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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

November 12, 2020
Date of Report (Date of earliest event reported)

ENERGY TRANSFER OPERATING, L.P.

(Exact name of Registrant as specified in its charter)

Delaware	**1-31219**	**73-1493906**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

8111 Westchester Drive, Suite 600
Dallas, Texas 75225

(Address of principal executive offices) (zip code)

(214) 981-0700
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETPprC**	**New York Stock Exchange**
7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETPprD**	**New York Stock Exchange**
7.600% Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETPprE**	**New York Stock Exchange**

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

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. ☐

Item 8.01. Other Events.

This Current Report on Form 8-K is being filed principally to reflect retrospective revisions that have been made to the consolidated financial statements and certain related information of Energy Transfer Operating, L.P. ("ETO" or the "Partnership") that were filed with the Securities and Exchange Commission ("SEC") by the Partnership on February 21, 2020 as Items 1, 1A, 6, 7 and 8 to its Annual Report on Form 10-K for the year ended December 31, 2019 (the "2019 Form 10-K").

Energy Transfer LP ("ET") completed the acquisition of SemGroup ("SemGroup") in December 2019. ETO is a consolidated subsidiary of ET. As disclosed in our Quarterly Report on Form 10-Q for the period ended September 30, 2020, filed on November 5, 2020, ET contributed SemGroup and its former subsidiaries to ETO during the first and second quarters of 2020.

In addition, effective January 1, 2020, the Partnership elected to change its accounting policy related to certain barrels of crude oil that were previously accounted for as inventory. Under the previous accounting policy, all crude oil barrels were recorded as inventory under the weighted-average cost method. Under the revised accounting policy, barrels related to pipeline linefill and tank bottoms are accounted for as long-lived assets and reflected as non-current assets on the consolidated balance sheet.

The consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" have been updated to reflect material subsequent events that have occurred after the date the consolidated financial statements were originally issued. As further discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Exhibit 99.1, that item has been updated solely to reflect the changes discussed above. No attempt has been made to modify or update other disclosures in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" (included in Exhibit 99.1) to reflect events or occurrences after the date of the filing of the 2019 Form 10-K, February 21, 2020.

Item 9.01 of this Current Report on Form 8-K revises certain information contained in ETO's 2019 Form 10-K to reflect these retrospective revisions. In particular, Exhibit 99.1 contains revised financial statements and Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 9.01 Financial Statements and Exhibits.

See the Exhibit Index set forth below for a list of exhibits included with this Form 8-K.

Exhibit Number	**Description**
99.1	Revised Energy Transfer Operating, L.P. financial statements as of December 31, 2019 and 2018, and for each of the three years in the period ended December 31, 2019, and Management's Discussion and Analysis of Financial Condition and Results of Operations.
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2019 and December 31, 2018; (ii) our Consolidated Statements of Operations for the years ended December 31, 2019, 2018 and 2017; (iii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2019, 2018 and 2017; (iv) our Consolidated Statement of Partners' Capital for the years ended December 31, 2019, 2018 and 2017; (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017; and (vi) the notes to our Consolidated Financial Statements.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)

SIGNATURE

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

ENERGY TRANSFER OPERATING, L.P.

By: Energy Transfer Partners GP, L.P.,
its general partner

By: Energy Transfer Partners, L.L.C.,
its general partner

Date: November 12, 2020

By: /s/ Thomas E. Long
Thomas E. Long
Chief Financial Officer

TABLE OF CONTENTS

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,” “forecast,” “may,” “will” or similar expressions help identify forward-looking statements. Although the Partnership and its General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership’s actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management’s control. For additional discussion of risks, uncertainties and assumptions, see “Item 1A. Risk Factors” included in this annual report.

Definitions

The following is a list of certain acronyms and terms used 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
Dakota Access	Dakota Access, LLC, a less than wholly-owned subsidiary of ETO
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, the parent company of ETO
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company and is a wholly-owned subsidiary of ETO
ETC Sunoco	ETC Sunoco Holdings LLC (formerly, Sunoco Inc.), a wholly-owned subsidiary of ETO
ETC Tiger	ETC Tiger Pipeline, LLC, a wholly-owned subsidiary of ETO
ETCO	Energy Transfer Crude Oil Company, LLC, a less than wholly-owned subsidiary of ETO
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETO

ETP Holdco	ETP Holdco Corporation, a wholly owned subsidiary of ETO
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, a wholly-owned subsidiary of Citrus
GAAP	accounting principles generally accepted in the United States of America
Gulf States	Gulf States Transmission LLC, a wholly-owned subsidiary of ETO
HFOTCO	Houston Fuel Oil Terminal Company, a wholly-owned subsidiary of ETO, which owns the Houston Terminal
HPC	RIGS Haynesville Partnership Co., a wholly-owned subsidiary of ETO
IDRs	incentive distribution rights
KMI	Kinder Morgan Inc.
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC), a wholly-owned subsidiary of ETO
LCL	Lake Charles LNG Export Company, LLC, a wholly-owned subsidiary of ETO
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Lone Star	Lone Star NGL LLC, a wholly-owned subsidiary of ETO
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
Mi Vida JV	Mi Vida JV LLC
Mid-Valley	Mid-Valley Pipeline Company, a wholly-owned subsidiary of ETO
MMBls	million barrels
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, a less than wholly-owned subsidiary of ETO
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries, wholly-owned by ETO
PCBs	polychlorinated biphenyls
PennTex	PennTex Midstream Partners, LP, acquired by ETO during 2016-2017 and now a wholly-owned subsidiary named ETC PennTex LLC
PEP	Permian Express Partners LLC, a less than wholly-owned subsidiary of ETO

PES	Philadelphia Energy Solutions Refining and Marketing LLC, non-controlling interest owned by ETO
Phillips 66	Phillips 66 Partners LP
PHMSA	Pipeline Hazardous Materials Safety Administration
Preferred Unitholders	Unitholders of the Series A Preferred Units, Series B Preferred Units, Series C Preferred Units, Series D Preferred Units, Series E Preferred Units, Series F Preferred Units and Series G Preferred Units, collectively
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP, a wholly-owned subsidiary of ETO
Retail Holdings	ETP Retail Holdings, LLC, a wholly-owned subsidiary of ETO
RIGS	Regency Intrastate Gas System, a wholly-owned subsidiary of ETO
Rover	Rover Pipeline LLC, a less than wholly-owned subsidiary of ETO
Sea Robin	Sea Robin Pipeline Company, LLC, a wholly-owned subsidiary of Panhandle
SEC	Securities and Exchange Commission
SemCAMS	SemCAMS Midstream ULC, a less than wholly-owned subsidiary of ETO
SemGroup	SemGroup Corporation
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
Series E Preferred Units	7.600% Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series F Preferred Units	6.750% Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series G Preferred Units	7.125% Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Shell	Royal Dutch Shell plc
Southwest Gas	Pan Gas Storage, LLC (d.b.a. Southwest Gas Storage Company)
SPLP	Sunoco Pipeline L.P., a wholly-owned subsidiary of ETO
Sunoco Logistics	Sunoco Logistics Partners L.P., a wholly-owned subsidiary of ETO
Sunoco (R&M)	Sunoco (R&M), LLC
Transwestern	Transwestern Pipeline Company, LLC, a wholly-owned subsidiary of ETO
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC, a wholly-owned subsidiary of Panhandle
Unitholders	Preferred Unitholders and our common unitholder (Energy Transfer LP), collectively
USAC	USA Compression Partners, LP, a wholly-owned subsidiary of ETO

Adjusted EBITDA is a term used throughout this document, which we define as total Partnership 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, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Adjusted EBITDA reflect amounts for unconsolidated affiliates based on the same recognition and measurement methods used to record equity in earnings of unconsolidated affiliates. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA and consolidated Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates. The use of Segment Adjusted EBITDA or Adjusted EBITDA related to unconsolidated affiliates as an analytical tool should be limited accordingly.

PART II

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.

As discussed in Note 2 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" the Partnership's consolidated financial statements for all periods presented have been retrospectively adjusted to reflect the change in the accounting policy related to certain barrels of crude oil.

As discussed in Note 3 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" the sale and contribution transactions resulted in the retrospective adjustment to consolidate SemGroup and its former subsidiaries beginning December 5, 2019. Accordingly, the selected financial data below reflects the consolidated financial information of legacy ETO, adjusted for the effects of the events above.

	Years Ended December 31,				
	2019	2018	2017	2016	2015
Statement of Operations Data:					
Total revenues	$ 54,213	$ 54,087	$ 40,523	$ 31,792	$ 36,096
Operating income	7,222	5,457	2,714	1,933	2,410
Income from continuing operations	5,115	4,094	2,901	869	1,440
Balance Sheet Data (at period end):					
Assets held for sale	—	—	3,313	3,588	3,681
Total assets	102,294	88,609	86,596	79,147	71,322
Liabilities associated with assets held for sale	—	—	75	48	42
Long-term debt, less current maturities	50,904	37,853	36,971	36,251	30,505
Total equity	37,425	36,788	37,079	29,101	30,173
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis) (1)	658	510	479	474	550
Growth (accrual basis) (1)	4,610	5,120	5,601	5,775	8,046
Cash paid for acquisitions	257	429	583	1,398	964

(1) Maintenance and growth capital expenditures include Sunoco LP's capital expenditures related to discontinued operations for the years ended December 31, 2016 and 2015.

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)

In order to preserve the nature and character of the disclosures set forth in the 2019 Form 10-K, the items included in this "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" have been updated solely to reflect ETO's change in its accounting policy related to certain barrels of crude oil and the retrospective consolidation of SemGroup, as further discussed below and in "Item 8. Financial Statements and Supplementary Data" included elsewhere in this Exhibit 99.1. No attempt has been made to modify or update other disclosures in this "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" to reflect events or occurrences after the date of the filing of the 2019 Form 10-K, February 21, 2020. Therefore, this "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" should be read in conjunction with the 2019 Form 10-K, and filings made by ETO with the SEC subsequent to the filing of the 2019 Form 10-K, including ETO's Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2020, June 30, 2020 and September 30, 2020 filed on May 11, 2020, August 6, 2020 and November 5, 2020.

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

Series F and Series G Preferred Units Issuance

On January 22, 2020, ETO issued 500,000 of its 6.750% Series F Preferred Units at a price of $1,000 per unit and 1,100,000 of its 7.125% Series G Preferred Units at a price of $1,000 per unit. The net proceeds were used to repay amounts outstanding under ETO's revolving credit facility and for general partnership purposes.

ETO January 2020 Senior Notes Offering and Redemption

On January 22, 2020, ETO completed a registered offering (the "January 2020 Senior Notes Offering") of $1.00 billion aggregate principal amount of the Partnership's 2.900% Senior Notes due 2025, $1.50 billion aggregate principal amount of the Partnership's 3.750% Senior Notes due 2030 and $2.00 billion aggregate principal amount of the Partnership's 5.000% Senior Notes due 2050, (collectively, the "Notes"). The Notes are fully and unconditionally guaranteed by the Partnership's wholly owned subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis.

Utilizing proceeds from the January 2020 Senior Notes Offering, ETO redeemed its $400 million aggregate principal amount of 5.75% Senior Notes due September 1, 2020, its $1.05 billion aggregate principal amount of 4.15% Senior Notes due October 1, 2020, its $1.14 billion aggregate principal amount of 7.50% Senior Notes due October 15, 2020, its $250 million aggregate principal amount of 5.50% Senior Notes due February 15, 2020, ET's $52 million aggregate principal amount of 7.50% Senior Notes due October 15, 2020 and Transwestern's $175 million aggregate principal amount of 5.36% Senior Notes due December 9, 2020.

ETO Term Loan

On October 17, 2019, ETO entered into a term loan credit agreement (the “ETO Term Loan”) providing for a $2.00 billion three-year term loan credit facility. Borrowings under the term loan agreement mature on October 17, 2022 and are available for working capital purposes and for general partnership purposes. The term loan agreement is unsecured and is guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P.

As of December 31, 2019, the ETO Term Loan had $2.00 billion outstanding and was fully drawn. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.78%.

SemGroup Acquisition

In December 2019, ET completed the acquisition of SemGroup. ET contributed SemGroup and its former subsidiaries to ETO through sale and contribution transactions in 2020. The contribution transactions were accounted for as reorganizations of entities under common control; therefore, the contributed entities’ assets and liabilities were not adjusted as of the contribution date.

JC Nolan Pipeline

On July 1, 2019, ETO and Sunoco LP entered into a joint venture on the JC Nolan diesel fuel pipeline to West Texas and the JC Nolan terminal. ETO operates the pipeline for the joint venture, which transports diesel fuel from Hebert, Texas to a terminal in the Midland, Texas area. The diesel fuel pipeline has an initial capacity of 30,000 barrels per day and was successfully commissioned in August 2019.

Series E Preferred Units Issuance

In April 2019, ETO issued 32 million of its 7.600% Series E Preferred Units at a price of $25 per unit, including 4 million Series E Preferred Units pursuant to the underwriters’ exercise of their option to purchase additional preferred units. The total gross proceeds from the Series E Preferred Unit issuance were $800 million, including $100 million from the underwriters’ exercise of their option to purchase additional preferred units. The net proceeds were used to repay amounts outstanding under ETO’s revolving credit facility and for general partnership purposes.

ET-ETO Senior Notes Exchange

In March 2019, ETO issued approximately $4.21 billion aggregate principal amount of senior notes to settle and exchange approximately 97% of ET’s outstanding senior notes. In connection with this exchange, ETO issued $1.14 billion aggregate principal amount of 7.50% senior notes due 2020, $995 million aggregate principal amount of 4.25% senior notes due 2023, $1.13 billion aggregate principal amount of 5.875% senior notes due 2024 and $956 million aggregate principal amount of 5.50% senior notes due 2027.

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.

Panhandle Senior Notes Redemption

In June 2019, Panhandle’s $150 million aggregate principal amount of 8.125% senior notes matured and were repaid with borrowings under an affiliate loan agreement with ETO.

Bakken Senior Notes Offering

In March 2019, Midwest Connector Capital Company LLC, a wholly-owned subsidiary of Dakota Access, issued $650 million aggregate principal amount of 3.625% senior notes due 2022, $1.00 billion aggregate principal amount of 3.90% senior notes due 2024 and $850 million aggregate principal amount of 4.625% senior notes due 2029. The $2.48 billion in net proceeds from the offering were used to repay in full all amounts outstanding on the Bakken credit facility and the facility was terminated.

Sunoco LP Senior Notes Offering

In March 2019, Sunoco LP issued $600 million aggregate principal amount of 6.00% senior notes due 2027 in a private placement to eligible purchasers. The net proceeds from this offering were used to repay a portion of Sunoco LP's existing borrowings under its credit facility. In July 2019, Sunoco LP completed an exchange of these notes for registered notes with substantially identical terms.

USAC Senior Notes Offering

In March 2019, USAC issued $750 million aggregate principal amount of 6.875% senior notes due 2027 in a private placement, and in December 2019, USAC exchanged those notes for substantially identical senior notes registered under the Securities Act. The net proceeds from this offering were used to repay a portion of USAC's existing borrowings under its credit facility and for general partnership purposes.

Regulatory Update

Interstate Natural Gas Transportation Regulation

Rate 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. 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") on March 15, 2018, 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.

In March 2019, following the decision of the D.C. Circuit in Emera Maine v. Federal Energy Regulatory Commission, the FERC issued a Notice of Inquiry regarding its policy for determining return on equity ("ROE"). The FERC specifically sought information and stakeholder views to help the FERC explore whether, and if so how, it should modify its policies concerning the determination of ROE to be used in designing jurisdictional rates charged by public utilities. The FERC also expressly sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. Initial comments were due in June 2019, and reply comments were due in July 2019. The FERC has not taken any further action with respect to the Notice of Inquiry as of this time, and therefore we cannot predict what effect, if any, such development could have on our cost-of-service rates in the future.

Also 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 to address changes to the pipeline's revenue requirements as a result of the tax reductions: file a limited Natural Gas Act ("NGA") Section 4 filing reducing its rates to reflect the reduced tax rates, 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 filed a cost and revenue study on April 1, 2019. Panhandle filed a NGA Section 4 rate case on August 30, 2019.

By order issued October 1, 2019, the Panhandle Section 5 and Section 4 cases were consolidated. An initial decision is expected to be issued in the first quarter of 2021. By order issued February 19, 2019, the FERC initiated a review of Southwest Gas' existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Southwest Gas are just and reasonable and set the matter for hearing. Southwest Gas filed a cost and revenue study on May 6, 2019. On July 10, 2019, Southwest filed an Offer of Settlement in this Section 5 proceeding, which settlement was supported or not opposed by Commission Trial Staff and all active parties. The settlement was approved on October 29, 2019.

Sea Robin Pipeline Company filed a Section 4 rate case on November 30, 2018. A procedural schedule was ordered with a hearing date in the 4th quarter of 2019. Sea Robin Pipeline Company has reached a settlement of this proceeding, with a settlement filed July 22, 2019. The settlement was approved by the FERC by order dated October 17, 2019.

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.

Pipeline Certification

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 Common Carrier 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.

Trends and Outlook

We anticipate continued earnings growth in 2020 from the recently completed projects, as well as our current 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 in recent months as associated gas from shale oil resources has provided additional supply to the market, increasing domestic supply to highs above 100 Bcf/d. Global oil and natural gas demand growth is likely to continue into the foreseeable future and will support U.S. production increases and, in turn U.S. natural gas export projects to Mexico as well as LNG exports.

For crude oil, new pipelines that came online during 2019 have resulted in Permian barrels now pricing closer to other regional hubs, which is a departure from the substantial discounts seen a year ago. These pipelines have enabled Permian producers to realize higher crude oil revenues, supporting continued growth in the region. Crude oil exports from the U.S. are continuing to increase as a result, providing additional opportunity for U.S. midstream sector growth.

Results of Operations

We report Segment Adjusted EBITDA and consolidated Adjusted EBITDA as measures of segment performance. We define Segment Adjusted EBITDA and consolidated Adjusted EBITDA as total Partnership 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, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Segment Adjusted EBITDA and consolidated Adjusted EBITDA reflect amounts for unconsolidated affiliates based on the same recognition and measurement methods used to record equity in earnings of unconsolidated affiliates. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA and consolidated Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates. The use of Segment Adjusted EBITDA or Adjusted EBITDA related to unconsolidated affiliates as an analytical tool should be limited accordingly.

Segment Adjusted EBITDA, as reported for each segment in the table below, is analyzed for each segment in the section titled “Segment Operating Results.” Adjusted EBITDA is a non-GAAP measure used by industry analysts, investors, lenders and rating agencies to assess the financial performance and the operating results of the Partnership’s fundamental business activities and should not be considered in isolation or as a substitution for net income, income from operations, cash flows from operating activities or other GAAP measures.

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, 2017 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.

As discussed in Note 2 to the consolidated financial statements in “Item 8. Financial Statements and Supplementary Data” the Partnership’s consolidated financial statements for all periods presented have been retrospectively adjusted to reflect the change in the accounting policy related to certain barrels of crude oil.

As discussed in Note 3 to the consolidated financial statements in “Item 8. Financial Statements and Supplementary Data” the sale and contribution transactions resulted in the retrospective adjustment to consolidate SemGroup and its former subsidiaries beginning December 5, 2019. Accordingly, the financial data below reflects the consolidated financial information of legacy ETO.

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Consolidated Results

	Years Ended December 31, 2019	Years Ended December 31, 2018	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 999	$ 927	$ 72
Interstate transportation and storage	1,792	1,680	112
Midstream	1,602	1,627	(25)
NGL and refined products transportation and services	2,666	1,979	687
Crude oil transportation and services	2,898	2,385	513
Investment in Sunoco LP	665	638	27
Investment in USAC	420	289	131
All other	106	76	30
Total Segment Adjusted EBITDA	11,148	9,601	1,547
Depreciation, depletion and amortization	(3,136)	(2,843)	(293)
Interest expense, net of interest capitalized	(2,262)	(1,709)	(553)
Impairment losses	(74)	(431)	357
Gains (losses) on interest rate derivatives	(241)	47	(288)
Non-cash compensation expense	(113)	(105)	(8)
Unrealized losses on commodity risk management activities	(5)	(11)	6
Inventory valuation adjustments	79	(85)	164
Losses on extinguishments of debt	(2)	(109)	107
Adjusted EBITDA related to unconsolidated affiliates	(626)	(655)	29
Equity in earnings of unconsolidated affiliates	302	344	(42)
Adjusted EBITDA related to discontinued operations	—	25	(25)
Other, net	244	30	214
Income from continuing operations before income tax expense	5,314	4,099	1,215
Income tax expense from continuing operations	(199)	(5)	(194)
Income from continuing operations	5,115	4,094	1,021
Loss from discontinued operations, net of income taxes	—	(265)	265
Net income	$ 5,115	$ 3,829	$ 1,286

Adjusted EBITDA (*consolidated*). For the year ended December 31, 2019 compared to the prior year, Adjusted EBITDA increased approximately $1.55 billion, or 16%. The increase was primarily due to the impact of multiple revenue-generating assets being placed in service and recent acquisitions, as well as increased demand for services on existing assets. The impact of new assets and acquisitions was approximately $784 million, of which the largest increases were from increased volumes to our Mariner East pipeline and terminal assets due to the addition of pipeline capacity in the fourth quarter of 2018 (a $274 million impact to the NGL and refined products transportation and services segment), the commissioning of our fifth and sixth fractionators (a $131 million impact to the NGL and refined products transportation and services segment), the ramp up of volumes on our Bayou Bridge system due to placing phase II in service in the second quarter of 2019 (a $60 million impact to our crude oil transportation and services segment), the Rover pipeline (a $78 million impact to the interstate transportation and storage segment), the addition of gas processing capacity to our Arrowhead gas plant (a $31 million impact to our midstream segment), placing our Permian Express 4 pipeline in service in October 2019 (a $26 million impact to our crude oil transportation and services segment) and the acquisition of USAC (a net impact of $131 million among the investment in USAC and all other segments). The remainder of the increase in Adjusted EBITDA was primarily due to stronger demand on existing assets, particularly due to increased throughput on our Bakken Pipeline system as well as increased production in the Permian, which impacted multiple segments. Additional discussion of these and other factors affecting Adjusted EBITDA is included in the analysis of Segment Adjusted EBITDA in the “Segment Operating Results” section 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 of Interest Capitalized. Interest expense, net of interest capitalized, increased during the year ended December 31, 2019 compared to the prior year primarily due to the following:

- an increase of $475 million recognized by the Partnership (excluding Sunoco LP and USAC) primarily related to an increase in long-term debt, which included $4.2 billion of senior notes issued in the ET-ETO senior note exchange (discussed below under “Description of Indebtedness”), as well as additional senior note issuances and borrowings under our revolving credit facilities;
- an increase of $49 million recognized by USAC primarily attributable to higher overall debt balances and higher interest rates on borrowings under the credit agreement. These increases were partially offset by the decrease in borrowings under the credit agreement; and
- an increase of $29 million recognized by Sunoco LP due to an increase in total long-term debt.

Impairment Losses. During the year ended December 31, 2019, the Partnership recognized goodwill impairments of $12 million related to the Southwest Gas operations within the interstate transportation and storage segment and $9 million related to our North Central operations within the midstream segment, both of which were primarily due to changes in assumptions related to projected future revenues and cash flows. Also during the year ended December 31, 2019, Sunoco LP recognized a $47 million write-down on assets held for sale related to its ethanol plant in Fulton, New York, and USAC recognized a $6 million fixed asset impairment related to certain idle compressor assets.

