We are not required under NYSE rules to appoint a compensation committee or a nominating/corporate governance committee because we are a limited partnership; however, our Board of Directors previously established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. Prior to the Energy Transfer Merger, Michael K. Grimm and David K. Skidmore, both of whom were determined by our Board of Directors to be "independent" (as that term is defined in the applicable NYSE corporate governance standards), served on the ETO Compensation Committee. Following the Energy Transfer Merger, the duties of the ETO compensation committee have been delegated to the Compensation Committee of ET.

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.

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Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. The Chairman of our Audit Committee acts as the presiding director of such meetings.

We have established a procedure by which 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 Operating, 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 22, 2019. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	63	Chief Executive Officer and Chairman of the Board of Directors
Matthew S. Ramsey	63	Director, President and Chief Operating Officer
Thomas E. Long	62	Chief Financial Officer
Marshall S. (Mackie) McCrea, III	59	Director and ET President and Chief Commercial Officer
James M. Wright, Jr.	50	General Counsel
A. Troy Sturrock	48	Senior Vice President, Controller and Principal Accounting Officer
David K. Skidmore	63	Director
W. Brett Smith	59	Director
William P. Williams	81	Director

Messrs. Warren, McCrea and Ramsey also serve as directors of ETO's general partner. Mr. Ramsey also serves as a director of the general partner of Sunoco LP.

In connection with the closing of the Energy Transfer Merger in October 2018, Mr. Williams was appointed to the Board of Directors and Michael K. Grimm stepped down from the Board of Directors. Mr. Williams previously served as a director of ET's general partner and Mr. Grimm now serves as a director of ET's general partner.

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 ETO. Mr. Warren also serves as Chairman of the Board of Directors of ET's general partner. 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 ETO 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. 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 ET's general partner in July 2012 and as a director of ETO's general partner in November 2015. Mr. Ramsey was named President and Chief Operating Officer of ETO's general partner in November 2015. He became the Chief Operating Officer of ET's general partner in October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. Mr. Ramsey is also a director of Sunoco LP, having served as chairman of Sunoco LP's board since April 2015, and of USAC, having served on that board since April 2018. 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, and previously served as a director of RSP Permian, Inc. where he served on the audit and compensation committees. 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 has served as the Chief Financial Officer of our General Partner since April 2015 and ET's general partner 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 and as Chairman of the Board of USAC since April 2018. Mr. Long previously served 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 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 President and Chief Commercial Officer of our general partner, having served in that role since October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. Prior to that time, he had been the Group Chief Operating Officer and Chief Commercial Officer of the Energy Transfer family since November 2015. Mr. McCrea was appointed as a director of the general partner of ETO and as a a director of ET's general partner in December 2009. Prior to that, he served as President and Chief Operating Officer of ETO'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, ETO's primary operating subsidiary, after serving as Senior Vice President-Business Development and Producer Services since 1997. 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. Mr. Wright was elected General Counsel of our General Partner in December 2015. He became Executive Vice President - Legal and Chief Compliance Officer of ET's general partner in October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. 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 from May 2008 to December 2015. 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 ETO 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. He became Senior Vice President, Controller and Principal Accounting Officer of ET's general partner in October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. 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.

David K. Skidmore. Mr. Skidmore was appointed to the Board of Directors of our general partner in March 2013 and serves as a member of the Audit Committee. 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 midcontinent 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. 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

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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 Acton 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 previously served on the board of directors of Sunoco LP and as 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.

William P. Williams. Mr. Williams was appointed as a director in October 2018 and currently serves as a member of the Audit Committee. He previously served on the board of ET's general partner from March 2014 to October 2018. Mr. Williams began his career in the oil and gas industry in 1967 with Texas Power and Light Company as Manager of Pipeline Construction for Bi-Stone Fuel Company, a predecessor of Texas Utilities Fuel Company. In 1980, he was employed by Endevco as Vice President of Pipeline and Plant Construction, Engineering, and Operations. Prior to Endevco, he worked for Cornerstone Natural Gas. Mr. Williams later joined Energy Transfer as Vice President of Engineering and Operations, ending his career as Vice President of Measurement in May 2011. The member of our general partner selected Mr. Williams due to his experience in the pipeline industry and his familiarity with our business.

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. Our General Partner and its affiliates performing services for the Partnership 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 subsidiaries, and thus, our General Partner does not incur additional reimbursable costs.