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 idle leased assets in our crude operations. Sunoco LP recognized a $30 million indefinite-lived intangible asset impairment related to contractual rights. USAC recognized a $9 million fixed asset impairment related to certain idle compressor assets. 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. Losses on interest rate derivatives during the year ended December 31, 2019 resulted from a decrease in forward interest rates and gains in 2018 resulted from an increase in forward interest rates.

Unrealized Losses on Commodity Risk Management Activities. The unrealized losses on our commodity risk management activities include changes in fair value of commodity derivatives and the hedged inventory included in designated fair value hedging relationships. Information on the unrealized gains and losses within each segment are included in “Segment Operating Results” below, and additional information on the commodity-related derivatives, including notional volumes, maturities and fair values, is available in “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” and in Note 13 to our consolidated financial statements included in “Item 8. Financial Statements and Supplementary Data.”

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco LP primarily driven by 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.

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. For the year ended December 31, 2019 compared to the prior year, income tax expense increased due to an increase in income at our corporate subsidiaries and the recognition of a favorable state tax rate change in the prior period.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2019	Years Ended December 31, 2018	Change
Equity in earnings of unconsolidated affiliates:			
Citrus	$ 148	$ 141	$ 7
FEP	59	55	4
MEP	15	31	(16)
Other	80	117	(37)
Total equity in earnings of unconsolidated affiliates	$ 302	$ 344	$ (42)
Adjusted EBITDA related to unconsolidated affiliates[1]:			
Citrus	$ 342	$ 337	$ 5
FEP	75	74	1
MEP	60	81	(21)
Other	149	163	(14)
Total Adjusted EBITDA related to unconsolidated affiliates	$ 626	$ 655	$ (29)
Distributions received from unconsolidated affiliates:			
Citrus	$ 178	$ 171	$ 7
FEP	73	68	5
MEP	36	48	(12)
Other	101	110	(9)
Total distributions received from unconsolidated affiliates	$ 388	$ 397	$ (9)

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

Segment Operating Results

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

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

- *Segment margin, operating expenses*, and *selling, general and administrative expenses*. These amounts represent the amounts included in our consolidated financial statements that are attributable to each segment.
- *Unrealized gains or losses on commodity risk management activities* and *inventory valuation adjustments*. These are the unrealized amounts that are included in cost of products sold to calculate segment margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.
- *Non-cash compensation expense*. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative expenses. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.

- *Adjusted EBITDA related to unconsolidated affiliates*. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates.

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. Among the GAAP measures reported by the Partnership, the most directly comparable measure to segment margin is Segment Adjusted EBITDA; a reconciliation of segment margin to Segment Adjusted EBITDA is included in the following tables for each segment where segment margin is presented.

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

Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2019	2018	Change
Natural gas transported (BBtu/d)	12,442	10,873	1,569
Revenues	$ 3,099	$ 3,737	$ (638)
Cost of products sold	1,909	2,665	(756)
Segment margin	1,190	1,072	118
Unrealized losses on commodity risk management activities	2	38	(36)
Operating expenses, excluding non-cash compensation expense	(190)	(189)	(1)
Selling, general and administrative expenses, excluding non-cash compensation expense	(29)	(27)	(2)
Adjusted EBITDA related to unconsolidated affiliates	25	32	(7)
Other	1	1	—
Segment Adjusted EBITDA	$ 999	$ 927	$ 72

Volumes. For the year ended December 31, 2019 compared to the prior year, transported volumes increased primarily due to the impact of reflecting RIGS as a consolidated subsidiary beginning April 2018 and the impact of the Red Bluff Express pipeline coming online in May 2018, as well as the impact of favorable market pricing spreads.

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

	Years Ended December 31, 2019	Years Ended December 31, 2018	Change
Transportation fees	$ 614	$ 525	$ 89
Natural gas sales and other (excluding unrealized gains and losses)	505	510	(5)
Retained fuel revenues (excluding unrealized gains and losses)	50	59	(9)
Storage margin, including fees (excluding unrealized gains and losses)	23	16	7
Unrealized losses on commodity risk management activities	(2)	(38)	36
Total segment margin	$ 1,190	$ 1,072	$ 118

Segment Adjusted EBITDA. For the year ended December 31, 2019 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 $64 million in transportation fees, excluding the impact of consolidating RIGS beginning April 2018 as discussed below, primarily due to the Red Bluff Express pipeline coming online in May 2018, as well as new contracts;
- a net increase of $11 million primarily due to the consolidation of RIGS beginning April 2018, resulting in increases in transportation fees, retained fuel revenues and operating expenses of $24 million, $2 million and $6 million, respectively, partially offset by a decrease in Adjusted EBITDA related to unconsolidated affiliates of $9 million; and
- an increase of $7 million in realized storage margin primarily due to a realized adjustment to the Bammel storage inventory of $25 million in 2018 and higher storage fees, partially offset by a $20 million decrease due to lower physical withdrawals; partially offset by
- a decrease of $9 million in retained fuel revenues primarily due to lower gas prices; and
- a decrease of $5 million in realized natural gas sales and other due to lower realized gains from pipeline optimization activity.

Interstate Transportation and Storage

	Years Ended December 31, 2019	Years Ended December 31, 2018	Change
Natural gas transported (BBtu/d)	11,346	9,542	1,804
Natural gas sold (BBtu/d)	17	17	—
Revenues	$ 1,963	$ 1,682	$ 281
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(569)	(431)	(138)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(72)	(63)	(9)
Adjusted EBITDA related to unconsolidated affiliates	477	492	(15)
Other	(7)	—	(7)
Segment Adjusted EBITDA	$ 1,792	$ 1,680	$ 112

Volumes. For the year ended December 31, 2019 compared to the prior year, transported volumes increased as a result of the addition of new contracted volumes for delivery out of the Haynesville Shale, higher volumes on our Rover pipeline as a result of the full year availability of new supply connections, and higher throughput on Trunkline and Panhandle due to increased utilization of higher contracted capacity.

Segment Adjusted EBITDA. For the year ended December 31, 2019 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 in margin of $231 million from the Rover pipeline due to higher reservation and usage resulting from additional connections and utilization of additional compression;

- an increase of $40 million in reservation and usage fees due to improved market conditions allowing us to successfully bring new volumes to the system at improved rates, primarily on our Transwestern, Tiger and Panhandle Eastern systems; and
- an increase of $6 million from the Sea Robin pipeline due to higher rates resulting from the rate case filed in June 2019, as well as fewer third party supply interruptions on the Sea Robin system; partially offset by
- an increase of $138 million in operating expense primarily due to an increase in ad valorem taxes of $126 million on the Rover pipeline system resulting from placing the final portions of this asset into service in November 2018, an increase of $24 million in transportation expense on Rover due to an increase in transportation volumes, an increase of $5 million in allocated overhead costs and additional operating expense of $4 million for assets acquired in June 2019, partially offset by lower gas imbalance and system gas activity of $15 million and lower storage capacity leased on the Panhandle Eastern system of $8 million;
- an increase of $9 million in selling, general and administrative expenses primarily due to an increase in insurance expense of $8 million, an increase in employee cost of $4 million, and an increase in allocated overhead costs of $3 million, partially offset by lower Ohio excise tax on our Rover system; and
- a decrease of $15 million in adjusted EBITDA related to unconsolidated affiliates primarily resulting from a $20 million decrease due to lower earnings from MEP as a result of lower capacity being re-contracted at lower rates on expiring contracts, partially offset by a $5 million increase from our Citrus joint venture as we brought new volumes to the system in 2019.

Midstream

	Years Ended December 31,		
	2019	2018	Change
Gathered volumes (BBtu/d)	13,460	12,126	1,334
NGLs produced (MBbls/d)	571	540	31
Equity NGLs (MBbls/d)	31	29	2
Revenues	$ 6,031	$ 7,522	$ (1,491)
Cost of products sold	3,577	5,145	(1,568)
Segment margin	2,454	2,377	77
Operating expenses, excluding non-cash compensation expense	(791)	(705)	(86)
Selling, general and administrative expenses, excluding non-cash compensation expense	(90)	(81)	(9)
Adjusted EBITDA related to unconsolidated affiliates	27	33	(6)
Other	2	3	(1)
Segment Adjusted EBITDA	$ 1,602	$ 1,627	$ (25)

Volumes. For the year ended December 31, 2019 compared to the prior year, gathered volumes increased primarily due to increases in the Northeast, Permian, Ark-La-Tex, South Texas and North Texas regions. NGL production increased due to increases in the Permian and North Texas regions partially offset by ethane rejection in the South Texas region.

Segment Margin. The table below presents the components of our midstream segment margin. For the year ended December 31, 2018, the amounts previously reported for fee-based and non-fee-based margin have been adjusted to reflect reclassification of certain contractual minimum fees from fee-based margin to non-fee-based margin in order to conform to the current period classification.

	Years Ended December 31,		
	2019	2018	Change
Gathering and processing fee-based revenues	$ 2,002	$ 1,788	$ 214
Non-fee based contracts and processing	452	589	(137)
Total segment margin	$ 2,454	$ 2,377	$ 77

Segment Adjusted EBITDA. For the year ended December 31, 2019 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net impacts of the following:

- a decrease of $137 million in non fee-based margin due to lower NGL prices of $131 million and lower gas prices of $58 million, offset by an increase of $51 million in non fee-based margin due to increased throughput volume in North Texas, South Texas and Permian regions;
- an increase of $86 million in operating expenses due to increases of $33 million in outside services, $29 million in maintenance project costs, $17 million in employee costs and $6 million in office expenses and materials; and
- an increase of $9 million in selling, general and administrative expenses primarily due to a decrease of $5 million in capitalized overhead and an increase of $4 million in insurance expense; partially offset by
- an increase of $214 million in fee-based margin due to volume growth in the Northeast, Permian, Ark-La-Tex, North Texas and South Texas regions.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2019	2018	Change
NGL transportation volumes (MBbls/d)	1,289	1,027	262
Refined products transportation volumes (MBbls/d)	583	621	(38)
NGL and refined products terminal volumes (MBbls/d)	944	812	132
NGL fractionation volumes (MBbls/d)	706	527	179
Revenues	$ 11,641	$ 11,123	$ 518
Cost of products sold	8,393	8,462	(69)
Segment margin	3,248	2,661	587
Unrealized (gains) losses on commodity risk management activities	81	(86)	167
Operating expenses, excluding non-cash compensation expense	(656)	(604)	(52)
Selling, general and administrative expenses, excluding non-cash compensation expense	(93)	(74)	(19)
Adjusted EBITDA related to unconsolidated affiliates	86	82	4
Segment Adjusted EBITDA	$ 2,666	$ 1,979	$ 687

Volumes. For the year ended December 31, 2019 compared to the prior year, throughput barrels on our Texas NGL pipeline system increased due to higher receipt of liquids production from both wholly-owned and third-party gas plants primarily in the Permian and North Texas regions. In addition, NGL transportation volumes on our Northeast assets increased due to the initiation of service on the Mariner East 2 pipeline system.

Refined products transportation volumes decreased for the year ended December 31, 2019 compared to prior year due to the closure of a third party refinery during the third quarter of 2019, negatively impacting supply to our refined products transportation system. These decreases in volumes are partially offset by the initiation of service on the JC Nolan Pipeline in the third quarter of 2019.

NGL and refined products terminal volumes increased for the year ended December 31, 2019 compared to the prior year primarily due to the initiation of service on our Mariner East 2 pipeline system which commenced operations in the fourth quarter of 2018.

Average volumes fractionated at our Mont Belvieu, Texas fractionation facility increased for the year ended December 31, 2019 compared to the prior year primarily due to the commissioning of our fifth and sixth fractionators in July 2018 and February 2019, respectively.

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

	Years Ended December 31,		
	2019	2018	Change
Fractionators and refinery services margin	$ 664	$ 511	$ 153
Transportation margin	1,716	1,233	483
Storage margin	223	211	12
Terminal Services margin	630	494	136
Marketing margin	96	126	(30)
Unrealized gains (losses) on commodity risk management activities	(81)	86	(167)
Total segment margin	$ 3,248	$ 2,661	$ 587

Segment Adjusted EBITDA. For the year ended December 31, 2019 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 $483 million in transportation margin primarily due to a $265 million increase resulting from the initiation of service on our Mariner East 2 pipeline in the fourth quarter of 2018, a $212 million increase resulting from higher throughput volumes received from the Permian region on our Texas NGL pipelines, a $29 million increase due to higher throughput volumes from the Barnett region, a $9 million increase from the Eagle Ford region, and a $9 million increase due to the initiation of service on the JC Nolan Pipeline. These increases were partially offset by a $21 million decrease resulting from Mariner East 1 pipeline downtime, a $13 million decrease due to the closure of a third-party refinery during the third quarter of 2019, negatively impacting refined product supply to our system, and a $5 million decrease due to the timing of deficiency fees on Mariner West;
- an increase of $153 million in fractionation and refinery services margin primarily due to a $167 million increase resulting from the commissioning of our fifth and sixth fractionators in July 2018 and February 2019, respectively, and higher NGL volumes from the Permian region feeding our Mont Belvieu fractionation facility. This increase was partially offset by a reclassification between our fractionation and storage margins;
- an increase of $136 million in terminal services margin primarily due to a $171 million increase from the initiation of service of our Mariner East 2 pipeline which commenced operations in the fourth quarter of 2018 and a $7 million increase due to increased tank lease revenue from third-party customers. These increases were partially offset by a $16 million decrease in volumes and expense reimbursements from third parties on Mariner East 1, a $16 million decrease due to lower volumes from third party pipeline, truck and rail deliveries into our Marcus Hook terminal, a $5 million decrease due to fewer vessels exported out of our Nederland terminal, and a $4 million decrease due to the closure of a third party refinery during the third quarter of 2019; and
- an increase of $12 million in storage margin primarily due to a reclassification between our storage and fractionation margins; partially offset by
- a decrease of $30 million in marketing margin primarily due to capacity lease fees incurred by our marketing affiliate on our Mariner East 2 pipeline, offset by increased gains from our butane blending business due to more favorable market conditions and increased volumes, as well as increased optimization gains from the sale of NGL component products at our Mont Belvieu facility;
- an increase of $52 million in operating expenses primarily due to a $26 million increase in employee and ad valorem tax expenses on our terminals, fractionation, and transportation operations, a $14 million increase in utility costs to operate our pipelines and our fifth and sixth fractionators which commenced July 2018 and February 2019, respectively, and an $8 million increase in maintenance project costs due to the timing of multiple projects on our transportation assets; and
- an increase of $19 million in general and administrative expenses primarily due to a $10 million increase in allocated overhead costs, a $5 million increase in insurance expenses, a $4 million increase in legal fees, and a $2 million increase in employee costs.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2019	2018	Change
Crude transportation volumes (MBbls/d)	4,662	4,172	490
Crude terminals volumes (MBbls/d)	2,068	2,096	(28)
Revenue	$ 18,447	$ 17,332	$ 1,115
Cost of products sold	14,832	14,384	448
Segment margin	3,615	2,948	667
Unrealized (gains) losses on commodity risk management activities	(69)	55	(124)
Operating expenses, excluding non-cash compensation expense	(570)	(547)	(23)
Selling, general and administrative expenses, excluding non-cash compensation expense	(85)	(86)	1
Adjusted EBITDA related to unconsolidated affiliates	8	15	(7)
Other	(1)	—	(1)
Segment Adjusted EBITDA	$ 2,898	$ 2,385	$ 513

Segment Adjusted EBITDA. For the year ended December 31, 2019 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 $543 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $282 million increase resulting from higher throughput on our Texas crude pipeline system primarily due to increased production from the Permian region and contributions from capacity expansion projects placed into service, a $219 million increase in throughput on our Bakken pipeline, a favorable change due to inventory valuation adjustment of $75 million, partially offset by a $90 million reduction due to lower pipeline basis spreads net of hedges. We also realized a $66 million increase from higher volumes on our Bayou Bridge Pipeline, a $31 million increase due to the inclusion of assets acquired in 2019, and a $26 million increase primarily from higher throughput, ship loading and tank rental fees at our Nederland terminal; partially offset by a $54 million decrease from our Oklahoma assets resulting from lower volumes to the system as well as from the timing of a deficiency payment made in the prior year, a $12 million decrease due to the closure of a third party refinery which was the primary customer utilizing one of our northeast crude terminals. The remainder of the offsetting decrease was primarily attributable to a change in the presentation of certain intrasegment transactions, which were eliminated in the current period presentation but were shown on a gross basis in revenues and operating expenses in the prior period; partially offset by

- an increase of $23 million in operating expenses primarily due to a $30 million increase in throughput-related costs on existing assets, partially offset by a $14 million decrease in management fees as well as the impact of certain intrasegment transactions discussed above; and

- a decrease of $7 million in Adjusted EBITDA related to unconsolidated affiliates due to lower margin from jet fuel sales by our joint ventures.

Investment in Sunoco LP

	Years Ended December 31, 2019	Years Ended December 31, 2018	Change
Revenues	$ 16,596	$ 16,994	$ (398)
Cost of products sold	15,380	15,872	(492)
Segment margin	1,216	1,122	94
Unrealized (gains) losses on commodity risk management activities	(5)	6	(11)
Operating expenses, excluding non-cash compensation expense	(365)	(435)	70
Selling, general and administrative, excluding non-cash compensation expense	(123)	(129)	6
Adjusted EBITDA related to unconsolidated affiliates	4	—	4
Inventory valuation adjustments	(79)	85	(164)
Adjusted EBITDA from discontinued operations	—	(25)	25
Other, net	17	14	3
Segment Adjusted EBITDA	$ 665	$ 638	$ 27

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

Segment Adjusted EBITDA. For the year ended December 31, 2019 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:

- a decrease in operating costs of $76 million, primarily as a result of the conversion of 207 retail sites to commission agent sites during April 2018. These expenses include other operating expense, general and administrative expense and lease expense; and
- an increase of $25 million related to Adjusted EBITDA from discontinued operations related to the divestment of 1,030 company-operated fuel sites to 7-Eleven in January 2018; and
- an increase of $4 million in Adjusted EBITDA related to unconsolidated affiliates due to Sunoco LP’s investment in the JC Nolan joint venture; partially offset by
- a decrease in the gross profit on motor fuel sales of $76 million (excluding the change in inventory fair value adjustments and unrealized gains and losses on commodity risk management activities) primarily due to lower fuel margins, a one-time benefit of approximately $25 million related to a cash settlement with a fuel supplier recorded in 2018 and an $8 million one-time charge related to a reserve for an open contractual dispute recorded in 2019, partially offset by an increase in gallons sold.

Investment in USAC

	Years Ended December 31, 2019	Years Ended December 31, 2018	Change
Revenues	$ 698	$ 508	$ 190
Cost of products sold	91	67	24
Segment margin	607	441	166
Operating expenses, excluding non-cash compensation expense	(134)	(110)	(24)
Selling, general and administrative, excluding non-cash compensation expense	(53)	(50)	(3)
Other, net	—	8	(8)
Segment Adjusted EBITDA	$ 420	$ 289	$ 131

The investment in USAC segment reflects the consolidated results of USAC from April 2, 2018, the date ET obtained control of USAC. Changes between periods are primarily due to the consolidation of USAC beginning April 2, 2018.

All Other

	Years Ended December 31,		
	2019	2018	Change
Revenue	$ 1,689	$ 2,228	$ (539)
Cost of products sold	1,504	2,006	(502)
Segment margin	185	222	(37)
Unrealized gains on commodity risk management activities	(4)	(2)	(2)
Operating expenses, excluding non-cash compensation expense	(77)	(56)	(21)
Selling, general and administrative expenses, excluding non-cash compensation expense	(58)	(87)	29
Adjusted EBITDA related to unconsolidated affiliates	2	1	1
Other and eliminations	58	(2)	60
Segment Adjusted EBITDA	$ 106	$ 76	$ 30

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 7.4% interest in PES and no longer reflects PES as an affiliate; and
- our investment in coal handling facilities;
- our Canadian operations, which were acquired in the SemGroup acquisition in December 2019 and include natural gas gathering and processing assets.

Segment Adjusted EBITDA. For the year ended December 31, 2019 compared to the prior year, Segment Adjusted EBITDA increased due to the net impacts of the following:

- an increase of $8 million in gains from park and loan and storage activity;
- an increase of $11 million in optimized gains on residue gas sales;
- an increase of $7 million from settled derivatives;
- an increase of $15 million from a legal settlement;
- an increase of $12 million from payments related to the PES bankruptcy;
- an increase of $6 million from the recognition of deferred revenue related to a bankruptcy;
- an increase of $3 million from power trading activities;
- an increase of $3 million from the SemCAMS joint venture for the period subsequent to our acquisition of SemGroup on December 5, 2019, net of an increase due to SemGroup related corporate expenses; and
- a decrease of $21 million in merger and acquisition expenses; partially offset by
- a decrease of $36 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 $8 million due to lower gas prices and increased power costs; and
- a decrease of $11 million due to lower revenue from our compressor equipment business.

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

Consolidated Results

	Years Ended December 31, 2018	Years Ended December 31, 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	2,385	1,328	1,057
Investment in Sunoco LP	638	732	(94)
Investment in USAC	289	—	289
All other	76	219	(143)
Total	9,601	7,301	2,300
Depreciation, depletion and amortization	(2,843)	(2,541)	(302)
Interest expense, net of interest capitalized	(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	4,099	1,097	3,002
Income tax (expense) benefit from continuing operations	(5)	1,804	(1,809)
Income from continuing operations	4,094	2,901	1,193
Loss from discontinued operations, net of income taxes	(265)	(177)	(88)
Net income	$ 3,829	$ 2,724	$ 1,105

Adjusted EBITDA (*consolidated*). For the year ended December 31, 2018 compared to the prior year, Adjusted EBITDA increased approximately $2.3 billion, or 32%. The increase was primarily due to the impact of multiple revenue-generating assets being placed in service and recent acquisitions, as well as increased demand for services on existing assets. The impact of new assets and acquisitions was approximately $1.2 billion, of which the largest increases were from the Bakken pipeline (a $546 million impact to the crude oil transportation and services segment), the Rover pipeline (a $359 million impact to the interstate transportation and storage segment) and the acquisition of USAC (a net impact of $191 million among the investment in USAC and all other segments). The remainder of the increase in Adjusted EBITDA was primarily due to stronger demand on existing assets, particularly due to increased production in the Permian, which impacted multiple segments. Additional discussion of these and other factors affecting Adjusted EBITDA is included in the analysis of Segment Adjusted EBITDA in the “Segment Operating Results” section 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 of Interest Capitalized. Interest expense, net of interest capitalized, increased during the year ended December 31, 2018 compared 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.

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 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 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 in 2018 and 2017 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 2018, the Partnership recorded an income tax expense due to pre-tax income at its corporate subsidiaries, partially offset by a statutory rate reduction.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2018	Years Ended December 31, 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	110	80	30
Total distributions received from unconsolidated affiliates	$ 397	$ 432	$ (35)

(1) 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.

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

(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

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, 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.

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, 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, 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

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 table below presents the components of our midstream segment margin. For the years ended December 31, 2018 and 2017, the amounts previously reported for fee-based and non-fee-based margin have been adjusted to reflect reclassification of certain contractual minimum fees from fee-based margin to non-fee-based margin in order to conform to the current period classification.

	Years Ended December 31,		
	2018	2017	Change
Gathering and processing fee-based revenues	$ 1,788	$ 1,690	$ 98
Non-fee based contracts and processing (excluding unrealized gains and losses)	589	477	112
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 $98 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 $79 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.

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	$ 511	$ 415	$ 96
Transportation margin	1,233	990	243
Storage margin	211	214	(3)
Terminal Services margin	494	424	70
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 $96 million primarily due to a $106 million increase resulting from the commissioning of our fifth fractionator in July 2018 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 $70 million due to a $36 million increase resulting from a change in the classification of certain customer reimbursements previously recorded in operating expenses, a $23 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	14,384	9,877	4,507
Segment margin	2,948	1,826	1,122
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	$ 2,385	$ 1,328	$ 1,057

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 $1.18 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 gains of $280 million due to more favorable basis spreads; partially offset by an unfavorable change due to inventory valuation adjustment of $122 million; 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.

Investment in Sunoco LP

	Years Ended December 31, 2018	Years Ended December 31, 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 valuation 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	Years Ended December 31, 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

The investment in USAC segment reflects the consolidated results of 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.

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 during the periods presented above 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 impacts 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.

<u>Liquidity and Capital Resources</u>

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.

As of February 21, 2020, the Partnership expected capital expenditures in 2020 to be within the following ranges (excluding capital expenditures related to our investments in Sunoco LP and USAC):

	Growth				Maintenance			
	Low		High		Low		High	
Intrastate transportation and storage	$	20	$	30	$	40	$	45
Interstate transportation and storage [1]		100		125		140		145
Midstream		625		650		125		130
NGL and refined products transportation and services [1]		2,550		2,650		100		110
Crude oil transportation and services		500		525		165		175
All other (including eliminations)		125		150		75		80
Total capital expenditures	$	3,920	$	4,130	$	645	$	685

(1) Includes capital expenditures related to our proportionate ownership of the Bakken, Rover, and Bayou Bridge pipeline projects and our proportionate ownership of the Orbit Gulf Coast NGL export project.

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 ETO credit facilities, along with cash from operations.

As of December 31, 2019, in addition to $288 million of cash on hand, we had available capacity under the ETO Credit Facilities of $1.71 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 2020; 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, 2019, Sunoco LP had available borrowing capacity of $1.33 billion under its revolving credit facility and $21 million of cash and cash equivalents on hand.

In 2020, Sunoco LP expects to invest approximately $130 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

USAC currently plans to spend approximately $32 million in maintenance capital expenditures during 2020, including parts consumed from inventory.

Without giving effect to any equipment USAC may acquire pursuant to any future acquisitions, it currently has budgeted between $110 million and $120 million in expansion capital expenditures during 2020. As of December 31, 2019, USAC has binding commitments to purchase $49 million of additional compression units, all of which USAC expects to be delivered in 2020.

Cash Flows

Our 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 of 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 purchases 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, 2019

Cash provided by operating activities in 2019 was $8.25 billion and income from continuing operations was $5.12 billion. The difference between net income and cash provided by operating activities in 2019 primarily consisted of non-cash items totaling $3.30 billion offset by net changes in operating assets and liabilities of $448 million. The non-cash activity in 2019 consisted primarily of depreciation, depletion and amortization of $3.14 billion, impairment losses of $74 million, non-cash compensation expense of $113 million, equity in earnings of unconsolidated affiliates of $302 million, inventory valuation adjustments of $79 million, losses on extinguishment of debt of $2 million, and deferred income tax expense of $221 million. The Partnership also received distributions of $290 million from unconsolidated affiliates.

Year Ended December 31, 2018

Cash provided by operating activities in 2018 was $7.56 billion and income from continuing operations was $4.09 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 $62 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 a deferred income tax 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 $2.90 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 $122 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 in unconsolidated affiliates 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.

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, 2019

Cash used in investing activities in 2019 was $6.40 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $5.88 billion. Additional detail related to our capital expenditures is provided in the table below. During 2019, we received $93 million of cash proceeds from the sale of a noncontrolling interest in a subsidiary, paid $250 million in net cash for the SemGroup acquisition, and paid $7 million in cash for all other acquisitions. We received $54 million of cash proceeds from the sale of assets. The Partnership also received distributions of $98 million from unconsolidated affiliates.

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 net cash proceeds related to the USAC acquisition and paid $429 million in cash for all other acquisitions. We received $87 million of cash proceeds from the sale of assets. The Partnership also received distributions of $69 million from unconsolidated affiliates.

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. We received $45 million of cash proceeds from the sale of assets. The Partnership also received distributions of $135 million from unconsolidated affiliates.

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, our proportionate share of the Orbit Gulf Coast NGL export project, and net of contributions in aid of construction costs) by period:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Year Ended December 31, 2019:			
Intrastate transportation and storage	$ 87	$ 37	$ 124
Interstate transportation and storage	239	136	375
Midstream	670	157	827
NGL and refined products transportation and services	2,854	122	2,976
Crude oil transportation and services	317	86	403
Investment in Sunoco LP	108	40	148
Investment in USAC	170	30	200
All other (including eliminations)	165	50	215
Total capital expenditures	$ 4,610	$ 658	$ 5,268
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 [(1)]	72	31	103
Investment in USAC	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 [(1)]	129	48	177
All other (including eliminations)	196	72	268
Total capital expenditures	$ 5,601	$ 479	$ 6,080

(1) 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, 2019

Cash used in financing activities was $1.98 billion in 2019. During 2019, we received net proceeds of $780 million from the issuance of preferred units. Net proceeds from the offering 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 2019, we had a net increase in in our debt level of $4.70 billion. In 2019, we paid distributions of $6.28 billion to our partners and we paid distributions of $1.40 billion to noncontrolling interests. In addition, we received capital contributions of $348 million in cash from noncontrolling interests. During 2019, we incurred debt issuance costs of $117 million.

Year Ended December 31, 2018

Cash used in financing activities was $3.31 billion in 2018. During 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 Facility, to fund capital expenditures and acquisitions as well as for general partnership purposes. In 2018, we had a net increase in our debt level of $801 million. In 2018, we paid distributions of $4.56 billion to our partners and distributions of $1.17 billion to noncontrolling interests, including predecessor distributions. During 2018, we incurred debt issuance costs of $162 million, and our subsidiaries repurchased $300 million of common units in cash. In addition, we received capital contributions from noncontrolling interests of $649 million. 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 decrease 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.

Discontinued Operations

Cash flows from discontinued operations reflect cash flows related to Sunoco LP’s retail divestment.

Year Ended December 31, 2019

There were no cash flows related to discontinued operations during 2019.

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.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	December 31,	
	2019	2018
ETO Senior Notes	$ 36,118	$ 28,755
Transwestern Senior Notes	575	575
Panhandle Senior Notes	235	385
Bakken Senior Notes	2,500	—
Sunoco LP Senior Notes, Term Loan and lease-related obligations	2,935	2,307
USAC Senior Notes	1,475	725
Revolving credit facilities:		
ETO $2.00 billion Term Loan facility due October 2022	2,000	—
ETO $5.00 billion Revolving Credit Facility due December 2023	4,214	3,694
Sunoco LP $1.50 billion Revolving Credit Facility due July 2023	162	700
USAC $1.60 billion Revolving Credit Facility due April 2023	403	1,050
Bakken $2.50 billion Credit Facility due August 2019	—	2,500
HFOTCO Tax Exempt Notes due 2050	225	—
SemCAMS Revolver due February 2024	92	—
SemCAMS Term Loan A due February 2024	269	—
Other long-term debt	2	7
Unamortized premiums, net of discounts and fair value adjustments	4	31
Deferred debt issuance costs	(279)	(221)
Total debt	50,930	40,508
Less: current maturities of long-term debt	26	2,655
Long-term debt, less current maturities	$ 50,904	$ 37,853

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 included in “Item 8. Financial Statements and Supplementary Data.”

Recent Transactions

ETO January 2020 Senior Notes Offering and Redemption

On January 22, 2020, ETO completed a registered offering (the “January 2020 Senior Notes Offering”) of $1.00 billion aggregate principal amount of the Partnership’s 2.900% Senior Notes due 2025, $1.50 billion aggregate principal amount of the Partnership’s 3.750% Senior Notes due 2030 and $2.00 billion aggregate principal amount of the Partnership’s 5.000% Senior Notes due 2050, (collectively, the “Notes”). The Notes are fully and unconditionally guaranteed by the Partnership’s wholly owned subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis.

Utilizing proceeds from the January 2020 Senior Notes Offering, ETO redeemed its $400 million aggregate principal amount of 5.75% Senior Notes due September 1, 2020, its $1.05 billion aggregate principal amount of 4.15% Senior Notes due October 1, 2020, its $1.14 billion aggregate principal amount of 7.50% Senior Notes due October 15, 2020, its $250 million aggregate principal amount of 5.50% Senior Notes due February 15, 2020, ET’s $52 million aggregate principal amount of 7.50% Senior Notes due October 15, 2020 and Transwestern’s $175 million aggregate principal amount of 5.36% Senior Notes due December 9, 2020.

ETO Term Loan

On October 17, 2019, ETO entered into a term loan credit agreement (the “ETO Term Loan”) providing for a $2.00 billion three-year term loan credit facility. Borrowings under the term loan agreement mature on October 17, 2022 and are available for working capital purposes and for general partnership purposes. The term loan agreement is unsecured and is guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P.

ET-ETO Senior Notes Exchange

In February 2019, ETO commenced offers to exchange all of ET’s outstanding senior notes for senior notes issued by ETO (the “ET-ETO senior notes exchange”). Approximately 97% of ET’s outstanding senior notes were tendered and accepted, and substantially all the exchanges settled on March 25, 2019. In connection with the exchange, ETO issued approximately $4.21 billion aggregate principal amount of the following senior notes:

- $1.14 billion aggregate principal amount of 7.50% senior notes due 2020;
- $995 million aggregate principal amount of 4.25% senior notes due 2023;
- $1.13 billion aggregate principal amount of 5.875% senior notes due 2024; and
- $956 million aggregate principal amount of 5.50% senior notes due 2027.

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.

Panhandle Senior Notes Redemption

In June 2019, Panhandle’s $150 million aggregate principal amount of 8.125% senior notes matured and were repaid with borrowings under an affiliate loan agreement with ETO.

Bakken Senior Notes Offering

In March 2019, Midwest Connector Capital Company LLC, a wholly-owned subsidiary of Dakota Access, issued the following senior notes related to the Bakken pipeline:

- $650 million aggregate principal amount of 3.625% senior notes due 2022;
- $1.00 billion aggregate principal amount of 3.90% senior notes due 2024; and
- $850 million aggregate principal amount of 4.625% senior notes due 2029.

The $2.48 billion in net proceeds from the offering were used to repay in full all amounts outstanding on the Bakken credit facility and the facility was terminated.

Sunoco LP Senior Notes Offering

In March 2019, Sunoco LP issued $600 million aggregate principal amount of 6.00% senior notes due 2027 in a private placement to eligible purchasers. The net proceeds from this offering were used to repay a portion of Sunoco LP’s existing borrowings under its credit facility. In July 2019, Sunoco LP completed an exchange of these notes for registered notes with substantially identical terms.

USAC Senior Notes Offering

In March 2019, USAC issued $750 million aggregate principal amount of 6.875% senior notes due 2027 in a private placement, and in December 2019, USAC exchanged those notes for substantially identical senior notes registered under the Securities Act. The net proceeds from this offering were used to repay a portion of USAC’s existing borrowings under its 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 Term Loan

On October 17, 2019, ETO entered into a term loan credit agreement (the "ETO Term Loan") providing for a $2.00 billion three-year term loan credit facility. Borrowings under the term loan agreement mature on October 17, 2022 and are available for working capital purposes and for general partnership purposes. The term loan agreement is unsecured and is guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P.

As of December 31, 2019, the ETO Term Loan had $2.00 billion outstanding and was fully drawn. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.78%.

ETO Five-Year Credit Facility

ETO's revolving credit facility (the "ETO Five-Year Credit Facility") allows for unsecured borrowings up to $5.00 billion and matures on 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, 2019, the ETO Five-Year Credit Facility had $4.21 billion outstanding, of which $1.64 billion was commercial paper. The amount available for future borrowings was $709 million after taking into account letters of credit of $77 million. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.88%.

ETO 364-Day Facility

ETO's 364-day revolving credit facility (the "ETO 364-Day Facility") allows for unsecured borrowings up to $1.00 billion and matures on November 27, 2020. As of December 31, 2019, the ETO 364-Day Facility had no outstanding borrowings.

Sunoco LP Credit Facility

As of December 31, 2019, the Sunoco LP Credit Facility had $162 million outstanding borrowings and $8 million in standby letters of credit. The amount available for future borrowings was $1.33 billion at December 31, 2019. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 3.75%.

USAC Credit Facility

As of December 31, 2019, USAC had $403 million of outstanding borrowings and no outstanding letters of credit under the credit agreement. As of December 31, 2019, USAC had $1.20 billion of availability under its credit facility. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 4.31%.

SemCAMS Credit Facilities

SemCAMS is party to a credit agreement providing for a C$350 million (US$270 million at the December 31, 2019 exchange rate) senior secured term loan facility, a C$525 million (US$404 million at the December 31, 2019 exchange rate) senior secured revolving credit facility, and a C$300 million (US$231 million at the December 31, 2019 exchange rate) senior secured construction loan facility (the "KAPS Facility"). The term loan facility and the revolving credit facility mature on February 25, 2024. The KAPS Facility matures on June 13, 2024. SemCAMS may incur additional term loans and revolving commitments in an aggregate amount not to exceed C$250 million (US$193 million at the December 31, 2019 exchange rate), subject to receiving commitments for such additional term loans or revolving commitments from either new lenders or increased commitments from existing lenders.

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 contain 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 1.250% 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%.

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 4.04 to 1 at December 31, 2019, 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.

Panhandle's restrictive covenants include restrictions on liens securing debt and guarantees and restrictions on mergers and on the sales of assets. A breach of any of these covenants could result in acceleration of Panhandle's debt.

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) 5.5 to 1 through the end of the fiscal quarter ending December 31, 2019 and (ii) 5.0 to 1.0 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.

Covenants Related to the HFOTCO Tax Exempt Notes

The indentures covering HFOTCO's tax exempt notes due 2050 ("IKE Bonds") include customary representations and warranties and affirmative and negative covenants. Such covenants include limitations on the creation of new liens, indebtedness, making of certain restricted payments and payments on indebtedness, making certain dispositions, making material changes in business activities, making fundamental changes including liquidations, mergers or consolidations, making certain investments, entering into certain transactions with affiliates, making amendments to certain credit or organizational agreements, modifying the fiscal year, creating or dealing with hazardous materials in certain ways, entering into certain hedging arrangements, entering into certain restrictive agreements, funding or engaging in sanctioned activities, taking actions or causing the trustee to take actions that materially adversely affect the rights, interests, remedies or security of the bondholders, taking actions to remove the trustee, making certain amendments to the bond documents, and taking actions or omitting to take actions that adversely impact the tax exempt status of the IKE Bonds.

Compliance with our Covenants

We and our subsidiaries were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2019.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2019:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 51,205	$ 3,034	$ 7,204	$ 13,645	$ 27,322
Interest on long-term debt[1]	41,159	2,537	4,946	4,298	29,378
Payments on derivatives	401	150	251	—	—
Purchase commitments [2]	2,133	2,053	57	7	16
Transportation, natural gas storage and fractionation contracts	16	5	6	5	—
Operating lease obligations	1,548	98	166	140	1,144
Service concession arrangement[3]	379	15	30	32	302
Other[4]	219	27	55	48	89
Total[5]	$ 97,060	$ 7,919	$ 12,715	$ 18,175	$ 58,251

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2019. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2019. To the extent interest rates change, our contractual obligations for interest payments will change. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for further discussion.

(2) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for refined product and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the December 31, 2019 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, AROs, 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 $3.17 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, Series D and Series E preferred units declared and/or paid by the Partnership were as follows:

Period Ended	Record Date	Payment Date	Series A [1]	Series B [1]	Series C	Series D	Series E
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	—
March 31, 2019	May 1, 2019	May 15, 2019	—	—	0.4609	0.4766	—
June 30, 2019	August 1, 2019	August 15, 2019	31.2500	33.1250	0.4609	0.4766	0.5806 *
September 30, 2019	November 1, 2019	November 15, 2019	—	—	0.4609	0.4766	0.4750
December 31, 2019	February 3, 2020	February 18, 2020	31.2500	33.1250	0.4609	0.4766	0.4750

* Represent prorated initial distributions. Prorated initial distributions on the recently issued Series F and Series G preferred units will be payable in May 2020.

(1) Series A Preferred Units and Series B Preferred Unit distributions are paid on a semi-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, 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
March 31, 2019	May 7, 2019	May 15, 2019	0.8255
June 30, 2019	August 6, 2019	August 14, 2019	0.8255
September 30, 2019	November 5, 2019	November 19, 2019	0.8255
December 31, 2019	February 7, 2020	February 19, 2020	0.8255

USAC Cash Distributions

Subsequent to the Energy Transfer Merger and USAC Transactions described in Note 1 and Note 3, respectively, ETO owned approximately 39.7 million USAC common units and 6.4 million USAC Class B units. Subsequent to the conversion of the USAC Class B Units to USAC common units on July 30, 2019, ETO owns approximately 46.1 million USAC common units. As of December 31, 2019, USAC had approximately 96.6 million common units outstanding. USAC currently has a non-economic general partner interest and no outstanding IDRs.

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
March 31, 2019	April 29, 2019	May 10, 2019	0.5250
June 30, 2019	July 29, 2019	August 9, 2019	0.5250
September 30, 2019	October 28, 2019	November 8, 2019	0.5250
December 31, 2019	January 27, 2020	February 7, 2020	0.5250

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, 2019 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation, depletion and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Revenue Recognition. Revenues for sales of natural gas and NGLs are recognized at the later of the time of delivery of the product to the customer or the time of sale. Revenues from service labor, transportation, treating, compression and gas processing, are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available.

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

Our intrastate transportation and storage segment also generates revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from our marketing operations, and from producers at the wellhead.

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

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. Our midstream segment also generates revenues from the sale of residue gas and NGLs at the tailgate of our processing facilities primarily to affiliates and some third-party customers.

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

We conduct marketing activities in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

We have a risk management policy that provides for oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to senior management and predefined limits and authorizations set forth in our risk management policy.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot prices and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

NGL storage and pipeline transportation revenues are recognized when services are performed or products are delivered, respectively. Fractionation and processing revenues are recognized when product is either loaded into a truck or injected into a third-party pipeline, which is when title and risk of loss pass to the customer.

In our natural gas compression business, revenue is recognized for compressor packages and technical service jobs using the completed contract method which recognizes revenue upon completion of the job. Costs incurred on a job are deducted at the time revenue is recognized.

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

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. 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.

Lease Accounting. At the inception of each lease arrangement, we determine if the arrangement is a lease or contains an embedded lease and review the facts and circumstances of the arrangement to classify lease assets as operating or finance leases under Topic 842. The Partnership has elected not to record any leases with terms of 12 months or less on the balance sheet.

Balances related to operating leases are included in operating lease ROU assets, accrued and other current liabilities, operating lease current liabilities and non-current operating lease liabilities in our consolidated balance sheets. Finance leases represent a small portion of the active lease agreements and are included in finance lease ROU assets, current maturities of long-term debt and long-term debt, less current maturities in our consolidated balance sheets. The ROU assets represent the Partnership's right to use an underlying asset for the lease term and lease liabilities represent the obligation of the Partnership to make minimum lease payments arising from the lease for the duration of the lease term.

Most leases include one or more options to renew, with renewal terms that can extend the lease term from one to 20 years or greater. The exercise of lease renewal options is typically at the sole discretion of the Partnership and lease extensions are evaluated on a lease-by-lease basis. Leases containing early termination clauses typically require the agreement of both parties to the lease. At the inception of a lease, all renewal options reasonably certain to be exercised are considered when determining the lease term. The depreciable life of lease assets and leasehold improvements are limited by the expected lease term.

To determine the present value of future minimum lease payments, we use the implicit rate when readily determinable. Presently, because many of our leases do not provide an implicit rate, the Partnership applies its incremental borrowing rate based on the information available at the lease commencement date to determine the present value of minimum lease payments. The operating and finance lease ROU assets include any lease payments made and exclude lease incentives.

Minimum rent payments are expensed on a straight-line basis over the term of the lease. In addition, some leases require additional contingent or variable lease payments, which are based on the factors specific to the individual agreement. Variable lease payments the Partnership is typically responsible for include payment of real estate taxes, maintenance expenses and insurance.

For short-term leases (leases that have term of twelve months or less upon commencement), lease payments are recognized on a straight-line basis and no ROU assets are recorded.

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 $5.17 billion of goodwill on the Partnership's consolidated balance sheet as of December 31, 2019, approximately $380 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, 2019, the Partnership recorded the following impairments:

- A $12 million impairment was recorded related to the goodwill associated with the Partnership's Southwest Gas operations within the interstate segment primarily due to decreases in projected future revenues and cash flows. Additionally, the Partnership recorded a $9 million impairment related to the goodwill associated with the Partnership's North Central operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows.
- Sunoco LP recognized a $47 million write-down on assets held for sale related to its ethanol plant in Fulton, New York.
- USAC also recognized a $6 million fixed asset impairment related to certain idle compressor assets.

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.
- 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 assets were 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.
- 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.

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, 2019, 2018 and 2017 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 a total of $17 million in impairment charges on their contractual rights and liquor licenses primarily due to decreases in projected future revenues and cash flows from the date the intangible assets were 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 ARO 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 AROs as of December 31, 2019 and 2018, 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. ETC Sunoco 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, ETC Sunoco is legally or contractually required to abandon in place or remove the asset. We believe we may have additional AROs related to ETC Sunoco'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.

Other non-current assets on the Partnership's consolidated balance sheet included $31 million and $26 million of legally restricted funds for the purpose of settling AROs as of December 31, 2019 and 2018, respectively.

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 $320 million in environmental accruals as of December 31, 2019.

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 $936 million have been included in ETO's consolidated balance sheet as of December 31, 2019. The state NOL carryforward benefits of $149 million ($118 million net of federal benefit) begin to expire in 2019 with a substantial portion expiring between 2033 and 2039. ETO's corporate subsidiaries have federal NOLs of $3.42 billion ($718 million in benefits) of which $1.29 billion will expire between 2031 and 2037. Any federal NOL generated in 2018 and future years can be carried forward indefinitely. Federal alternative minimum tax credit carryforwards of $15 million remained at December 31, 2019. We have determined that a valuation allowance totaling $62 million ($49 million net of federal income tax effects) is required for the state NOLs at December 31, 2019 primarily due to significant restrictions on their use in the Commonwealth of Pennsylvania. A separate valuation allowance of $46 million is attributable to foreign tax credits. In making the assessment of the future realization of the deferred tax assets, we rely on future reversals of existing taxable temporary differences, tax planning strategies and forecasted taxable income based on historical and projected future operating results. The potential need for valuation allowances is regularly reviewed by management. If it is more likely than not that the recorded asset will not be realized, additional valuation allowances which increase income tax expense may be recognized in the period such determination is made. Likewise, if it is more likely than not that additional deferred tax assets will be realized, an adjustment to the deferred tax asset will increase income in the period such determination is made.