Our General Partner is ultimately controlled by the general partner of ET, 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 7 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 2018.

ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner. Our General Partner is owned by ET.

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Compensation Discussion and Analysis

Named Executive Officers

ETO does not have officers or directors. Instead, we are managed by the board of directors of our General Partner, and the executive officers of our General Partner perform all of ETO's management functions. In addition, our executive officers are also executive officers of ET. The board of directors of our General Partner does not have a separate compensation committee. Therefore, we do not administer any policies or programs relating to the compensation of ET's named executive officers. The compensation of our executive officers is administered by the compensation committee of the board of directors of ET's general partner (the "ET Compensation Committee"). This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officers of ET's General Partner as set forth below. Compensation amounts discussed herein include all compensation paid to ET's named executive officers, including amounts attributable to services performed for us. The persons we refer to in this discussion as the "named executive officers" are the following:

- Kelcy L. Warren, Chairman and Chief Executive Officer;
- Thomas E. Long, Chief Financial Officer;
- Marshall S. (Mackie) McCrea, III, President and Chief Commercial Officer;
- Matthew S. Ramsey, Chief Operating Officer; and
- Thomas P. Mason, Executive Vice President, General Counsel and President — LNG.

ET's General Partner's Philosophy for Compensation of Executives

In general, the philosophy of ET's General Partner for executive compensation 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. ET's General Partner 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. ET's General Partner believes the incentive-based balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of ET's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of its named executive officers to the success of ET and the Partnership 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 ET's equity incentive plan(s) or the equity incentive programs of Sunoco LP, as applicable based on the allocation of the named executive officers' award, which awards are intended to provide a longer term incentive and retention value to its key employees to focus their efforts on increasing the market price of its publicly traded units and to increase the cash distribution the Partnership and/or the other affiliated partnerships pay to their respective unitholders.

ET's General Partner grants restricted unit and/or phantom unit awards that vest, based generally upon continued employment, at a rate of 60% after the third year of service and the remaining 40% after the fifth year of service. ET's General Partner believes that these equity-based incentive arrangements are important in attracting and retaining executive officers and key employees as well as motivating these individuals to achieve stated business objectives. The equity-based compensation reflects the importance ET's General Partner places on aligning the interests of its named executive officers with those of unitholders.

As discussed below, the ET Compensation Committee, the ETO Compensation Committee (prior to the Energy Transfer Merger) is responsible for the compensation policies and compensation level of the named executive officers. In this discussion, we refer to ET Compensation Committee and the ETO Compensation Committee prior to the Energy Transfer Merger as the "ET Compensation Committee."

For a more detailed description of the compensation to the Partnership's named executive officers, please see "– Compensation Tables" below.

Compensation Philosophy

ET's compensation programs are structured to achieve the following:

•

reward executives with an industry-competitive total compensation package of base salaries and significant incentive opportunities yielding a total compensation package approaching the top-quartile of the market;

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- 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, 2018, the compensation paid to the named executive officers consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- time-vested restricted/phantom unit awards under the equity incentive plan(s);
- payment of distribution equivalent rights (“DERs”) on unvested time-based restricted unit awards under our equity incentive plan;
- vesting of previously issued time-based restricted unit and/or phantom unit awards issued pursuant to ET’s equity incentive plans or the equity incentive plans(s) of affiliates; and
- 401(k) plan employer contributions.

Methodology

The ET 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 the executive officers of its General Partner, including the named executive officers. The ET Compensation Committee also considers individual performance, levels of responsibility, skills and experience.

Periodically, the ET Compensation Committee engages a third-party consultant to provide a full market competitive compensation analysis for compensation levels at peer companies in order to assist in the determination of compensation levels for our executive officers, including the named executive officers. Most recently, Longnecker & Associates (“Longnecker”) evaluated the market competitiveness of total compensation levels of a number of officers of the Partnership to provide market information with respect to compensation of those executives during the year ended December 31, 2017. In particular, the 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 our senior management, including the named executive officers; and (iii) confirm that our compensation programs were yielding compensation packages consistent with our overall compensation philosophy.

In conducting its review, Longnecker specifically considered the larger size of the combined ET and ETO 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 the profile of ET and ETO 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, the size of ET and ETO on a combined basis was considered. As part of the evaluation 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.