Forward-Looking Statements

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this annual report, words such as “anticipate,” “project,” “expect,” “plan,” “goal,” “forecast,” “estimate,” “intend,” “could,” “believe,” “may,” “will” and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our processing and treating facilities;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;

- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third-party contractors;
- the availability and cost of capital and our ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which we own less than a controlling interests, including risks related to management actions at such entities that we may not be able to control or exert influence;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;
- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations; and
- the costs and effects of legal and administrative proceedings.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risks described under “Item 1A. Risk Factors” in this annual report. Any forward-looking statement made by us in this Annual Report on Form 10-K is based only on information currently available to us and speaks only as of the date on which it is made. We undertake no obligation to publicly update any forward-looking statement, whether written or oral, that may be made from time to time, whether as a result of new information, future developments or otherwise.

Inflation

Interest rates on existing and future credit facilities and future debt offerings could be significantly higher than current levels, causing our financing costs to increase accordingly. Although increased financing costs could limit our ability to raise funds in the capital markets, we expect to remain competitive with respect to acquisitions and capital projects since our competitors would face similar circumstances.

Inflation in the United States has been relatively low in recent years and has not had a material effect on our results of operations. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. Our operating revenues and costs are influenced to a greater extent by commodity price changes. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along a portion of increased costs to our customers in the form of higher fees.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements starting on page F-1 of this report are incorporated by reference.

INDEX TO FINANCIAL STATEMENTS
Energy Transfer Operating, L.P. and Subsidiaries

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 the financial statements
We have audited the accompanying consolidated balance sheets of Energy Transfer Operating, L.P. (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

Change in accounting principles
As discussed in Note 2 to the consolidated financial statements, the Partnership has changed its method of accounting for leases due to the adoption of the new leasing standard. The Partnership adopted the new leasing standard by recognizing a cumulative catch-up adjustment to the opening balance sheet as of January 1, 2019. Additionally, as discussed in Note 2, the consolidated financial statements have been retrospectively adjusted to reflect the Partnership’s change in method of accounting for certain inventories.

Acquisition of SemGroup
As discussed in Note 3, the accompanying consolidated financial statements have been retrospectively adjusted to reflect an acquisition of entities under common control.

Basis for opinion
These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on the Partnership’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Board (United States) (“PCAOB”) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership’s internal control over financial reporting. Accordingly, we express no such opinion.

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

Critical audit matters
The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Goodwill Impairment Assessment

As discussed in Note 2 of the consolidated financial statements, of the $5.17 billion of goodwill on the Partnership's consolidated balance sheet as of December 31, 2019, approximately $380.0 million is recorded in a reporting unit for which the estimated fair value exceeded the carrying value by less than 20% in the most recent quantitative test. The Partnership engaged third party valuation specialists for the estimation of the fair value of this reporting unit. We identified the estimation of the fair value of the reporting unit as a critical audit matter.

The principal considerations for our determination that the estimation of the fair value of the reporting unit was a critical audit matter are that the extent to which the fair value of the reporting unit exceeds its carrying value is relatively low, the estimate of the future cash flows, including projected growth rates, forecasted costs, discount rates and future market conditions requires a high degree of judgement, and the application of valuation methodologies can be complex.

Our audit procedures related to the estimation of the fair value of the reporting unit included the following procedures, among others. We tested the effectiveness of controls relating to management's review of the assumptions used to develop the future cash flows, the reconciliation of cash flows prepared by management to the data used in the third party valuation reports, the discount rates used, and valuation methodologies applied. In addition to testing the effectiveness of controls, we also performed the following:

- Compared the actual current results of the relevant reporting unit to the expected performance of that reporting unit based on prior period financial forecasts, as applicable.
- Utilized an internal valuation specialist to evaluate:
    - The methodologies used and whether they were acceptable for the underlying assets or operations and being applied correctly by performing independent calculations,
    - The appropriateness of the discount rates by recalculating the weighted average costs of capital, and
    - The qualifications of the third party valuation specialists engaged by the Partnership based on their credentials and experience.
- Tested the reasonableness of the projected growth rate and forecasted costs by comparing such items to historical operating results of the relevant reporting unit and by assessing the likelihood or capability of the reporting unit to undertake activities or initiatives underpinning significant drivers of growth in the forecasted period.

SemGroup Acquisition

As discussed in Note 3 to the consolidated financial statements, Energy Transfer LP contributed a controlling interest in SemGroup Corporation (SemGroup) to the Partnership. This contribution was accounted for as a reorganization of entities under common control. Prior to Energy Transfer LP's contribution, Energy Transfer LP completed its acquisition of SemGroup in December 2019 and the assets acquired and liabilities assumed were required to be estimated and recorded at fair value as of the transaction date, for which the Partnership utilized a third party valuation specialist. The contributed entities' assets and liabilities were not adjusted as of the contribution date. We identified the estimation of the fair value of the assets acquired and liabilities assumed in Energy Transfer LP's acquisition of SemGroup as a critical audit matter.

The principal considerations for our determination that the estimation of the fair value of the assets acquired and liabilities assumed in the acquisition of SemGroup was a critical audit matter are that there was a high degree of estimation uncertainty due to significant judgements with respect to the selection of the valuation methodologies applied, the assumptions used to estimate the future revenues and cash flows, including revenue growth rates, forecasted costs, discount rates and future market conditions in the determination of the fair value of the intangible assets acquired, and the estimation of replacement costs of the property, plant and equipment acquired. This required an increased extent of effort when performing audit procedures to evaluate the reasonableness of management's estimates and assumptions related to the fair value of the assets acquired and liabilities assumed, including the need to involve our fair value specialists.

Our audit procedures responsive to the estimation of the fair value of the assets acquired and liabilities assumed in the acquisition of SemGroup included the following procedures, among others. We tested the effectiveness of controls relating to management's review of the assumptions used to develop the future revenues and cash flows, the reconciliation of future revenues and cash flows prepared by management to the data used in the third party valuation report, the review of estimated replacement cost of property, plant and equipment as compared to current carrying values, and the valuation methodologies applied. In addition to testing the effectiveness of controls, we also performed the following:

- Utilized an internal valuation specialist to evaluate:
    - The methodologies used and whether they were acceptable for the underlying assets or operations and being applied correctly by performing an independent calculation,

    - The appropriateness of the replacement cost of property plant, and equipment, by performing an independent calculation and inspecting the estimated remaining years of service for the underlying assets based on the original acquisition dates and condition of assets,
    - The appropriateness of the discount rate by recalculating the weighted average costs of capital, and
    - The qualifications of the third party valuation specialist engaged by the Partnership based on their credentials and experience.
- Tested the revenue growth rates and forecasted costs of SemGroup by comparing such items to the historical operating results of the acquired entity and by assessing the likelihood or capability of the acquired entity to undertake activities or initiatives underpinning significant drivers of growth in the forecasted period.

Environmental Remediation
As discussed in Note 10 of the consolidated financial statements, the Partnership's operations are subject to extensive federal, tribal, state and local environmental and safety laws and regulations that require expenditures for remediation at current and former facilities. We identified the identification, assessment and estimation of the environmental exposure associated with certain sites of ETC Sunoco Holdings LLC as a critical audit matter.

The principal considerations for our determination that the identification, assessment and estimation of the environmental exposure was a critical audit matter are that there was a high estimation uncertainty due to the complexity of the actuarial methods utilized, the discount rate applied and the potential for changes in the timing and extent of remediation. This required an increased extent of effort when performing audit procedures, related to identification, assessment and estimation of the environmental exposure, including the need to involve actuarial specialists.

Our audit procedures related to the identification, assessment and estimation of the Partnership's environmental exposure included the following procedures, among others. We tested the effectiveness of controls relating to the identification and review of the historical claims, payments and reserve data provided to the third party actuary specialist and the reconciliation of that data to that used in the actuary report, and the review of the discount rate and actuarial methods applied. In addition to testing the effectiveness of controls, we performed the following procedures:

- Utilized an external actuarial specialist to evaluate:
    - The methodologies used and whether they were acceptable for the underlying operations,
    - The qualifications of the third party actuary specialist engaged by the Partnership based on their credentials and experience.
- Evaluated the appropriateness of the discount rate used by comparing it to the historical rate of return from the captive insurance company's investment portfolio used to fund the underlying liabilities, and
- Evaluated the life-to-date payments, reserves, and payment patterns by agreeing the historical claims and payment amounts to the underlying claims or general ledger.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2004.

Dallas, Texas
November 12, 2020

ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 288	$ 418
Accounts receivable, net	5,038	4,009
Accounts receivable from related companies	167	176
Inventories	1,532	1,372
Income taxes receivable	146	73
Derivative assets	23	111
Other current assets	291	356
Total current assets	7,485	6,515
Property, plant and equipment	89,294	79,280
Accumulated depreciation and depletion	(15,398)	(12,625)
	73,896	66,655
Advances to and investments in unconsolidated affiliates	3,454	2,636
Lease right-of-use assets, net	964	—
Other non-current assets, net	1,571	1,478
Long-term affiliate receivable	3,603	440
Intangible assets, net	6,154	6,000
Goodwill	5,167	4,885
Total assets	$ 102,294	$ 88,609

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

ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2019	December 31, 2018
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 4,119	$ 3,491
Accounts payable to related companies	31	119
Derivative liabilities	147	185
Operating lease current liabilities	60	—
Accrued and other current liabilities	3,336	2,847
Current maturities of long-term debt	26	2,655
Total current liabilities	7,719	9,297
Long-term debt, less current maturities	50,904	37,853
Non-current derivative liabilities	273	104
Non-current operating lease liabilities	901	—
Deferred income taxes	3,171	2,884
Other non-current liabilities	1,162	1,184
Commitments and contingencies		
Redeemable noncontrolling interests	739	499
Equity:		
Limited Partners:		
Series A Preferred Unitholders (950,000 units authorized, issued and outstanding as of December 31, 2019 and 2018, respectively)	958	958
Series B Preferred Unitholders (550,000 units authorized, issued and outstanding as of December 31, 2019 and 2018, respectively)	556	556
Series C Preferred Unitholders (18,000,000 units authorized, issued and outstanding as of December 31, 2019 and 2018, respectively)	440	440
Series D Preferred Unitholders (17,800,000 units authorized, issued and outstanding as of December 31, 2019 and 2018, respectively)	434	434
Series E Preferred Unitholders (32,000,000 units authorized, issued and outstanding as of December 31, 2019)	786	—
Common Unitholders and Other	24,226	26,539
Accumulated other comprehensive loss	(18)	(42)
Total partners' capital	27,382	28,885
Noncontrolling interests	8,018	7,903
Predecessor equity	2,025	—
Total equity	37,425	36,788
Total liabilities and equity	$ 102,294	$ 88,609

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

ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions, except per unit data)

	Years Ended December 31,		
	2019	2018	2017
REVENUES:			
Refined product sales	$ 16,752	$ 17,458	$ 11,166
Crude sales	15,917	14,425	10,706
NGL sales	8,290	9,986	7,781
Gathering, transportation and other fees	9,086	6,797	4,435
Natural gas sales	3,295	4,452	4,172
Other	873	969	2,263
Total revenues	54,213	54,087	40,523
COSTS AND EXPENSES:			
Cost of products sold	39,801	41,603	31,017
Operating expenses	3,294	3,089	2,644
Depreciation, depletion and amortization	3,136	2,843	2,541
Selling, general and administrative	686	664	568
Impairment losses	74	431	1,039
Total costs and expenses	46,991	48,630	37,809
OPERATING INCOME	7,222	5,457	2,714
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(2,262)	(1,709)	(1,575)
Equity in earnings of unconsolidated affiliates	302	344	144
Impairment of investments in unconsolidated affiliates	—	—	(313)
Losses on extinguishments of debt	(2)	(109)	(42)
Gains (losses) on interest rate derivatives	(241)	47	(37)
Other, net	295	69	206
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	5,314	4,099	1,097
Income tax expense (benefit) from continuing operations	199	5	(1,804)
INCOME FROM CONTINUING OPERATIONS	5,115	4,094	2,901
Loss from discontinued operations, net of income taxes	—	(265)	(177)
NET INCOME	5,115	3,829	2,724
Less: Net income attributable to noncontrolling interests	1,051	715	420
Less: Net income attributable to redeemable noncontrolling interests	51	39	—
Less: Net income (loss) attributable to predecessor	—	(5)	274
NET INCOME ATTRIBUTABLE TO PARTNERS	$ 4,013	$ 3,080	$ 2,030

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

ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in millions)

	Years Ended December 31,		
	2019	2018	2017
Net income	$ 5,115	$ 3,829	$ 2,724
Other comprehensive income (loss), net of tax:			
Change in value of available-for-sale securities	11	(4)	6
Actuarial gain (loss) relating to pension and other postretirement benefits	24	(43)	(12)
Foreign currency translation adjustment	6	—	—
Change in other comprehensive income from unconsolidated affiliates	(10)	4	1
	31	(43)	(5)
Comprehensive income	5,146	3,786	2,719
Less: Comprehensive income attributable to noncontrolling interests	1,051	715	420
Less: Comprehensive income attributable to redeemable noncontrolling interests	51	39	—
Less: Comprehensive income (loss) attributable to predecessor	—	(5)	274
Comprehensive income attributable to partners	$ 4,044	$ 3,037	$ 2,025

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

ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)

	Limited Partners						
	Preferred Unitholders	Common Unitholders and Other	General Partner	AOCI	Non-controlling Interest	Predecessor Equity	Total
Balance, December 31, 2016	$ —	$ 18,570	$ 206	$ 8	$ 7,820	$ 2,497	$ 29,101
Distributions to partners	—	(2,516)	(952)	—	—	—	(3,468)
Distributions to noncontrolling interests	—	—	—	—	(430)	(284)	(714)
Partnership units issued for cash	1,479	2,283	—	—	—	—	3,762
Subsidiary units issued for cash	—	—	—	—	—	333	333
Sunoco Logistics Merger	—	5,938	—	—	(5,938)	—	—
Capital contributions from noncontrolling interests	—	—	—	—	2,202	—	2,202
Sale of Bakken pipeline interest	—	1,260	—	—	740	—	2,000
Sale of Rover pipeline interest	—	93	—	—	1,385	—	1,478
Acquisition of PennTex noncontrolling interest	—	(48)	—	—	(232)	—	(280)
Other comprehensive loss, net of tax	—	—	—	(5)	—	—	(5)
Other, net	—	35	—	—	(85)	(4)	(54)
Net income	12	1,028	990	—	420	274	2,724
Balance, December 31, 2017	1,491	26,643	244	3	5,882	2,816	37,079
Distributions to partners	(100)	(3,376)	(1,080)	—	—	—	(4,556)
Distributions to noncontrolling interests	—	—	—	—	(891)	(276)	(1,167)
Partnership units issued for cash	867	58	—	—	—	—	925
Subsidiary units repurchased	—	—	—	—	—	(300)	(300)
Energy Transfer Merger	—	1,370	(340)	—	1,474	(2,504)	—
Capital contributions from noncontrolling interests	—	—	—	—	649	—	649
Cumulative effect adjustment due to change in accounting principle	—	—	—	—	—	(54)	(54)
Deemed distribution, net	—	37	—	—	58	(497)	(402)
Acquisition of USAC	—	—	—	—	—	832	832
Other comprehensive loss, net of tax	—	—	—	(43)	—	—	(43)
Other, net	(3)	53	(17)	(2)	16	(12)	35
Net income (loss), excluding amounts attributable to redeemable noncontrolling interests	133	1,754	1,193	—	715	(5)	3,790
Balance, December 31, 2018	2,388	26,539	—	(42)	7,903	—	36,788
Distributions to partners	(197)	(6,087)	—	—	—	—	(6,284)
Distributions to noncontrolling interests	—	—	—	—	(1,399)	(2)	(1,401)
Partnership units issued for cash	780	—	—	—	—	—	780
SemGroup Acquisition	—	—	—	—	—	2,008	2,008
Capital contributions from noncontrolling interests	—	—	—	—	348	—	348
Sale of noncontrolling interest in subsidiary	—	—	—	—	93	—	93
Other comprehensive loss, net of tax	—	—	—	24	—	15	39
Other, net	(1)	(32)	—	—	22	1	(10)
Net income, excluding amounts attributable to redeemable noncontrolling interests	204	3,806	—	—	1,051	3	5,064
Balance, December 31, 2019	3,174	24,226	—	(18)	8,018	2,025	37,425

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

ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES:			
Net income	$ 5,115	$ 3,829	$ 2,724
Reconciliation of net income to net cash provided by operating activities:			
Loss from discontinued operations	—	265	177
Depreciation, depletion and amortization	3,136	2,843	2,541
Deferred income taxes	221	(8)	(1,841)
Inventory valuation adjustments	(79)	85	(24)
Non-cash compensation expense	113	105	99
Impairment losses	74	431	1,039
Impairment of investments in unconsolidated affiliates	—	—	313
Losses on extinguishment of debt	2	109	42
Distributions on unvested awards	(9)	(33)	(35)
Equity in earnings of unconsolidated affiliates	(302)	(344)	(144)
Distributions from unconsolidated affiliates	290	328	297
Other non-cash	132	(113)	(249)
Net change in operating assets and liabilities, net of effects of acquisitions	(448)	62	(122)
Net cash provided by operating activities	8,245	7,559	4,817
INVESTING ACTIVITIES:			
Cash proceeds from sale of noncontrolling interest in subsidiary	93	—	—
Cash proceeds from USAC acquisition, net of cash received	—	711	—
Cash proceeds from Bakken pipeline transaction	—	—	2,000
Cash proceeds from Rover pipeline transaction	—	—	1,478
Cash paid for acquisition of PennTex noncontrolling interest	—	—	(280)
Cash funded in SemGroup Acquisition, net of cash held by SemGroup at acquisition	(250)	—	—
Cash paid for all other acquisitions	(7)	(429)	(303)
Capital expenditures, excluding allowance for equity funds used during construction	(5,960)	(7,407)	(8,444)
Contributions in aid of construction costs	80	109	24
Contributions to unconsolidated affiliates	(523)	(26)	(268)
Distributions from unconsolidated affiliates in excess of cumulative earnings	98	69	135
Proceeds from the sale of assets	54	87	45
Other	18	(16)	1
Net cash used in investing activities	(6,397)	(6,902)	(5,612)

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

FINANCING ACTIVITIES:			
Proceeds from borrowings	22,583	28,538	29,389
Repayments of debt	(18,881)	(27,297)	(29,387)
Proceeds from (repayments of) notes payable to related party	995	(440)	(423)
Common units issued for cash	—	58	2,283
Preferred units issued for cash	780	867	1,479
Redeemable noncontrolling interests issued for cash	—	465	—
Predecessor units issued for cash	—	—	333
Capital contributions from noncontrolling interests	348	649	1,214
Distributions to partners	(6,284)	(4,556)	(3,468)
Predecessor distributions to partners	—	(276)	(284)
Distributions to noncontrolling interests	(1,401)	(891)	(430)
Distributions to redeemable noncontrolling interests	—	(24)	—
Repurchases of common units	—	(24)	—
Subsidiary repurchases of common units	—	(300)	—
Redemption of Legacy ETP Preferred Units	—	—	(53)
Debt issuance costs	(117)	(162)	(83)
Other	(1)	85	2
Net cash provided by (used in) financing activities	(1,978)	(3,308)	572
DISCONTINUED OPERATIONS:			
Operating activities	—	(484)	136
Investing activities	—	3,207	(38)
Changes in cash included in current assets held for sale	—	11	(5)
Net increase in cash and cash equivalents of discontinued operations	—	2,734	93
Increase (decrease) in cash and cash equivalents	(130)	83	(130)
Cash and cash equivalents, beginning of period	418	335	465
Cash and cash equivalents, end of period	$ 288	$ 418	$ 335

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

ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar and unit amounts are in millions)

1. OPERATIONS AND BASIS OF PRESENTATION:

The consolidated financial statements presented herein contain the results of Energy Transfer Operating, L.P. and its subsidiaries (the “Partnership,” “we,” “us,” “our” or “ETO”).

ETO is a consolidated subsidiary of Energy Transfer LP. 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, the former common 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.

The Energy Transfer Merger was a combination of entities under common control; therefore, Sunoco LP, Lake Charles LNG and USAC’s (see Note 3 for more information) assets and liabilities were not adjusted. The Partnership’s consolidated financial statements have been retrospectively adjusted to reflect consolidation beginning January 1, 2017 of Sunoco LP and Lake Charles LNG and April 2, 2018 of USAC (the date ET acquired USAC, see Note 3). Predecessor equity included on the consolidated financial statements for periods prior to the Energy Transfer Merger in October 2018, represents Sunoco LP, Lake Charles LNG and USAC’s equity prior to the Energy Transfer Merger.

Following the closing of the Energy Transfer Merger, Energy Transfer Equity, L.P. changed its name to “Energy Transfer LP” and its common units began trading on the New York Stock Exchange under the “ET” ticker symbol on Friday, October 19, 2018. In addition, Energy Transfer Partners, L.P. changed its name to “Energy Transfer Operating, L.P.” For purposes of maintaining clarity, the following references are used herein:

- References to “ETO” refer to the entity named Energy Transfer Partners, L.P. prior to the close of the Energy Transfer Merger and Energy Transfer Operating, L.P. subsequent to the close of the Energy Transfer Merger; and
- References to “ET” refer to the entity named Energy Transfer Equity, L.P. prior to the close of the Energy Transfer Merger and Energy Transfer LP subsequent to the close of the Energy Transfer Merger.

In April 2017, Energy Transfer Partners, L.P. and Sunoco Logistics completed the previously announced merger transaction in which Sunoco Logistics acquired Energy Transfer Partners, L.P. in a unit-for-unit transaction (the “Sunoco Logistics Merger”). Under the terms of the transaction, Energy Transfer Partners, L.P. unitholders received 1.5 common units of Sunoco Logistics for each common unit of Energy Transfer Partners, L.P. they owned. Under the terms of the merger agreement, Sunoco Logistics’ general partner was merged with and into ETP GP, with ETP GP surviving as an indirect wholly-owned subsidiary of ET. In connection with the merger, the Energy Transfer Partners, L.P. Class H units were cancelled. The outstanding Energy Transfer Partners, L.P. Class E units, Class G units, Class I units and Class K units at the effective time of the merger were converted into an equal number of newly created classes of Sunoco Logistics units, with the same rights, preferences, privileges, duties and obligations as such classes of Energy Transfer Partners, L.P. units had immediately prior to the closing of the merger. Additionally, the outstanding Sunoco Logistics common units and Sunoco Logistics Class B units owned by Energy Transfer Partners, L.P. at the effective time of the merger were cancelled.

In connection with the Sunoco Logistics Merger, Sunoco Logistics Partners L.P. changed its name to “Energy Transfer Partners, L.P.” For purposes of maintaining clarity, the following references are used herein:

- References to “Sunoco Logistics” refer to the entity named Sunoco Logistics Partners L.P. and its subsidiaries prior to the close of the Sunoco Logistics Merger; and
- References to “ETO” for periods prior to the Sunoco Logistics Merger refer to the consolidated entity named Energy Transfer Partners, L.P. and its subsidiaries prior to the close of the Sunoco Logistics Merger.

The Sunoco Logistics Merger resulted in Energy Transfer Partners, L.P. being treated as the surviving consolidated entity from an accounting perspective, while Sunoco Logistics (prior to changing its name to "Energy Transfer Partners, L.P.") was the surviving consolidated entity from a legal and reporting perspective. Therefore, for the pre-merger periods, the consolidated financial statements reflect the consolidated financial statements of the legal acquiree (i.e., the entity that was named "Energy Transfer Partners, L.P." prior to the merger and name changes).

The Sunoco Logistics Merger was accounted for as an equity transaction. The Sunoco Logistics Merger did not result in any changes to the carrying values of assets and liabilities in the consolidated financial statements, and no gain or loss was recognized. For the periods prior to the Sunoco Logistics Merger, the Sunoco Logistics limited partner interests that were owned by third parties (other than Energy Transfer Partners, L.P. or its consolidated subsidiaries) are presented as noncontrolling interests in these consolidated financial statements.

The historical common units amount presented in these consolidated financial statements have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange in connection with the Sunoco Logistics Merger.

The Partnership is engaged in the gathering and processing, compression, treating and transportation of natural gas, focusing on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Utica, Bone Spring and Avalon shales.

The Partnership owns and operates intrastate natural gas pipeline systems and storage facilities that are engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico and West Virginia.

The Partnership owns and operates interstate pipelines, either directly or through equity method investments, that transport natural gas to various markets in the United States.

The Partnership owns and operates a logistics business, consisting of a geographically diverse portfolio of complementary pipeline, terminalling, and acquisition and marketing assets, which are used to facilitate the purchase and sale of crude oil, NGLs and refined products.

The Partnership owns a controlling interest in Sunoco LP which is engaged in the wholesale distribution of motor fuels to convenience stores, independent dealers, commercial customers, and distributors, as well as the retail sale of motor fuels and merchandise through Sunoco LP operated convenience stores and retail fuel sites. As of December 31, 2019, our interest in Sunoco LP consisted of 100% of the general partner and IDRs, as well as 28.5 million common units.

The Partnership owns a controlling interest in USAC which provides compression services to producers, processors, gatherers and transporters of natural gas and crude oil. As of December 31, 2019, our interest in USAC consisted of 100% of the general partner and 46.1 million common units.

Basis of Presentation. The consolidated financial statements of the Partnership have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year amounts have been conformed to the current year presentation. These reclassifications had no impact on net income or total equity. Management evaluated subsequent events through the date the financial statements were issued.

The consolidated financial statements of the Partnership presented herein include the results of operations of our controlled subsidiaries, including Sunoco LP and USAC.

For prior periods herein, certain balances have been reclassified to assets and liabilities held for sale and certain revenues and expenses to discontinued operations. These reclassifications had no impact on net income or total equity.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream, NGL and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the estimated operating results represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Change in Accounting Policy

Effective January 1, 2020, the Partnership elected to change its accounting policy related to certain barrels of crude oil that were previously accounted for as inventory. Under the revised accounting policy, certain amounts of crude oil that are not available for sale have been reclassified from inventory to non-current assets. These crude oil barrels, which are owned by the Partnership's crude oil acquisition and marketing business, include pipeline linefill and tank bottoms and are not considered to be available for sale because the volumes must be maintained in order to continue normal operation of the related pipelines or tanks and because there is no expectation of liquidation or sale of these volumes in the near term.

Under the previous accounting policy, all crude oil barrels were recorded as inventory under the weighted average cost method. Under the revised accounting policy, barrels related to pipeline linefill and tank bottoms are accounted for as long-lived assets and reflected as non-current assets on the consolidated balance sheet. These crude oil barrels will be tested for impairment consistent with the Partnership's existing accounting policy for impairments of long-lived assets. The Partnership's management believes that the change in accounting policy is preferable as it more closely aligns the accounting policies across the consolidated entity, given that similar assets in the Partnership's natural gas, NGLs and refined products businesses are accounted for as non-current assets. In addition, management believes that reflecting these crude oil barrels as non-current assets better represents the economic results of the Partnership's crude oil acquisition and marketing business by reducing volatility resulting from market price adjustments to crude oil barrels that are not expected to be sold or liquidated in the near term.

As a result of this change in accounting policy, the Partnership's consolidated balance sheets for prior periods have been retrospectively adjusted as follows:

	December 31, 2019			December 31, 2018		
	As Originally Reported*	Effect of Change	As Adjusted	As Originally Reported	Effect of Change	As Adjusted
Inventories	$ 1,935	$ (403)	$ 1,532	$ 1,677	$ (305)	$ 1,372
Total current assets	7,888	(403)	7,485	6,820	(305)	6,515
Other non-current assets, net	1,075	496	1,571	1,006	472	1,478
Total assets	102,201	93	102,294	88,442	167	88,609
Total partners' capital	27,289	93	27,382	28,718	167	28,885

* Amounts reflect the retrospective consolidation of the SemGroup entities discussed above.

The balances in partners' capital were also adjusted by $112 million and $163 million as of December 31, 2017 and 2016, respectively, in connection with the change in accounting policy discussed above.

In addition, the Partnership’s consolidated statements of operations, comprehensive income and cash flows for prior periods have been retrospectively adjusted as follows:

	Year Ended December 31,		
	2019*	2018	2017
As originally reported:			
Consolidated Statements of Operations and Comprehensive Income			
Cost of products sold	$ 39,727	$ 41,658	$ 30,966
Operating income	7,296	5,402	2,765
Income from continuing operations before income tax expense	5,388	4,044	1,148
Net income	5,189	3,774	2,775
Comprehensive income	5,220	3,731	2,770
Comprehensive income attributable to partners	4,118	2,982	2,076
Consolidated Statements of Cash Flows			
Net income	5,189	3,774	2,775
Net change in operating assets and liabilities	(522)	117	(173)
Effect of change:			
Consolidated Statements of Operations and Comprehensive Income			
Cost of products sold	74	(55)	51
Operating income	(74)	55	(51)
Income from continuing operations before income tax expense	(74)	55	(51)
Net income	(74)	55	(51)
Comprehensive income	(74)	55	(51)
Comprehensive income attributable to partners	(74)	55	(51)
Consolidated Statements of Cash Flows			
Net income	(74)	55	(51)
Net change in operating assets and liabilities	74	(55)	51
As adjusted:			
Consolidated Statements of Operations and Comprehensive Income			
Cost of products sold	39,801	41,603	31,017
Operating income	7,222	5,457	2,714
Income from continuing operations before income tax expense	5,314	4,099	1,097
Net income	5,115	3,829	2,724
Comprehensive income	5,146	3,786	2,719
Comprehensive income attributable to partners	4,044	3,037	2,025
Consolidated Statements of Cash Flows			
Net income	5,115	3,829	2,724
Net change in operating assets and liabilities	(448)	62	(122)

* Amounts reflect the retrospective consolidation of the SemGroup entities discussed above.

Lease Accounting

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, *Leases (Topic 842)*, which has amended the FASB Accounting Standards Codification ("ASC") and introduced Topic 842, Leases. On January 1, 2019, the Partnership has adopted ASC Topic 842 ("Topic 842"), which is effective for interim and annual reporting periods beginning on or after December 15, 2018. Topic 842 requires entities to recognize lease assets and liabilities on the balance sheet for all leases with a term of more than one year, including operating leases, which historically were not recorded on the balance sheet in accordance with the prior standard.

To adopt Topic 842, the Partnership recognized a cumulative catch-up adjustment to the opening balance sheet as of January 1, 2019 related to certain leases that existed as of that date. As permitted, we have not retrospectively modified our consolidated financial statements for comparative purposes. The adoption of the standard had a material impact on our consolidated balance sheet, but did not have an impact on our consolidated statements of operations, comprehensive income or cash flows. As a result of adoption, we have recorded additional net right-of-use ("ROU") lease assets and lease liabilities of approximately $888 million and $888 million, respectively, as of January 1, 2019. In addition, we have updated our business processes, systems, and internal controls to support the on-going reporting requirements under the new standard.

To adopt Topic 842, the Partnership elected the package of practical expedients permitted under the transition guidance within the standard. The expedient package allowed us not to reassess whether existing contracts contained a lease, the lease classification of existing leases and initial direct cost for existing leases. In addition to the package of practical expedients, the Partnership has elected not to capitalize amounts pertaining to leases with terms less than twelve months, to use the portfolio approach to determine discount rates, not to separate non-lease components from lease components and not to apply the use of hindsight to the active lease population.

Cumulative-effect adjustments made to the opening balance sheet at January 1, 2019 were as follows:

	Balance at December 31, 2018, as previously reported	Adjustments due to Topic 842 (Leases)	Balance at January 1, 2019
Assets:			
Property, plant and equipment, net	$ 66,655	$ (1)	$ 66,654
Lease right-of-use assets, net	—	889	889
Liabilities:			
Operating lease current liabilities	$ —	$ 71	$ 71
Accrued and other current liabilities	2,847	(1)	2,846
Current maturities of long-term debt	2,655	1	2,656
Long-term debt, less current maturities	37,853	6	37,859
Non-current operating lease liabilities	—	823	823
Other non-current liabilities	1,184	(12)	1,172

Additional disclosures related to lease accounting are included in Note 12.

Regulatory Accounting – Regulatory Assets and Liabilities

Our interstate transportation and storage segment is subject to regulation by certain state and federal authorities, and certain subsidiaries in that segment have accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of our regulated entities to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for these entities, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978, it does not currently apply regulatory accounting policies in accounting for its operations. Panhandle does not apply regulatory accounting policies primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

The net change in operating assets and liabilities (net of effects of acquisitions) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31,		
	2019	2018	2017
Accounts receivable	$ (473)	$ 506	$ (951)
Accounts receivable from related companies	(17)	128	(462)
Inventories	(20)	237	183
Other current assets	107	7	40
Other non-current assets, net	(155)	(119)	(162)
Accounts payable	148	(769)	713
Accounts payable to related companies	(92)	(206)	486
Accrued and other current liabilities	23	365	(56)
Other non-current liabilities	(187)	(34)	78
Price risk management assets and liabilities, net	218	(53)	9
Net change in operating assets and liabilities, net of effects of acquisitions	$ (448)	$ 62	$ (122)

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Years Ended December 31,		
	2019	2018	2017
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 1,334	$ 1,030	$ 1,060
Lease assets obtained in exchange for new lease liabilities	68	—	—
Net gains (losses) from subsidiary common unit transactions	—	(127)	5
NON-CASH FINANCING ACTIVITIES:			
Contribution of assets from noncontrolling interests	$ —	$ —	$ 988
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 1,799	$ 1,537	$ 1,516
Cash paid for income taxes	30	508	50

Accounts Receivable

Our operations deal with a variety of counterparties across the energy sector, some of which are investment grade, and most of which are not. Internal credit ratings and credit limits are assigned to all counterparties and limits are monitored against credit exposure. Letters of credit or prepayments may be required from those counterparties that are not investment grade depending on the internal credit rating and level of commercial activity with the counterparty.

We have a diverse portfolio of customers; however, because of the midstream and transportation services we provide, many of our customers are engaged in the exploration and production segment. We manage trade credit risk to mitigate credit losses and exposure to uncollectible trade receivables. Prospective and existing customers are reviewed regularly for creditworthiness to manage credit risk within approved tolerances. Customers that do not meet minimum credit standards are required to provide additional credit support in the form of a letter of credit, prepayment, or other forms of security. We establish an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables and consider many factors including historical customer collection experience, general and specific economic trends, and known specific issues related to individual customers, sectors, and transactions that might impact collectability. Increases in the allowance are recorded as a component of operating expenses; reductions in the allowance are recorded when receivables are subsequently collected or written-off. Past due receivable balances are written-off when our efforts have been unsuccessful in collecting the amount due.

Inventories

Inventories consist principally of natural gas held in storage, NGLs and refined products, crude oil and spare parts, all of which are valued at the lower of cost or net realizable value utilizing the weighted-average cost method.

Inventories consisted of the following:

	December 31,	
	2019	2018
Natural gas, NGLs and refined products [1]	$ 833	$ 833
Crude oil	251	201
Spare parts and other	448	338
Total inventories	$ 1,532	$ 1,372

(1) Due to changes in fuel prices, Sunoco LP recorded a write-down on the value of its fuel inventory of $85 million as of December 31, 2018.

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. Changes in fair value of designated hedged inventory are recorded in inventory on our consolidated balance sheets and cost of products sold in our consolidated statements of operations.

Other Current Assets

Other current assets consisted of the following:

	December 31, 2019	December 31, 2018
Deposits paid to vendors	$ 95	$ 141
Prepaid expenses and other	196	215
Total other current assets	$ 291	$ 356

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or FERC-mandated lives of the assets, if applicable. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our consolidated statements of operations.

Property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value.

In 2019, USAC recognized a $6 million fixed asset impairment related to certain idle compressor assets. Sunoco LP recognized a $47 million write-down on assets held for sale related to its ethanol plant in Fulton, New York.

In 2018, USAC recognized a $9 million fixed asset impairment related to certain idle compressor assets.

In 2017, the Partnership recorded a $127 million fixed asset impairment related to Sea Robin primarily due to a reduction in expected future cash flows due to an increase during 2017 in insurance costs related to offshore assets.

Capitalized interest is included for pipeline construction projects, except for certain interstate projects for which an allowance for funds used during construction (“AFUDC”) is accrued. Interest is capitalized based on the current borrowing rate of our revolving credit facilities when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31, 2019	December 31, 2018
Land and improvements	$ 1,232	$ 1,168
Buildings and improvements (1 to 45 years)	2,631	2,636
Pipelines and equipment (5 to 83 years)	64,678	58,783
Product storage and related facilities and equipment (2 to 83 years)	5,898	4,978
Right of way (20 to 83 years)	4,851	4,533
Other (1 to 48 years)	1,509	1,115
Construction work-in-process	8,495	6,067
Property, plant and equipment, gross	89,294	79,280
Less: Accumulated depreciation and depletion	(15,398)	(12,625)
Property, plant and equipment, net	$ 73,896	$ 66,655

We recognized the following amounts for the periods presented:

	Years Ended December 31,		
	2019	2018	2017
Depreciation, depletion and amortization expense	$ 2,828	$ 2,522	$ 2,199
Capitalized interest	166	294	286

Advances to and Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee’s operating and financial policies. An impairment of an investment in an unconsolidated affiliate is recognized when circumstances indicate that a decline in the investment value is other than temporary.

Other Non-Current Assets, net

Other non-current assets, net are stated at cost less accumulated amortization. Other non-current assets, net consisted of the following:

	December 31,	
	2019	2018
Crude pipeline linefill and tank bottoms	$ 496	$ 472
Regulatory assets	42	43
Pension assets	84	68
Deferred charges	178	178
Restricted funds	178	178
Other	593	539
Total other non-current assets, net	$ 1,571	$ 1,478

Restricted funds includes an immaterial amount of restricted cash primarily held in our wholly-owned captive insurance companies.

Intangible Assets

Intangible assets are stated at cost, net of amortization computed on the straight-line method. The Partnership removes the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized.

Components and useful lives of intangible assets were as follows:

	December 31, 2019		December 31, 2018	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 7,535	$ (1,743)	$ 7,106	$ (1,493)
Patents (10 years)	48	(35)	48	(30)
Trade Names (20 years)	66	(31)	66	(28)
Other (5 to 20 years)	19	(12)	33	(9)
Total amortizable intangible assets	7,668	(1,821)	7,253	(1,560)
Non-amortizable intangible assets:				
Trademarks	295	—	295	—
Other	12	—	12	—
Total non-amortizable intangible assets	307	—	307	—
Total intangible assets	$ 7,975	$ (1,821)	$ 7,560	$ (1,560)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2019	2018	2017
Reported in depreciation, depletion and amortization expense	$ 308	$ 321	$ 336

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2020	$ 394
2021	390
2022	360
2023	320
2024	307

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate.

Sunoco LP performed impairment tests on its indefinite-lived intangible assets during the fourth quarter of 2018 and recognized a $30 million impairment charge on its contractual rights, included in other in the table above, primarily due to decreases in projected future revenues and cash flows from the date the intangible assets were originally recorded.

Sunoco LP performed impairment tests on its indefinite-lived intangible assets during the fourth quarter of 2017 and recognized a total of $17 million in impairment charges on their contractual rights and liquor licenses primarily due to decreases in projected future revenues and cash flows from the date the intangible assets were originally recorded.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. The annual impairment test is performed during the fourth quarter.

Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation and Storage	Midstream	NGL and Refined Products Transportation and Services	Crude Oil Transportation and Services	Investment in Sunoco LP	Investment in USAC	All Other	Total
Balance, December 31, 2017	$ 10	$ 196	$ 870	$ 693	$ 1,167	$ 1,430	$ —	$ 363	$ 4,729
Acquired	—	—	—	—	—	129	366	—	495
CDM Contribution	—	—	—	—	—	—	253	(253)	—
Impaired	—	—	(378)	—	—	—	—	—	(378)
Other	—	—	—	—	—	—	—	39	39
Balance, December 31, 2018	10	196	492	693	1,167	1,559	619	149	4,885
Acquired	—	42	—	—	230	—	—	35	307
Impaired	—	(12)	(9)	—	—	—	—	—	(21)
Other	—	—	—	—	—	(4)	—	—	(4)
Balance, December 31, 2019	$ 10	$ 226	$ 483	$ 693	$ 1,397	$ 1,555	$ 619	$ 184	$ 5,167

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized. During the fourth quarter of 2019, $265 million goodwill was recorded in conjunction with the acquisition of SemGroup.

During the third quarter of 2019, the Partnership recognized a goodwill impairment of $12 million related to the Southwest Gas operations within the interstate segment primarily due to decreases in projected future revenues and cash flows. During the fourth quarter of 2019, the Partnership recognized a goodwill impairment of $9 million related to our North Central operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows.

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 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. Sunoco LP recognized goodwill impairments of $387 million, 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.

In connection with aforementioned impairments, the Partnership determined the fair value of our reporting units using a weighted combination of the discounted cash flow method and the guideline company method. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Such estimates and assumptions include revenue growth rates, operating margins, weighted average costs of capital and future market conditions, among others. The Partnership believes the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. Under the discounted cash flow method, the Partnership determined fair value based on estimated future cash flows of each reporting unit including estimates for capital expenditures, discounted to present value using the risk-adjusted industry rate, which reflect the overall level of inherent risk of the reporting unit. Cash flow projections are derived from one year budgeted amounts and five year operating forecasts plus an estimate of later period cash flows, all of which are evaluated by management. Subsequent period cash flows are developed for each reporting unit using growth rates that management believes are reasonably likely to occur. Under the guideline company method, the Partnership determined the estimated fair value of each of our reporting units by applying valuation multiples of comparable publicly-traded companies to each reporting unit's projected EBITDA and then averaging that estimate with similar historical calculations using a three year average. In addition, the Partnership estimated a reasonable control premium representing the incremental value that accrues to the majority owner from the opportunity to dictate the strategic and operational actions of the business.

During the first quarter of 2020, due to the impacts of the COVID-19 pandemic, the decline in commodity prices and the decreases in the Partnership's market capitalization, we determined that interim impairment testing should be performed on certain reporting units. We performed the interim impairment tests consistent with our approach for annual impairment testing, including using similar models, inputs and assumptions. As a result of the interim impairment test, the Partnership recognized a goodwill impairment of $483 million related to our Arklatex and South Texas operations within the midstream segment, a goodwill impairment of $183 million related to our Lake Charles LNG regasification operations within the interstate transportation and storage segment due to contractually scheduled reductions in payments for the remainder of the contract term, and a goodwill impairment of $40 million related to our all other operations primarily due to decreases in projected future revenues and cash flows as a result of the overall market demand decline. In addition, USAC recognized a goodwill impairment of $619 million during the three months ended March 31, 2020.

In the third quarter of 2020, the Partnership performed interim impairment testing on certain reporting units within its midstream, interstate, crude, NGL and all other operations. As a result, the Partnership recognized a goodwill impairment of $1.28 billion related to our crude operations, a goodwill impairment of $132 million related to our SemCAMS operations within the all other segment, which included approximately $97 million of goodwill allocated to SemCAMS operations when the acquisition accounting was finalized during 2020, and a goodwill impairment of $43 million related to our interstate operations primarily due to decreases in projected future cash flow as a result of the overall market demand decline. No other impairments of the Partnership's goodwill were identified.

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 ARO 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 AROs as of December 31, 2019 and 2018, 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. ETC Sunoco 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, ETC Sunoco is legally or contractually required to abandon in place or remove the asset. We believe we may have additional AROs related to ETC Sunoco'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.

As of December 31, 2019 and 2018, other non-current liabilities in the Partnership's consolidated balance sheets included AROs of $247 million and $193 million, respectively. For the years ended December 31, 2019, 2018 and 2017 aggregate accretion expense related to AROs was $5 million, $13 million and $9 million, respectively.

Individual component assets have been and will continue to be replaced, but the pipeline and the natural gas gathering and processing systems will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities, management expects supply and demand to exist for the foreseeable future. We have in place a rigorous repair and maintenance program that keeps the pipelines and the natural gas gathering and processing systems in good working order. Therefore, although some of the individual assets may be replaced, the pipelines and the natural gas gathering and processing systems themselves will remain intact indefinitely.

Oher non-current assets on the Partnership's consolidated balance sheet included $31 million and $26 million of legally restricted funds for the purpose of settling AROs as of December 31, 2019 and 2018, respectively.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2019	2018
Interest payable	$ 576	$ 503
Customer advances and deposits	123	128
Accrued capital expenditures	1,334	1,030
Accrued wages and benefits	217	283
Taxes payable other than income taxes	263	256
Exchanges payable	67	112
Other	756	535
Total accrued and other current liabilities	$ 3,336	$ 2,847

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month. Prepayments and security deposits may be required when customers exceed their credit limits or do not qualify for open credit.

Redeemable Noncontrolling Interests

Our redeemable noncontrolling interests relate to certain preferred unitholders of one of our consolidated subsidiaries that have the option to convert their preferred units to such subsidiary’s common units at the election of the holders and the noncontrolling interest holders in one of our consolidated subsidiaries that have the option to sell their interests to us. In accordance with applicable accounting guidance, the noncontrolling interest is excluded from total equity and reflected as redeemable noncontrolling interests on our consolidated balance sheet. See Note 6 for further information.

Environmental Remediation

We accrue environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. Such accruals are undiscounted and are based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. If a range of probable environmental cleanup costs exists for an identified site, the minimum of the range is accrued unless some other point in the range is more likely in which case the most likely amount in the range is accrued.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2019 was $54.66 billion and$50.93 billion , respectively. As of December 31, 2018, the aggregate fair value and carrying amount of our debt obligations was $39.54 billion and $40.51 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

We have commodity derivatives, interest rate derivatives and embedded derivatives in our preferred units that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “level” of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. During the year ended December 31, 2019, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of December 31, 2019 and 2018 based on inputs used to derive their fair values:

		Fair Value Measurements at December 31, 2019	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 17	$ 17	$ —
Swing Swaps IFERC	1	—	1
Fixed Swaps/Futures	65	65	—
Forward Physical Contracts	3	—	3
Power:			
Forwards	11	—	11
Futures	4	4	—
Options – Puts	1	1	—
Options – Calls	1	1	—
NGLs – Forwards/Swaps	260	260	—
Refined Products – Futures	8	8	—
Crude – Forwards/Swaps	13	13	—
Total commodity derivatives	384	369	15
Other non-current assets	31	20	11
Total assets	$ 415	$ 389	$ 26
Liabilities:			
Interest rate derivatives	$ (399)	$ —	$ (399)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(49)	(49)	—
Swing Swaps IFERC	(1)	—	(1)
Fixed Swaps/Futures	(43)	(43)	—
Power:			
Forwards	(5)	—	(5)
Futures	(3)	(3)	—
NGLs – Forwards/Swaps	(278)	(278)	—
Refined Products – Futures	(10)	(10)	—
Total commodity derivatives	(389)	(383)	(6)
Total liabilities	$ (788)	$ (383)	$ (405)

		Fair Value Measurements at December 31, 2018	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 42	$ 42	$ —
Swing Swaps IFERC	52	8	44
Fixed Swaps/Futures	97	97	—
Forward Physical Contracts	20	—	20
Power:			
Power – Forwards	48	—	48
Futures	1	1	—
Options – Calls	1	1	—
NGLs – Forwards/Swaps	291	291	—
Refined Products – Futures	7	7	—
Crude - Forwards/Swaps	1	1	—
Total commodity derivatives	560	448	112
Other non-current assets	26	17	9
Total assets	$ 586	$ 465	$ 121
Liabilities:			
Interest rate derivatives	$ (163)	$ —	$ (163)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(91)	(91)	—
Swing Swaps IFERC	(40)	—	(40)
Fixed Swaps/Futures	(88)	(88)	—
Forward Physical Contracts	(21)	—	(21)
Power:			
Forwards	(42)	—	(42)
Futures	(1)	(1)	—
NGLs – Forwards/Swaps	(224)	(224)	—
Refined Products – Futures	(15)	(15)	—
Crude - Forwards/Swaps	(61)	(61)	—
Total commodity derivatives	(583)	(480)	(103)
Total liabilities	$ (746)	$ (480)	$ (266)

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs (“CIAC”) are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized.

Shipping and Handling Costs

Shipping and handling costs are included in cost of products sold, except for shipping and handling costs related to fuel consumed for compression and treating which are included in operating expenses.

Costs and Expenses

Cost of products sold include actual cost of fuel sold, adjusted for the effects of our hedging and other commodity derivative activities, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, purchasing costs and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis except for our all other segment in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and costs and expenses in the consolidated statements of operations, with no effect on net income. For the years ended December 31, 2019, 2018 and 2017, excise taxes collected by Sunoco LP were $386 million, $370 million and $234 million, respectively.

Issuances of Subsidiary Units

We record changes in our ownership interest of our subsidiaries as equity transactions, with no gain or loss recognized in consolidated net income or comprehensive income. For example, upon our subsidiary's issuance of common units in a public offering, we record any difference between the amount of consideration received or paid and the amount by which the noncontrolling interests are adjusted as a change in partners' capital.

Income Taxes

ETO is a publicly traded limited partnership and is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and most state purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to our preferred unitholders as a result of differences between the tax basis and financial basis of assets and liabilities, differences between the tax accounting and financial accounting treatment of certain items, and due to allocation requirements related to taxable income under our Fifth Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement").

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and Internal Revenue Service ("IRS") pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, ETO would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2019, 2018 and 2017, our qualifying income met the statutory requirement.

The Partnership conducts certain activities through corporate subsidiaries which are subject to federal, state and local income taxes. These corporate subsidiaries include ETP Holdco, Inland Corporation, Sunoco Property Company LLC and Aloha. The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third-party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a commodity hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statements of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statements of operations.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, the change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in "Gains (losses) on interest rate derivatives" in the consolidated statements of operations.

In August 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*. The amendments in this update improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. In addition, the amendments in this update make certain targeted improvements to simplify the application of the hedge accounting guidance in current GAAP. The Partnership adopted the new rules in the first quarter of 2019, and the adoption of the new accounting rules did not have a material impact on the consolidated financial statements and related disclosures.

Non-Cash Compensation

For awards of restricted units, we recognize compensation expense over the vesting period based on the grant-date fair value, which is determined based on the market price of the underlying common units on the grant date. For awards of cash restricted units, we remeasure the fair value of the award at the end of each reporting period based on the market price of the underlying common units as of the reporting date, and the fair value is recorded in other non-current liabilities on our consolidated balance sheets.

Pensions and Other Postretirement Benefit Plans

The Partnership recognizes the overfunded or underfunded status of defined benefit pension and other postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Changes in the funded status of the plan are recorded in the year in which the change occurs within AOCI in equity or, for entities applying regulatory accounting, as a regulatory asset or regulatory liability.

Allocation of Income

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests. The capital account provisions of our Partnership Agreement incorporate principles established for United States Federal income tax purposes and may not be comparable to the partners' capital balances reflected under GAAP in our consolidated financial statements. Subsequent to the Energy Transfer Merger, our general partner owns a non-economic interest in us and, therefore, our net income for partners' capital and statement of operations presentation purposes is allocated entirely to the Limited Partners.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2019 and 2020 Transactions

SemGroup Acquisition

In December 2019, ET completed the acquisition of SemGroup. ET contributed SemGroup and its former subsidiaries to ETO through sale and contribution transactions in 2020. The contribution transactions were accounted for as reorganizations of entities under common control; therefore, the contributed entities' assets and liabilities were not adjusted as of the contribution date. The Partnership's consolidated financial statements have been retrospectively adjusted to reflect consolidation of SemGroup beginning in December 2019. Predecessor equity included in the consolidated financial statements for 2019 represents the SemGroup assets based on ET's carrying value for the period prior to the contribution to ETO.

The following table represents the fair value, as of December 5, 2019, of the SemGroup assets and liabilities transferred from ET to ETO:

	At December 5, 2019
Total current assets	$ 794
Property, plant and equipment	3,914
Other non-current assets	623
Goodwill [1]	265
Intangible assets	460
Total assets	6,056
Total current liabilities	629
Long-term debt, less current maturities [2]	2,576
Other non-current liabilities	196
SemCAMS Preferred shares	241
Total liabilities	3,642
Noncontrolling interest	822
Total consideration [3]	1,592
Cash received [4]	153
Total consideration, net of cash received	$ 1,439

[1] None of the goodwill is expected to be deductible for tax purposes. Goodwill recognized from the business combination primarily relates to the value attributed to additional growth opportunities, synergies and operating leverage within SemGroup's operations. During 2020, the Partnership adjusted the purchase price allocation of goodwill from the acquisition of SemGroup which resulted in an increase of goodwill of $30 million along with the a corresponding decrease in deferred tax liabilities.

[2] Long-term debt at December 5, 2019 includes SemGroup senior notes with an aggregate principal amount of $1.375 billion and SemGroup subsidiary debt of $593 million, all of which was redeemed in December 2019, subsequent to the close of the SemGroup Transaction.

[3] Total consideration includes (i) cash paid to SemGroup shareholders, (ii) fair value of ET Common Units issued in the acquisition and (iii) cash paid to redeem SemGroup's preferred shares.

[4] Cash received represents cash and cash equivalents held by SemGroup as of the acquisition date.

Subsequent to December 31, 2019, the Partnership has recorded impairments on certain of the contributed SemGroup assets. Those impairments include a $244 million impairment of goodwill and a $129 million impairment of other non-current assets.

2018 Transactions

ET Contribution of Assets to ETO

Immediately prior to the closing of the Energy Transfer Merger discussed in Note 1, 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 to ETO in exchange for 37,557,815 ETO common units.

USAC Acquisition

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 IDRs 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 newly authorized and established 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 are a new class of partnership interests of USAC that 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.

As noted above, ET contributed its interests in USAC to ETO in October 2018. ET's contribution of its interests in USAC was a transaction between entities under common control; therefore, the Partnership's consolidated financial statements reflect USAC on a consolidated basis beginning April 2, 2018, the date that ET obtained control of USAC. The Partnership had previously deconsolidated CDM upon its contribution to USAC on April 2, 2018; however, due to the retrospective consolidation of USAC as of that date, CDM is reflected as a consolidated subsidiary for all periods presented herein.

Summary of Assets Acquired and Liabilities Assumed

The USAC Transaction was recorded using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date.

The total purchase price was allocated as follows:

	At April 2, 2018
Total current assets	$ 786
Property, plant and equipment	1,332
Other non-current assets	15
Goodwill[(1)]	366
Intangible assets	222
Total assets	2,721
Total current liabilities	110
Long-term debt, less current maturities	1,527
Other non-current liabilities	2
Total liabilities	1,639
Noncontrolling interest	832
Total consideration	250
Cash received[(2)]	711
Total consideration, net of cash received[(2)]	$ (461)

(1) None of the goodwill is expected to be deductible for tax purposes. Goodwill recognized from the business combination primarily relates to the value attributed to additional growth opportunities, synergies and operating leverage within USAC's operations.

(2) Cash received represents cash and cash equivalents held by USAC as of the acquisition date.

The fair values of the assets acquired and liabilities assumed were determined using various valuation techniques, including the income and market approaches.

Sunoco LP Retail Store Divestment

On January 23, 2018, Sunoco LP completed the disposition of assets pursuant to the purchase agreement with 7-Eleven, Inc. (the "7-Eleven Transaction"). As a result of the 7-Eleven Transaction, previously eliminated wholesale motor fuel sales to Sunoco LP's retail locations are reported as wholesale motor fuel sales to third parties. Also, the related accounts receivable from such sales are no longer eliminated from the Partnership's consolidated balance sheets and are reported as accounts receivable.

In connection with the 7-Eleven Transaction, Sunoco LP entered into a Distributor Motor Fuel Agreement dated as of January 23, 2018 ("Supply Agreement"), with 7-Eleven and SEI Fuel (collectively, "Distributor"). The Supply Agreement consists of a 15-year take-or-pay fuel supply arrangement under which Sunoco LP has agreed to supply approximately 2.0 billion gallons of fuel annually plus additional aggregate growth volumes of up to 500 million gallons to be added incrementally over the first four years. For the period from January 1, 2018 through January 22, 2018 and the years ended December 31, 2017, Sunoco LP recorded sales to the sites that were subsequently sold to 7-Eleven of $199 million and $3.2 billion, respectively, which were eliminated in consolidation. Sunoco LP received payments on trade receivables of $3.7 billion and $3.4 billion, respectively, from 7-Eleven for the years ended December 31, 2019 and December 31, 2018 subsequent to the closing of the sale.

The Partnership has concluded that it meets the accounting requirements for reporting the financial position, results of operations and cash flows of Sunoco LP's retail divestment as discontinued operations.

There were no results of operations associated with discontinued operations for the year ended December 31, 2019. The results of operations associated with discontinued operations for the years ended December 31, 2018 and 2017 are presented in the following table:

	Years Ended December 31,	
	2018	2017
REVENUES	$ 349	$ 6,964
COSTS AND EXPENSES		
Cost of products sold	305	5,806
Operating expenses	61	763
Depreciation, depletion and amortization	—	34
Selling, general and administrative	7	168
Impairment losses	—	285
Total costs and expenses	373	7,056
OPERATING LOSS	(24)	(92)
OTHER EXPENSE		
Interest expense, net	2	36
Loss on extinguishment of debt	20	—
Other, net	61	1
LOSS FROM DISCONTINUED OPERATIONS BEFORE INCOME TAX EXPENSE	(107)	(129)
Income tax expense	158	48
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	$ (265)	$ (177)

2017 Transactions

Rover Contribution Agreement

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

ETO and Sunoco Logistics Merger

As discussed in Note 1, in April 2017, Energy Transfer Partners, L.P. and Sunoco Logistics completed the Sunoco Logistics Merger.

Permian Express Partners

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

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

Bakken Equity Sale

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

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Citrus

We own CrossCountry Energy, LLC, a wholly-owned subsidiary of ETO, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of KMI. Citrus owns 100% of FGT, an approximately 5,362-mile natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula. Our investment in Citrus is reflected in our interstate transportation and storage segment.

FEP

We have a 50% interest in FEP which owns an approximately 185-mile natural gas pipeline that originates in Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline in Panola County, Mississippi. Our investment in FEP is reflected in the interstate transportation and storage segment. The Partnership evaluated its investment in FEP for impairment as of December 31, 2017, based on FASB Accounting Standards Codification 323, *Investments - Equity Method and Joint Ventures*. The Partnership recorded an impairment of its investment in FEP of $141 million during the year ended December 31, 2017 due to a negative outlook for long-term transportation contracts as a result of a decrease in production in the Fayetteville basin and a customer re-contracting with a competitor. Subsequent to December 31, 2019, FEP recorded impairments of property, plant and equipment which have reduced our carrying value of this investment to near zero resulting from decreases in projected future cash flow as a result of the overall market demand decline.

MEP

We own a 50% interest in MEP, which owns approximately 500 miles of natural gas pipeline that extends from Southeast Oklahoma, across Northeast Texas, Northern Louisiana and Central Mississippi to an interconnect with the Transcontinental natural gas pipeline system in Butler, Alabama. Our investment in MEP is reflected in the interstate transportation and storage segment.

The carrying value of the Partnership’s advances to and investments in unconsolidated affiliates as of December 31, 2019 and 2018 were as follows:

	December 31,	
	2019	2018
Citrus	$ 1,876	$ 1,737
FEP	218	107
MEP	429	225
Others	931	567
Total	$ 3,454	$ 2,636

The following table presents equity in earnings (losses) of unconsolidated affiliates:

	Years Ended December 31,		
	2019	2018	2017
Citrus	$ 148	$ 141	$ 144
FEP	59	55	53
MEP	15	31	38
Other	80	117	(91)
Total equity in earnings of unconsolidated affiliates	$ 302	$ 344	$ 144

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, Citrus, FEP and MEP (on a 100% basis) for all periods presented, except as noted below:

	December 31,	
	2019	2018
Current assets	$ 247	$ 212
Property, plant and equipment, net	7,680	7,800
Other assets	40	39
Total assets	$ 7,967	$ 8,051
Current liabilities	$ 738	$ 1,534
Non-current liabilities	3,242	3,439
Equity	3,987	3,078
Total liabilities and equity	$ 7,967	$ 8,051

	Years Ended December 31,		
	2019	2018	2017
Revenue	$ 1,192	$ 1,249	$ 1,358
Operating income	683	723	407
Net income	443	460	145

In addition to the equity method investments described above we have other equity method investments which are not significant to our consolidated financial statements.

5. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2019	2018
ETO Debt		
9.70% Senior Notes due March 15, 2019	$ —	$ 400
9.00% Senior Notes due April 15, 2019	—	450
5.50% Senior Notes due February 15, 2020 (1)	250	250
5.75% Senior Notes due September 1, 2020 (1)	400	400
4.15% Senior Notes due October 1, 2020 (1)	1,050	1,050
7.50% Senior Notes due October 15, 2020 (1)	1,135	—

4.40% Senior Notes due April 1, 2021	600	600
4.65% Senior Notes due June 1, 2021	800	800
5.20% Senior Notes due February 1, 2022	1,000	1,000
4.65% Senior Notes due February 15, 2022	300	300
5.875% Senior Notes due March 1, 2022	900	900
5.00% Senior Notes due October 1, 2022	700	700
3.45% Senior Notes due January 15, 2023	350	350
3.60% Senior Notes due February 1, 2023	800	800
4.25% Senior Notes due March 15, 2023	995	—
4.20% Senior Notes due September 15, 2023	500	500
4.50% Senior Notes due November 1, 2023	600	600
5.875% Senior Notes due January 15, 2024	1,127	—
4.90% Senior Notes due February 1, 2024	350	350
7.60% Senior Notes due February 1, 2024	277	277
4.25% Senior Notes due April 1, 2024	500	500
4.50% Senior Notes due April 15, 2024	750	—
9.00% Debentures due November 1, 2024	65	65
4.05% Senior Notes due March 15, 2025	1,000	1,000
5.95% Senior Notes due December 1, 2025	400	400
4.75% Senior Notes due January 15, 2026	1,000	1,000
3.90% Senior Notes due July 15, 2026	550	550
4.20% Senior Notes due April 15, 2027	600	600
5.50% Senior Notes due June 1, 2027	956	—
4.00% Senior Notes due October 1, 2027	750	750
4.95% Senior Notes due June 15, 2028	1,000	1,000
5.25% Senior Notes due April 15, 2029	1,500	—
8.25% Senior Notes due November 15, 2029	267	267
4.90% Senior Notes due March 15, 2035	500	500
6.625% Senior Notes due October 15, 2036	400	400
5.80% Senior Notes due June 15, 2038	500	500
7.50% Senior Notes due July 1, 2038	550	550
6.85% Senior Notes due February 15, 2040	250	250
6.05% Senior Notes due June 1, 2041	700	700
6.50% Senior Notes due February 1, 2042	1,000	1,000
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	350
5.15% Senior Notes due February 1, 2043	450	450
5.95% Senior Notes due October 1, 2043	450	450
5.30% Senior Notes due April 1, 2044	700	700
5.15% Senior Notes due March 15, 2045	1,000	1,000
5.35% Senior Notes due May 15, 2045	800	800
6.125% Senior Notes due December 15, 2045	1,000	1,000
5.30% Senior Notes due April 15, 2047	900	900
5.40% Senior Notes due October 1, 2047	1,500	1,500
6.00% Senior Notes due June 15, 2048	1,000	1,000
6.25% Senior Notes due April 15, 2049	1,750	—
Floating Rate Junior Subordinated Notes due November 1, 2066	546	546
ETO $2.00 billion Term Loan facility due October 2022	2,000	—
ETO $5.00 billion Revolving Credit Facility due December 2023	4,214	3,694
Unamortized premiums, discounts and fair value adjustments, net	(5)	17
Deferred debt issuance costs	(207)	(178)
	42,120	32,288
Transwestern Debt		
5.36% Senior Notes due December 9, 2020 (1)	175	175
5.89% Senior Notes due May 24, 2022	150	150
5.66% Senior Notes due December 9, 2024	175	175
6.16% Senior Notes due May 24, 2037	75	75
Deferred debt issuance costs	(1)	(1)

	574	574
Panhandle Debt		
8.125% Senior Notes due June 1, 2019	—	150
7.60% Senior Notes due February 1, 2024	82	82
7.00% Senior Notes due July 15, 2029	66	66
8.25% Senior Notes due November 15, 2029	33	33
Floating Rate Junior Subordinated Notes due November 1, 2066	54	54
Unamortized premiums, discounts and fair value adjustments, net	11	14
	246	399
Bakken Project Debt		
3.625% Senior Notes due April 1, 2022	650	—
3.90% Senior Notes due April 1, 2024	1,000	—
4.625% Senior Notes due April 1, 2029	850	—
Bakken $2.50 billion Credit Facility due August 2019	—	2,500
Unamortized premiums, discounts and fair value adjustments, net	(3)	—
Deferred debt issuance costs	(16)	(3)
	2,481	2,497
Sunoco LP Debt		
4.875% Senior Notes Due January 15, 2023	1,000	1,000
5.50% Senior Notes Due February 15, 2026	800	800
6.00% Senior Notes Due April 15, 2027	600	—
5.875% Senior Notes Due March 15, 2028	400	400
Sunoco LP $1.50 billion Revolving Credit Facility due July 2023	162	700
Lease-related obligations	135	107
Deferred debt issuance costs	(26)	(23)
	3,071	2,984
USAC Debt		
6.875% Senior Notes due April 1, 2026	725	725
6.875% Senior Notes due September 1, 2027	750	—
USAC $1.60 billion Revolving Credit Facility due April 2023	403	1,050
Deferred debt issuance costs	(26)	(16)
	1,852	1,759
SemGroup Debt		
HFOTCO Tax Exempt Notes due 2050	225	—
SemCAMS Revolver due February 2024	92	—
SemCAMS Term Loan A due February 2024	269	—
Unamortized premiums, discounts and fair value adjustments, net	1	—
Deferred debt issuance costs	(3)	—
	584	—
Other	2	7
Total debt	50,930	40,508
Less: Current maturities of long-term debt	26	2,655
Long-term debt, less current maturities	$ 50,904	$ 37,853

(1) As of December 31, 2019, these notes were classified as long-term as management had the intent and ability to refinance the borrowings on a long-term basis. The notes were redeemed in January 2020.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $273 million in unamortized net premiums, fair value adjustments and deferred debt issuance costs:

2020	$	3,034
2021		1,412
2022		5,792
2023		8,960
2024		4,685
Thereafter		27,322
Total	$	51,205

Long-term debt reflected on our consolidated balance sheets includes fair value adjustments related to interest rate swaps, which represent fair value adjustments that had been recorded in connection with fair value hedge accounting prior to the termination of the interest rate swap.

ETO Senior Notes

The ETO senior notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETO senior notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETO senior notes. The balance is payable upon maturity. Interest on the ETO senior notes is paid semi-annually.

The ETO senior notes are unsecured obligations of the Partnership and as a result, the ETO senior notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETO senior notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

ETO January 2020 Senior Notes Offering and Redemption

On January 22, 2020, ETO completed a registered offering (the “January 2020 Senior Notes Offering”) of $1.00 billion aggregate principal amount of the Partnership’s 2.900% Senior Notes due 2025, $1.50 billion aggregate principal amount of the Partnership’s 3.750% Senior Notes due 2030 and $2.00 billion aggregate principal amount of the Partnership’s 5.000% Senior Notes due 2050, (collectively, the “Notes”). The Notes are fully and unconditionally guaranteed by the Partnership’s wholly owned subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis.

Utilizing proceeds from the January 2020 Senior Notes Offering, ETO redeemed its $400 million aggregate principal amount of 5.75% Senior Notes due September 1, 2020, its $1.05 billion aggregate principal amount of 4.15% Senior Notes due October 1, 2020, its $1.14 billion aggregate principal amount of 7.50% Senior Notes due October 15, 2020, its $250 million aggregate principal amount of 5.50% Senior Notes due February 15, 2020, ET’s $52 million aggregate principal amount of 7.50% Senior Notes due October 15, 2020 and Transwestern’s $175 million aggregate principal amount of 5.36% Senior Notes due December 9, 2020.

ET-ETO Senior Notes Exchange

In February 2019, ETO commenced offers to exchange all of ET’s outstanding senior notes for senior notes issued by ETO (the “ET-ETO senior notes exchange”). Approximately 97% of ET’s outstanding senior notes were tendered and accepted, and substantially all the exchanges settled on March 25, 2019. In connection with the exchange, ETO issued approximately $4.21 billion aggregate principal amount of the following senior notes:

- $1.14 billion aggregate principal amount of 7.50% senior notes due 2020;
- $995 million aggregate principal amount of 4.25% senior notes due 2023;
- $1.13 billion aggregate principal amount of 5.875% senior notes due 2024; and
- $956 million aggregate principal amount of 5.50% senior notes due 2027.

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.

Panhandle Senior Notes Redemption

In June 2019, Panhandle’s $150 million aggregate principal amount of 8.125% senior notes matured and were repaid with borrowings under an affiliate loan agreement with ETO.

Bakken Senior Notes Offering

In March 2019, Midwest Connector Capital Company LLC, a wholly-owned subsidiary of Dakota Access, issued the following senior notes related to the Bakken pipeline:

- $650 million aggregate principal amount of 3.625% senior notes due 2022;
- $1.00 billion aggregate principal amount of 3.90% senior notes due 2024; and
- $850 million aggregate principal amount of 4.625% senior notes due 2029.

The $2.48 billion in net proceeds from the offering were used to repay in full all amounts outstanding on the Bakken credit facility and the facility was terminated.

Sunoco LP Senior Notes Offering

In March 2019, Sunoco LP issued $600 million aggregate principal amount of 6.00% senior notes due 2027 in a private placement to eligible purchasers. The net proceeds from this offering were used to repay a portion of Sunoco LP’s existing borrowings under its credit facility. In July 2019, Sunoco LP completed an exchange of these notes for registered notes with substantially identical terms.

USAC Senior Notes Offering

In March 2019, USAC issued $750 million aggregate principal amount of 6.875% senior notes due 2027 in a private placement, and in December 2019, USAC exchanged those notes for substantially identical senior notes registered under the Securities Act. The net proceeds from this offering were used to repay a portion of USAC’s existing borrowings under its credit facility and for general partnership purposes.

Transwestern Senior Notes

The Transwestern senior notes are redeemable at any time in whole or pro rata, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is paid semi-annually.

Credit Facilities, Term Loan and Commercial Paper

ETO Term Loan

On October 17, 2019, ETO entered into a term loan credit agreement (the “ETO Term Loan”) providing for a $2.00 billion three-year term loan credit facility. Borrowings under the term loan agreement mature on October 17, 2022 and are available for working capital purposes and for general partnership purposes. The term loan agreement is unsecured and is guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P.

As of December 31, 2019, the ETO Term Loan had $2.00 billion outstanding and was fully drawn. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.78%.

ETO Five-Year Credit Facility

ETO's revolving credit facility (the "ETO Five-Year Credit Facility") allows for unsecured borrowings up to $5.00 billion and matures on 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, 2019, the ETO Five-Year Credit Facility had $4.21 billion outstanding, of which $1.64 billion was commercial paper. The amount available for future borrowings was $709 million after taking into account letters of credit of $77 million. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.88%.

ETO 364-Day Facility

ETO's 364-day revolving credit facility (the "ETO 364-Day Facility") allows for unsecured borrowings up to $1.00 billion and matures on November 27, 2020. As of December 31, 2019, the ETO 364-Day Facility had no outstanding borrowings.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.50 billion revolving credit facility (the "Sunoco LP Credit Facility"). As of December 31, 2019, the Sunoco LP Credit Facility had $162 million outstanding borrowings and $8 million in standby letters of credit. The amount available for future borrowings was $1.33 billion at December 31, 2019. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 3.75%.

USAC Credit Facility

USAC maintains a $1.60 billion revolving credit facility (the "USAC Credit Facility"), which matures on April 2, 2023 and permits up to $400 million of future increases in borrowing capacity. As of December 31, 2019, USAC had $403 million of outstanding borrowings and no outstanding letters of credit under the credit agreement. As of December 31, 2019, USAC had $1.2 billion of availability under its credit facility. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 4.31%.

SemCAMS Credit Facilities

SemCAMS is party to a credit agreement providing for a C$350 million (US$270 million at the December 31, 2019 exchange rate) senior secured term loan facility, a C$525 million (US$404 million at the December 31, 2019 exchange rate) senior secured revolving credit facility, and a C$300 million (US$231 million at the December 31, 2019 exchange rate) senior secured construction loan facility (the "KAPS Facility"). The term loan facility and the revolving credit facility mature on February 25, 2024. The KAPS Facility matures on June 13, 2024. SemCAMS may incur additional term loans and revolving commitments in an aggregate amount not to exceed C$250 million (US$193 million at the December 31, 2019 exchange rate), subject to receiving commitments for such additional term loans or revolving commitments from either new lenders or increased commitments from existing lenders.

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 contain 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 1.250% 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%.

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 4.04 to 1 at December 31, 2019, 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.

Panhandle's restrictive covenants include restrictions on liens securing debt and guarantees and restrictions on mergers and on the sales of assets. A breach of any of these covenants could result in acceleration of Panhandle's debt.

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) 5.5 to 1 through the end of the fiscal quarter ending December 31, 2019 and (ii) 5.0 to 1.0 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.

Covenants Related to the HFOTCO Tax Exempt Notes

The indentures covering HFOTCO's tax exempt notes due 2050 ("IKE Bonds") include customary representations and warranties and affirmative and negative covenants. Such covenants include limitations on the creation of new liens, indebtedness, making of certain restricted payments and payments on indebtedness, making certain dispositions, making material changes in business activities, making fundamental changes including liquidations, mergers or consolidations, making certain investments, entering into certain transactions with affiliates, making amendments to certain credit or organizational agreements, modifying the fiscal year, creating or dealing with hazardous materials in certain ways, entering into certain hedging arrangements, entering into certain restrictive agreements, funding or engaging in sanctioned activities, taking actions or causing the trustee to take actions that materially adversely affect the rights, interests, remedies or security of the bondholders, taking actions to remove the trustee, making certain amendments to the bond documents, and taking actions or omitting to take actions that adversely impact the tax exempt status of the IKE Bonds.

Compliance with our Covenants

We and our subsidiaries were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2019.

6. REDEEMABLE NONCONTROLLING INTERESTS

Certain redeemable noncontrolling interests in the Partnership’s subsidiaries are reflected as mezzanine equity on the consolidated balance sheet. Redeemable noncontrolling interests as of December 31, 2019 included a balance of $477 million related to the USAC Preferred Units described below and a balance of $15 million related to noncontrolling interest holders in one of the Partnership’s consolidated subsidiaries that have the option to sell their interests to the Partnership. In addition, redeemable noncontrolling interests includes a balance of $247 million in SemCAMS preferred shares acquired as part of the merger with SemGroup.

USAC Series A Preferred Units

In 2018, USAC issued 500,000 USAC Preferred Units in a private placement at a price of $1,000 per USAC Preferred Unit, for total gross proceeds of $500 million in a private placement.

The USAC Preferred Units are entitled to receive cumulative quarterly distributions equal to $24.375 per USAC Preferred Unit, subject to increase in certain limited circumstances. The USAC Preferred Units will have a perpetual term, unless converted or redeemed. Certain portions of the USAC Preferred Units will be convertible into USAC common units at the election of the holders beginning in 2021. To the extent the holders of the USAC Preferred Units have not elected to convert their preferred units by the fifth anniversary of the issue date, USAC will have the option to redeem all or any portion of the USAC Preferred Units for cash. In addition, at any time on or after the tenth anniversary of the issue date, the holders of the USAC Preferred Units will have the right to require USAC to redeem all or any portion of the USAC Preferred Units, and the Partnership may elect to pay up to 50% of such redemption amount in USAC common units.

SemCAMS Redeemable Preferred Stock

SemCAMS has 300,000 shares of cumulative preferred stock issued and outstanding. The preferred stock is redeemable at SemCAMS’s option subsequent to January 3, 2021 at a redemption price of C$1,100 (US$845 at the December 31, 2019 exchange rate) per share. The preferred stock is redeemable by the holder contingent upon a change of control or liquidation of SemCAMS. The preferred stock is convertible to SemCAMS common shares in the event of an initial public offering by SemCAMS.

The preferred stock was recorded at fair value in connection with the SemGroup purchase accounting. Dividends on the preferred stock are payable in-kind through the quarter ending June 30, 2020. The dividends paid-in-kind increased the liquidation preference such that as of December 31, 2019, the preferred stock was convertible into 315,859 shares.

7. EQUITY:

Limited Partner interests are represented by Common Units and other classes of units described below, as well as Series A Preferred Units, Series B Preferred Units, Series C Preferred Units, Series D Preferred Units, Series E Preferred Units, Series F Preferred Units, and Series G Preferred Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that ETP GP has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance.

Class K Units

As of December 31, 2019, a total of 101.5 million Class K Units were held by wholly-owned subsidiaries of ETO. Each Class K Unit is entitled to a quarterly cash distribution of $0.67275 per Class K Unit prior to ETO making distributions of available cash to any class of units, excluding any cash available distributions or dividends or capital stock sales proceeds received by ETO from ETP Holdco. If the Partnership is unable to pay the Class K Unit quarterly distribution with respect to any quarter, the accrued and unpaid distributions will accumulate until paid and any accumulated balance will accrue 1.5% per annum until paid.

Class L Units

On December 31, 2018, ETO issued a new class of limited partner interests titled Class L Units to two wholly-owned subsidiaries of the Partnership when the Partnership's previously outstanding Class E units and Class G units held by such subsidiaries were converted into Class L Units. As a result of the conversion, the Class E units and Class G units were cancelled.

The Class L Units generally do not have any voting rights. The Class L Units are entitled to aggregate cash distributions equal to 7.65% per annum of the total amount of cash generated by us and our subsidiaries, other than ETP Holdco, and available for distribution. Distributions shall be paid quarterly, in arrears, within 45 days after the end of each quarter. As the Class L Units are owned by a wholly-owned subsidiary, the cash distributions on those units are eliminated in our consolidated financial statements.

Class M Units

On July 1, 2019, ETO issued a new class of limited partner interests titled Class M Units to ETP Holdco, a wholly-owned subsidiary of the Partnership, in exchange for the contribution of ETP Holdco's equity ownership interest in Panhandle to the Partnership.

The Class M Units generally do not have any voting rights. The Class M Units are entitled to aggregate cash distributions equal to 8.00% per annum of the total amount of cash generated by us and our subsidiaries, other than ETP Holdco, and available for distribution. Distributions shall be paid quarterly, in arrears, within 45 days after the end of each quarter. As the Class M Units are owned by a wholly-owned subsidiary, the cash distributions on those units are eliminated in our consolidated financial statements.

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. In April 2019, ETO issued 32 million of its 7.600% Series E Preferred Units at a price of $25 per unit. As of December 31, 2019 all of our Series A, Series B, Series C, Series D and Series E Preferred Units issued remain outstanding.

The following table summarizes changes in the amounts of our Series A, Series B, Series C, Series D and Series E preferred units for the years ended December 31, 2019, 2018 and 2017 were as follows:

	Preferred Unitholders					
	Series A	Series B	Series C	Series D	Series E	Total
Balance, December 31, 2016	$ —	$ —	$ —	$ —	$ —	$ —
Distributions to partners	—	—	—	—	—	—
Partnership units issued for cash	937	542	—	—	—	1,479
Other, net	—	—	—	—	—	—
Net income	7	5	—	—	—	12
Balance, December 31, 2017	944	547	—	—	—	1,491
Distributions to partners	(44)	(27)	(18)	(11)	—	(100)
Partnership units issued for cash	—	—	436	431	—	867
Other, net	(1)	—	(1)	(1)	—	(3)
Net income	59	36	23	15	—	133
Balance, December 31, 2018	958	556	440	434	—	2,388
Distributions to partners	(59)	(37)	(33)	(34)	(34)	(197)
Partnership units issued for cash	—	—	—	—	780	780
Other, net	—	—	—	—	(1)	(1)
Net income	59	37	33	34	41	204
Balance, December 31, 2019	$ 958	$ 556	$ 440	$ 434	$ 786	$ 3,174

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.

ETO Series E Preferred Units

Distributions on the Series E Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2024, at a rate of 7.600% per annum of the stated liquidation preference of $25. On and after May 15, 2024, distributions on the Series E 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 5.161% per annum. The Series E Preferred Units are redeemable at ETO's option on or after May 15, 2024 at a redemption price of $25 per Series E Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series F Preferred Units

On January 22, 2020, the Partnership issued 500,000 of its 6.750% Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units representing limited partner interest in the Partnership, at a price to the public of $1,000 per unit. Distributions on the Series F Preferred Units are cumulative from and including the original issue date and will be payable semi-annually in arrears on the 15th day of May and November of each year, commencing on May 15, 2020 to, but excluding, May 15, 2025, at a rate equal to 6.750% per annum of the $1,000 liquidation preference. On and after May 15, 2025, the distribution rate on the Series F Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.134% per annum. The Series F Preferred Units are redeemable at ETO's option on or after May 15, 2025 at a redemption price of $1,000 per Series F Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series G Preferred Units

On January 22, 2020, the Partnership issued 1,100,000 of its 7.125% Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units representing limited partner interest in the Partnership, at a price to the public of $1,000 per unit. Distributions on the Series G Preferred Units are cumulative from and including the original issue date and will be payable semi-annually in arrears on the 15th day of May and November of each year, commencing on May 15, 2020 to, but excluding, May 15, 2030, at a rate equal to 7.125% per annum of the $1,000 liquidation preference. On and after May 15, 2030, the distribution rate on the Series G Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.306% per annum. The Series G Preferred Units are redeemable at ETO's option on or after May 15, 2030 at a redemption price of $1,000 per Series G Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

PennTex Tender Offer and Limited Call Right Exercise

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

Subsidiary Equity Transactions

Sunoco LP's 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.

Sunoco LP's Equity Distribution Program

Sunoco LP is party to an equity distribution agreement for an at-the-market ("ATM") offering pursuant to which Sunoco LP may sell its common units from time to time. For the years ended December 31, 2019 and 2018, Sunoco LP issued no units under its ATM program. For the year ended December 31, 2017, Sunoco LP issued an additional 1.3 million units with total net proceeds of $33 million , net of commissions of $0.3 million. As of December 31, 2019, $295 million of Sunoco LP common units remained available to be issued under the currently effective equity distribution agreement.

Sunoco LP's Series A Preferred Units

On March 30, 2017, the Partnership purchased 12.0 million Sunoco LP Series A Preferred Units representing limited partner interests in Sunoco LP in a private placement transaction for an aggregate purchase price of $300 million. The distribution rate of the Sunoco LP Series A Preferred Units is 10.00%, per annum, of the $25.00 liquidation preference per unit until March 30, 2022, at which point the distribution rate will become a floating rate of 8.00% plus three-month LIBOR of the liquidation preference.

In January 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 included the original consideration of $300 million and a 1% call premium plus accrued and unpaid quarterly distributions.

USAC's Distribution Reinvestment Program

During the year ended December 31, 2019 and 2018, distributions of $1 million and $0.6 million, respectively, were reinvested under the USAC distribution reinvestment program resulting in the issuance of approximately 60,584 and 39,280 USAC common units, respectively.

USAC's Warrant Private Placement

On April 2, 2018, USAC issued two tranches of warrants to purchase USAC common units (the "USAC Warrants"), which included USAC Warrants to purchase 5,000,000 common units with a strike price of $17.03 per unit and USAC Warrants to purchase 10,000,000 common units with a strike price of $19.59 per unit. The USAC Warrants may be exercised by the holders thereof at any time beginning on the one year anniversary of the closing date and before the tenth anniversary of the closing date. Upon exercise of the USAC Warrants, USAC may, at its option, elect to settle the USAC Warrants in common units on a net basis.

USAC's Class B Units

The USAC Class B Units, all of which are owned by ETO, are a new class of partnership interests of USAC that 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 the USAC Transaction on April 2, 2018. Each USAC Class B Unit automatically converted into one USAC common unit on the first business day following the record date attributable to the quarter ending June 30, 2019.

On July 30, 2019, the 6,397,965 USAC Class B units held by the Partnership converted into 6,397,965 common units representing limited partner interests in USAC. These common units participate in distributions declared by USAC.

Cash Distributions

ETO Preferred Unit Distributions

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

Period Ended	Record Date	Payment Date	Series A [(1)]	Series B [(1)]	Series C	Series D	Series E
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	—
March 31, 2019	May 1, 2019	May 15, 2019	—	—	0.4609	0.4766	—
June 30, 2019	August 1, 2019	August 15, 2019	31.2500	33.1250	0.4609	0.4766	0.5806 *
September 30, 2019	November 1, 2019	November 15, 2019	—	—	0.4609	0.4766	0.4750
December 31, 2019	February 3, 2020	February 18, 2020	31.2500	33.1250	0.4609	0.4766	0.4750

* Represent prorated initial distributions. Prorated initial distributions on the recently issued Series F and Series G preferred units will be payable in May 2020.

(1) Series A Preferred Units and Series B Preferred Unit distributions are paid on a semi-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, 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
March 31, 2019	May 7, 2019	May 15, 2019	0.8255
June 30, 2019	August 6, 2019	August 14, 2019	0.8255
September 30, 2019	November 5, 2019	November 19, 2019	0.8255
December 31, 2019	February 7, 2020	February 19, 2020	0.8255

USAC Cash Distributions

Subsequent to the Energy Transfer Merger and USAC Transactions described in Note 1 and Note 3, respectively, ETO owned approximately 39.7 million USAC common units and 6.4 million USAC Class B units. Subsequent to the conversion of the USAC Class B Units to USAC common units on July 30, 2019, ETO owns approximately 46.1 million USAC common units. As of December 31, 2019, USAC had approximately 96.6 million common units outstanding. USAC currently has a non-economic general partner interest and no outstanding IDRs.

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
March 31, 2019	April 29, 2019	May 10, 2019	0.5250
June 30, 2019	July 29, 2019	August 9, 2019	0.5250
September 30, 2019	October 28, 2019	November 8, 2019	0.5250
December 31, 2019	January 27, 2020	February 7, 2020	0.5250

Accumulated Other Comprehensive Income

The following table presents the components of AOCI, net of tax:

	December 31, 2019	December 31, 2018
Available-for-sale securities	$ 13	$ 2
Foreign currency translation adjustment	(5)	(5)
Actuarial loss related to pensions and other postretirement benefits	(25)	(48)
Investments in unconsolidated affiliates, net	(1)	9
Total AOCI, net of tax	$ (18)	$ (42)

The table below sets forth the tax amounts included in the respective components of other comprehensive income:

	December 31, 2019	December 31, 2018
Available-for-sale securities	$ (1)	$ (1)
Foreign currency translation adjustment	2	2
Actuarial loss relating to pension and other postretirement benefits	8	12
Total	$ 9	$ 13

8. NON-CASH COMPENSATION PLANS:

ETO Long-Term Incentive Plan

We have previously issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETO Common Units, restricted units, phantom units, distribution equivalent rights ("DERs"), Common Unit appreciation rights, and other unit-based awards.

The Partnership does not currently have any equity compensation plans. In connection with the Energy Transfer Merger in October 2018, all of the Partnership's equity compensation plans, as well as the Partnership's obligations under those plans, were assumed by ET. The Partnership recorded stock compensation expenses of $111 million, $105 million and $99 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Subsidiary Long-Term Incentive Plans

Each of Sunoco LP and USAC has granted restricted or phantom unit awards (collectively, the "Subsidiary Unit Awards") to employees and directors that entitle the grantees to receive common units of the respective subsidiary. In some cases, at the discretion of the respective subsidiary's compensation committee, the grantee may instead receive an amount of cash equivalent to the value of common units upon vesting. Substantially all of the Subsidiary Unit Awards are time-vested grants, which generally vest over a three or five-year period, that entitles the grantees of the unit awards to receive an amount of cash equal to the per unit cash distributions made by the respective subsidiaries during the period the restricted unit is outstanding.

The following table summarizes the activity of the Subsidiary Unit Awards:

	Sunoco LP		USAC	
	Number of Units	Weighted Average Grant-Date Fair Value Per Unit	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2018	2.1	$ 29.15	1.4	$ 14.98
Awards granted	0.7	30.70	0.7	15.88
Awards vested	(0.5)	30.04	(0.3)	13.06
Awards forfeited	(0.2)	28.16	—	16.78
Unvested awards as of December 31, 2019	2.1	29.21	1.8	15.09

The following table summarizes the weighted average grant-date fair value per unit award granted:

	Years Ended December 31,		
	2019	2018	2017
Sunoco LP	$ 30.70	$ 27.67	$ 28.31
USAC	15.88	15.47	N/A

The total fair value of Subsidiary Unit Awards vested for the years ended December 31, 2019, 2018 and 2017 was $17 million, $22 million and $9 million, respectively, based on the market price of Sunoco LP and USAC common units as of the vesting date for the years ended December 31, 2019 and 2018 and Sunoco LP for the year ended December 31, 2017. As of December 31, 2019, estimated compensation cost related to Subsidiary Unit Awards not yet recognized was $57 million, and the weighted average period over which this cost is expected to be recognized in expense is 3.6 years.

9. INCOME TAXES:

As a partnership, we are not subject to United States federal income tax and most state income taxes. However, the Partnership conducts certain activities through corporate subsidiaries which are subject to federal and state income taxes. The components of the federal and state income tax expense (benefit) of our taxable subsidiaries were summarized as follows:

	Years Ended December 31,		
	2019	2018	2017
Current expense (benefit):			
Federal	$ (20)	$ (7)	$ 53
State	(2)	20	(16)
Total	(22)	13	37
Deferred expense (benefit):			
Federal	176	183	(2,025)
State	45	(191)	184
Total	221	(8)	(1,841)
Total income tax expense (benefit)	$ 199	$ 5	$ (1,804)

Historically, our effective tax rate has differed from the statutory rate primarily due to Partnership earnings that are not subject to United States federal and most state income taxes at the partnership level. A reconciliation of income tax expense at the United States statutory rate to the Partnership's income tax benefit for the years ended December 31, 2019, 2018 and 2017 is as follows:

	Years Ended December 31,		
	2019	2018	2017
Income tax expense at United States statutory rate	$ 1,131	$ 849	$ 402
Increase (reduction) in income taxes resulting from:			
Partnership earnings not subject to tax	(940)	(718)	(626)
Federal rate change	—	—	(1,784)
Goodwill impairments	—	—	208
State income taxes (net of federal income tax effects)	14	(125)	123
Dividend received deduction	(3)	(5)	(14)
Change in tax status of subsidiary	—	—	(124)
Other	(3)	4	11
Income tax expense (benefit)	$ 199	$ 5	$ (1,804)

Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows:

	December 31,	
	2019	2018
Deferred income tax assets:		
Net operating losses, alternative minimum tax credit and other carryforwards	$ 936	$ 768
Pension and other postretirement benefits	7	34
Long-term debt	—	13
Other	85	181
Total deferred income tax assets	1,028	996
Valuation allowance	(95)	(96)
Net deferred income tax assets	$ 933	$ 900
Deferred income tax liabilities:		
Property, plant and equipment	$ (464)	$ (742)
Investments in affiliates	(3,547)	(2,869)
Trademarks	(72)	(63)
Other	(21)	(110)
Total deferred income tax liabilities	(4,104)	(3,784)
Net deferred income taxes	$ (3,171)	$ (2,884)

As of December 31, 2019, ETP Holdco had a federal net operating loss carryforward of $2.65 billion, of which $1.10 billion will expire in 2031 through 2037 while the remaining can be carried forward indefinitely. As of December 31, 2019, SemGroup Corporation had a federal net operating loss carryforward of $766 million of which $185 million will expire between 2031 and 2037 while the remaining can be carried forward indefinitely. As of December 31, 2019, Sunoco Property Company LLC, a corporate subsidiary of Sunoco LP, has no federal net operating loss carryforward.

Our corporate subsidiaries have $15 million of federal alternative minimum tax credits at December 31, 2019, of which $8 million is expected to be reclassified to current income tax receivable in 2020 pursuant to the Tax Cuts and Jobs Act. Our corporate subsidiaries have state net operating loss carryforward benefits of $118 million, net of federal tax, some of which will expire between 2020 and 2038, while others are carried forward indefinitely. Our corporate subsidiaries have Canadian net operating losses of $68 million that will begin to expire in 2033 and foreign tax credits of $45 million that will begin to expire in 2020 A valuation allowance of $49 million is applicable to the state net operating loss carryforward benefits primarily attributable to significant restrictions on their use in the Commonwealth of Pennsylvania. A separate valuation allowance of $46 million is attributable to foreign tax credits.

The following table sets forth the changes in unrecognized tax benefits:

	Years Ended December 31,		
	2019	2018	2017
Balance at beginning of year	$ 624	$ 609	$ 615
Additions attributable to tax positions taken in the current year	—	8	—
Additions attributable to tax positions taken in prior years	11	7	28
Reduction attributable to tax positions taken in prior years	(541)	—	(25)
Lapse of statute	—	—	(9)
Balance at end of year	$ 94	$ 624	$ 609

As of December 31, 2019, we have $90 million ($72 million after federal income tax benefits) related to tax positions which, if recognized, would impact our effective tax rate.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2019, we recognized interest and penalties of $1 million. At December 31, 2019, we have interest and penalties accrued of $3 million, net of tax.

We appealed the adverse Court of Federal Claims decision against ETC Sunoco regarding the IRS' denial of ethanol blending credits claims under Section 6426 to the Federal Circuit. The Federal Circuit affirmed the CFC's denial on November 1, 2018. ETC Sunoco filed a petition for certiorari with the Supreme Court on May 24, 2019 to review the Federal Circuit's affirmation of the CFC's ruling, and the Court denied Sunoco's petition on October 7, 2019. The petition for certiorari applied to ETC Sunoco's 2004 through 2009 tax years, and 2010 through 2011 are on extension with the IRS through March 30, 2020. Due to the uncertainty surrounding the litigation, a reserve of $530 million was previously established for the full amount of the pending refund claims, and the receivable and reserve for this issue were netted in the consolidated balance sheet. Subsequent to the Supreme Court's denial of the petition in October 2019, the receivable and reserve have been reversed, with no impact to the Partnership's financial position and results of operations.

In November 2015, the Pennsylvania Commonwealth Court determined in Nextel Communications v. Commonwealth (“Nextel”) that the Pennsylvania limitation on NOL carryforward deductions violated the uniformity clause of the Pennsylvania Constitution and struck the NOL limitation in its entirety. In October 2017, the Pennsylvania Supreme Court affirmed the decision with respect to the uniformity clause violation; however, the Court reversed with respect to the remedy and instead severed the flat-dollar limitation, leaving the percentage-based limitation intact. Nextel subsequently filed a petition for writ of certiorari with the United States Supreme Court, and this was denied on June 11, 2018. Now certain Pennsylvania taxpayers are proceeding with litigation in Pennsylvania state courts on issues not addressed by the Pennsylvania Supreme Court in Nextel, specifically, whether the Due Process and Equal Protection Clauses of the United States Constitution and the Remedies Clause of the Pennsylvania Constitution require a court to grant the taxpayer relief. ETC Sunoco has recognized approximately $67 million ($53 million after federal income tax benefits) in tax benefit based on previously filed tax returns and certain previously filed protective claims as relates to its cases currently held pending the Nextel matter. However, based upon the Pennsylvania Supreme Court’s October 2017 decision, and because of uncertainty in the breadth of the application of the decision, we have reserved $34 million ($27 million after federal income tax benefits) against the receivable.

In general, ETO and its subsidiaries are no longer subject to examination by the IRS, and most state jurisdictions, for the 2014 and prior tax years.

ETO and its subsidiaries also have various state and local income tax returns in the process of examination or administrative appeal in various jurisdictions. We believe the appropriate accruals or unrecognized tax benefits have been recorded for any potential assessment with respect to these examinations.

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

FERC Proceedings

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. On August 30, 2019, Panhandle filed a general rate proceeding under Section 4 of the Natural Gas Act. The Natural Gas Act Section 5 and Section 4 proceedings were consolidated by the Order dated October 1, 2019. A hearing in the combined proceedings commenced on August 25, 2020 and adjourned on September 15, 2020. An initial decision is expected in early 2021.

By Order issued February 19, 2019, the FERC initiated a review of Southwest Gas' existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Southwest Gas are just and reasonable and set the matter for hearing. Southwest Gas filed a cost and revenue study on May 6, 2019. On July 10, 2019, Southwest Gas filed an Offer of Settlement in this Section 5 proceeding, which settlement was supported or not opposed by Commission Trial Staff and all active parties. By order dated October 29, 2019, the FERC approved the settlement as filed, and there is not a material impact on revenue.

In addition, on November 30, 2018, Sea Robin filed a rate case pursuant to Section 4 of the Natural Gas Act. On July 22, 2019, Sea Robin filed an Offer of Settlement in this Section 4 proceeding, which settlement was supported or not opposed by Commission Trial Staff and all active parties. By order dated October 17, 2019, the FERC approved the settlement as filed, and there is not a material impact on revenue.

Commitments

In the normal course of business, ETO purchases, processes and sells natural gas pursuant to long-term contracts and enters into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. ETO believes that the terms of these agreements are commercially reasonable and will not have a material adverse effect on its financial position or results of operations.

Our joint venture agreements require that we funds our proportionate share of capital contributions to its unconsolidated affiliates. Such contributions will depend upon our unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

We have certain non-cancelable rights-of-way ("ROW") commitments, which require fixed payments and either expire upon our chosen abandonment or at various dates in the future. The table below reflects ROW expense included in operating expenses in the accompanying statements of operations:

	Years Ended December 31,		
	2019	2018	2017
ROW expense	$ 45	$ 46	$ 46

PES Refinery Fire and Bankruptcy

We own an approximately 7.4% non-operating interest in PES, which owns a refinery in Philadelphia. In addition, the Partnership provides logistics services to PES under commercial contracts and Sunoco LP has historically purchased refined products from PES. In June 2019, an explosion and fire occurred at the refinery complex.

On July 21, 2019, PES Holdings, LLC and seven of its subsidiaries (collectively, the "Debtors") filed voluntary petitions in the United States Bankruptcy Court for the District of Delaware seeking relief under the provisions of Chapter 11 of the United States Bankruptcy Code, as a result of the explosion and fire at the Philadelphia refinery complex. The Debtors have also defaulted on a $75 million note payable to a subsidiary of the Partnership. In June 2020, the Partnership received $12 million from PES on the note payable and recorded a reserve for the remaining $63 million note balance.

In addition, the Partnership's subsidiaries retained certain environmental remediation liabilities when the refinery was sold to PES. As of December 31, 2019, the Partnership has funded these environmental remediation liabilities through its wholly-owned captive insurance company, based upon actuarially determined estimates for such costs, and these liabilities are included in the total environmental liabilities discussed below under "Environmental Remediation." It may be necessary for the Partnership to record additional environmental remediation liabilities in the future depending upon the use of such property by the buyer; however, management is not currently able to estimate such additional liabilities.

PES has rejected certain of the Partnership's commercial contracts pursuant to Section 365 of the Bankruptcy Code; however, the impact of the bankruptcy on the Partnership's commercial contracts and related revenue loss (temporary or permanent) is unknown at this time. In addition, Sunoco LP has been successful at acquiring alternative supplies to replace fuel volume lost from PES and does not anticipate any material impact to its business going forward.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude oil are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

Dakota Access Pipeline

On July 27, 2016, the Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the United States District Court for the District of Columbia ("District Court") challenging permits issued by the United States Army Corps of Engineers ("USACE") permitting Dakota Access, LLC ("Dakota Access") to cross the Missouri River at Lake Oahe in North Dakota. The case was subsequently amended to challenge an easement issued by the USACE allowing the pipeline to cross land owned by the USACE adjacent to the Missouri River. Dakota Access and the Cheyenne River Sioux Tribe ("CRST") intervened. Separate lawsuits filed by the Oglala Sioux Tribe ("OST") and the Yankton Sioux Tribe ("YST") were consolidated with this action and several individual tribal members intervened (collectively, with SRST and CRST, the "Tribes"). On March 25, 2020, the court remanded the case back to the USACE for preparation of an Environment Impact Statement. On July 6, 2020, the court vacated the easement and ordered Dakota Access to be shut down and emptied of oil by August 5, 2020. Dakota Access and USACE appealed to the United States Court of Appeals for the District of Columbia ("Court of Appeals") which granted an administrative stay of the District Court's July 6 order and ordered further briefing on whether to fully stay the July 6 order. On August 5, 2020, the Court of Appeals granted a stay of the portion of the District Court order that required Dakota Access to shut the pipeline down and empty it of oil. The Court of Appeals also denied a motion to stay the March 25 order pending a decision on the merits by the Court of Appeals as to whether USACE will be required to prepare an Environmental Impact Statement. In addition, the Court of Appeals denied a motion to stay the District Court's order to vacate the easement during this appeal process. The August 5 order also states that the Court of Appeals expects USACE to clarify its position with respect to whether USACE intends to allow the continued operation of the pipeline notwithstanding the vacator of the easement and that the District Court may consider additional relief if necessary.

On August 10, 2020, the District Court ordered USACE to submit a status report by August 31, 2020 clarifying its position with regard to its decision making process with respect to the continued operation of the pipeline. On August 31, 2020, USACE submitted a status report that indicated that it considers the presence of the pipeline at the Lake Oahe crossing without an easement to constitute an encroachment on federal land, and that it was still considering whether to exercise its enforcement discretion regarding this encroachment. Following the filing of this status report, the District Court ordered briefing on whether to enjoin the operation of the pipeline, with briefing scheduled to conclude by December 18, 2020.

Briefing on the merits of the appeal to the Court of Appeals has been completed, and oral argument took place on November 4, 2020. As a result of the ruling by the Court of Appeals related to the motions to stay and the District Court's briefing schedule related to the injunction issue, it is expected that the pipeline will continue to operate during the pendency of the appeals process with the Court of Appeals.

ET cannot determine when or how these lawsuits will be resolved or the impact they may have on the Dakota Access pipelines; however, ET expects after the law and complete record are fully considered, the issues in this litigation will be resolved in a manner that will allow the pipeline to continue to operate.

Mont Belvieu Incident

On June 26, 2016, a hydrocarbon storage well located on another operator's facility adjacent to Lone Star NGL Mont Belvieu's ("Lone Star") facilities in Mont Belvieu, Texas, experienced an over-pressurization resulting in a subsurface release. The subsurface release caused a fire at Lone Star's South Terminal and damage to Lone Star's storage well operations at its South and North Terminals. Normal operations have resumed at the facilities with the exception of one of Lone Star's storage wells, however, Lone Star is still quantifying the extent of its incurred and ongoing damages and has obtained, and will continue to seek, reimbursement for these losses.

MTBE Litigation

ETC Sunoco Holdings LLC and 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, 2019, Sunoco is a defendant in five cases, including one case each initiated by the States of Maryland 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 ETO, ETP Holdco Corporation, and Sunoco Partners Marketing & Terminals L.P. ("SPMT").

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

Regency Merger Litigation

On June 10, 2015, Adrian Dieckman ("Dieckman"), a purported Regency unitholder, filed a class action complaint related to the Regency-ETO merger (the "Regency Merger") in the Court of Chancery of the State of Delaware (the "Regency Merger Litigation"), on behalf of Regency's common unitholders against Regency GP LP, Regency GP LLC, ET, ETO, ETP GP, and the members of Regency's board of directors.

The Regency Merger Litigation alleges that the Regency Merger breached the Regency partnership agreement. On March 29, 2016, the Delaware Court of Chancery granted the defendants' motion to dismiss the lawsuit in its entirety. Plaintiff appealed, and the Delaware Supreme Court reversed the judgment of the Court of Chancery. Plaintiff then filed an Amended Verified Class Action Complaint, which defendants moved to dismiss. The Court of Chancery granted in part and denied in part the motions to dismiss, dismissing the claims against all defendants other than Regency GP, LP and Regency GP LLC (the "Regency Defendants"). The Court of Chancery later granted Plaintiff's unopposed motion for class certification. Trial was held on December 10-16, 2019, and a post-trial hearing was held on May 6, 2020.

The Regency Defendants cannot predict the outcome of the Regency Merger Litigation or any lawsuits that might be filed subsequent to the date of this filing; nor can the Regency Defendants predict the amount of time and expense that will be required to resolve the Regency Merger Litigation. The Regency Defendants believe the Regency Merger Litigation is without merit and intend to vigorously defend against it.

Enterprise Products Partners, L.P. and Enterprise Products Operating LLC Litigation

On January 27, 2014, a trial commenced between ETO against Enterprise Products Partners, L.P. and Enterprise Products Operating LLC (collectively, "Enterprise") and Enbridge (US) Inc. Trial resulted in a verdict in favor of ETO against Enterprise that consisted of $319 million in compensatory damages and $595 million in disgorgement to ETO. The jury also found that ETO owed Enterprise $1 million under a reimbursement agreement. On July 29, 2014, the trial court entered a final judgment in favor of ETO and awarded ETO $536 million, consisting of compensatory damages, disgorgement, and pre-judgment interest. The trial court also ordered that ETO shall be entitled to recover post-judgment interest and costs of court and that Enterprise is not entitled to any net recovery on its counterclaims. Enterprise filed a notice of appeal with the Court of Appeals. On July 18, 2017, the Court of Appeals issued its opinion and reversed the trial court's judgment. ETO's motion for rehearing to the Court of Appeals was denied. On November 27, 2017, ETO filed a Petition for Review with the Texas Supreme Court. On June 8, 2018, the Texas Supreme Court ordered briefing on the merits. On June 28, 2019, the Texas Supreme Court granted ETO's petition for review and oral argument was heard on October 8, 2019. On January 31, 2020, the Texas Supreme Court affirmed the judgment of the Court of Appeals.

Rover

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency ("Ohio EPA") filed suit against Rover and other defendants seeking to recover civil penalties allegedly owed and certain injunctive relief related to permit compliance. The defendants filed several motions to dismiss, which were granted on all counts. The Ohio EPA appealed, and on December 9, 2019, the Fifth District Court of Appeals entered a unanimous judgment affirming the trial court. The Ohio EPA sought review from the Ohio Supreme Court, which the defendants opposed in briefs filed in February 2020. On April 22, 2020, the Ohio Supreme Court granted the Ohio EPA's request for review. Briefing has concluded. The Ohio Supreme Court has not yet scheduled oral argument.

Bayou Bridge

On January 11, 2018, environmental groups and a trade association filed suit against the USACE in the United States District Court for the Middle District of Louisiana. Plaintiffs allege that the USACE's issuance of permits authorizing the construction of the Bayou Bridge Pipeline through the Atchafalaya Basin ("Basin") violated the National Environmental Policy Act, the Clean Water Act, and the Rivers and Harbors Act. ETO, through its subsidiary Bayou Bridge Pipeline, LLC ("Bayou Bridge"), intervened on January 26, 2018.

On March 25, 2020, the Court granted summary judgment in favor of the USACE. Plaintiffs did not appeal by the deadline, and the case has concluded.

Revolution

On September 10, 2018, a pipeline release and fire (the "Incident") occurred on the Revolution pipeline, a natural gas gathering line located in Center Township, Beaver County, Pennsylvania. There were no injuries. On February 8, 2019, the Pennsylvania Department of Environmental Protection ("PADEP") issued a Permit Hold on any requests for approvals/permits or permit amendments for any project in Pennsylvania pursuant to the state's water laws. The Partnership filed an appeal of the Permit Hold with the Pennsylvania Environmental Hearing Board. On January 3, 2020, the Partnership entered into a Consent Order and Agreement with the Department in which, among other things, the Permit Hold was lifted, the Partnership agreed to pay a $28.6 million civil penalty and fund a $2 million community environmental project, and all related appeals were withdrawn.

The Pennsylvania Office of Attorney General has commenced an investigation regarding the Incident, and the United States Attorney for the Western District of Pennsylvania has issued a federal grand jury subpoena for documents relevant to the Incident. The scope of these investigations is not further known at this time.

Chester County, Pennsylvania Investigation

In December 2018, the former Chester County District Attorney ("DA") sent a letter to the Partnership stating that his office was investigating the Partnership and related entities for "potential crimes" related to the Mariner East pipelines.

Subsequently, the matter was submitted to an Investigating Grand Jury in Chester County, Pennsylvania, which has issued subpoenas seeking documents and testimony. On September 24, 2019, the former DA sent a Notice of Intent to the Partnership of its intent to pursue an abatement action if certain conditions were not remediated. The Partnership responded to the Notice of Intent within the prescribed time period. To date, the Partnership is not aware of any further action with regard to this Notice.

In December 2019, the former DA announced charges against a current employee related to the provision of security services. On June 25, 2020, a preliminary hearing was held on the charges against the employee, and the judge dismissed all charges.

Delaware County, Pennsylvania Investigation

On March 11, 2019, the Delaware County District Attorney's Office ("DA") announced that the DA and the Pennsylvania Attorney General's Office, at the request of the DA, are conducting an investigation of alleged criminal misconduct involving the construction and related activities of the Mariner East pipelines in Delaware County. The Partnership has not been appraised of the specific conduct under investigation. While the Partnership will cooperate with the investigation, it intends to vigorously defend itself.

Other Litigation and Contingencies

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2019 and 2018, accruals of approximately $120 million and $53 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued.

In addition, other legal proceedings exist that are considered reasonably possible to result in unfavorable outcomes. For those where possible losses can be estimated, the range of possible losses related to these contingent obligations is estimated to be up to $80 million; however, no accruals have been recorded as of December 31, 2019.

Environmental Matters

Our operations are subject to extensive federal, tribal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations but there can be no assurance that such costs will not be material in the future or that such future compliance with existing, amended or new legal requirements will not have a material adverse effect on our business and operating results. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, natural resource damages, the issuance of injunctions in affected areas and the filing of federally authorized citizen suits. Contingent losses related to all significant known environmental matters have been accrued and/or separately disclosed. However, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs.

In February 2017, we received letters from the DOJ on behalf of EPA and Louisiana Department of Environmental Quality (“LDEQ”) notifying SPLP and Mid-Valley that enforcement actions were being pursued for three separate crude oil releases: (a) an estimated 550 barrels released from the Colmesneil-to-Chester pipeline in Tyler County, Texas (“Colmesneil”) which allegedly occurred in February 2013; (b) an estimated 4,509 barrels released from the Longview-to-Mayersville pipeline in Caddo Parish, Louisiana (a/k/a Milepost 51.5) which allegedly occurred in October 2014; and (c) an estimated 40 barrels released from the Wakita 4-inch gathering line in Oklahoma which allegedly occurred in January 2015. In January 2019, a Consent Decree approved by all parties as well as an accompanying Complaint was filed in the United States District Court for the Western District of Louisiana seeking public comment and final court approval to resolve all penalties with DOJ and LDEQ for the three releases. Subsequently, the court approved the Consent Decree and the penalty payment of $5.4 million was satisfied. The Consent Decree requires certain injunctive relief to be completed on the Longview-to-Mayersville pipeline within three years but the injunctive relief is not expected to have any material impact on operations. In addition to resolution of the civil penalty and injunctive relief, we continue to discuss natural resource damages with the Louisiana trustees related to the Caddo Parish, Louisiana release.

In October 2018, Pipeline Hazardous Materials Safety Administration (“PHMSA”) issued a notice of proposed safety order (the “Notice”) to SPMT, a wholly owned subsidiary of ETO. The Notice alleged that conditions exist on certain pipeline facilities owned and operated by SPMT in Nederland, Texas that pose a pipeline integrity risk to public safety, property or the environment. The Notice also made preliminary findings of fact and proposed corrective measures. SPMT responded to the Notice by submitting a timely written response on November 2, 2018, attended an informal consultation held on January 30, 2019 and entered into a consent agreement with PHMSA resolving the issues in the Notice as of March 2019. SPMT is currently awaiting response from PHMSA regarding the approval status of the submitted Remedial Work Plan.

On June 4, 2019, the Oklahoma Corporation Commission’s (“OCC”) Transportation Division filed a complaint against SPLP seeking a penalty of up to $1 million related to a May 2018 rupture near Edmond, Oklahoma. The release occurred on the Noble to Douglas 8” pipeline in an area of external corrosion and caused the release of approximately fifteen barrels of crude oil. SPLP responded immediately to the release and remediated the surrounding environment and pipeline in cooperation with the OCC. The OCC filed the complaint alleging that SPLP failed to provide adequate cathodic protection to the pipeline causing the failure. SPLP is negotiating a settlement agreement with the OCC for a lesser penalty. The OCC has accepted our counter offer in conjunction with a proposed consent order. The Consent Order will be presented to the OCC at a final hearing the date of which is to be determined.

Environmental Remediation

Our subsidiaries are responsible for environmental remediation at certain sites, including the following:

- certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could be contractually responsible for contamination caused by other parties.
- certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- legacy sites related to Sunoco that are subject to environmental assessments, including formerly owned terminals and other logistics assets, retail sites that Sunoco no longer operates, closed and/or sold refineries and other formerly owned sites.

  Sunoco is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party (“PRP”). As of December 31, 2019, Sunoco had been named as a PRP at approximately 40 identified or potentially identifiable “Superfund” sites under federal and/or comparable state law. Sunoco is usually one of a number of companies identified as a PRP at a site. Sunoco has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco’s purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

To the extent estimable, expected remediation costs are included in the amounts recorded for environmental matters in our consolidated balance sheets. In some circumstances, future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. To the extent that an environmental remediation obligation is recorded by a subsidiary that applies regulatory accounting policies, amounts that are expected to be recoverable through tariffs or rates are recorded as regulatory assets on our consolidated balance sheets.

The table below reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	December 31,	
	2019	2018
Current	$ 46	$ 42
Non-current	274	295
Total environmental liabilities	$ 320	$ 337

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.

During the years ended December 31, 2019 and 2018, the Partnership recorded $39 million and $48 million, respectively, of expenditures related to environmental cleanup programs.

Our pipeline operations are subject to regulation by the United States Department of Transportation under PHMSA, pursuant to which PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

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

11. REVENUE:

The following disclosures discuss the Partnership’s revised revenue recognition policies upon the adoption of ASU 2014-09 on January 1, 2018. These policies were applied to the amounts reflected in the Partnership’s consolidated financial statements for the years ended December 31, 2019 and 2018, while the amounts reflected in the Partnership’s consolidated financial statements for the year ended December 31, 2017 were recorded under the Partnership’s previous accounting policies.

Disaggregation of revenue

The major types of revenue within our reportable segments, are as follows:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- NGL and refined products transportation and services;

- crude oil transportation and services;
- investment in Sunoco LP;
  - fuel distribution and marketing;
  - all other;
- investment in USAC;
  - contract operations;
  - retail parts and services; and
- all other.

Note 16 depicts the disaggregation of revenue by segment, with revenue amounts reflected in accordance with ASC Topic 606 for 2019 and 2018 and ASC Topic 605 for 2017.

Intrastate transportation and storage revenue

Our intrastate transportation and storage segment's revenues are determined primarily by the volume of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines or that is injected or withdrawn into or out of our storage facilities. Firm transportation and storage contracts require customers to pay certain minimum fixed fees regardless of the volume of commodity they transport or store. These contracts typically include a variable incremental charge based on the actual volume of transportation commodity throughput or stored commodity injected/withdrawn. Under interruptible transportation and storage contracts, customers are not required to pay any fixed minimum amounts, but are instead billed based on actual volume of commodity they transport across our pipelines or inject/withdraw into or out of our storage facilities. Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation or storage) daily over the life of the contract, which is fundamentally a "stand-ready" service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this "stand-ready" service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of service, but such promise is made on a case-by-case basis at the time the customer requests the service and we accept the customer's request. Revenue is recognized for interruptible contracts at the time the services are performed.

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.

Interstate transportation and storage revenue

Our interstate transportation and storage segment's revenues 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 or that is injected into or withdrawn out of our storage facilities. Our interstate transportation and storage segment's contracts can be firm or interruptible. Firm transportation and storage contracts require customers to pay certain minimum fixed fees regardless of the volume of commodity transported or stored. In exchange for such fees, we must stand ready to perform a contractually agreed-upon minimum volume of services whenever the customer requests such services. These contracts typically include a variable incremental charge based on the actual volume of transportation commodity throughput or stored commodity injected or withdrawn. Under interruptible transportation and storage contracts, customers are not required to pay any fixed minimum amounts, but are instead billed based on actual volume of commodity they transport across our pipelines or inject into or withdraw out of our storage facilities. Consequently, we are not required to stand ready to provide any contractually agreed-upon volume of service, but instead provides the services based on existing capacity at the time the customer requests the services. Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation or storage) daily over the life of the contract, which is fundamentally a “stand-ready” service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this “stand-ready” service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of services, but such promise is made on a case-by-case basis at the time the customer requests the service and we accept the customer’s request. Revenue is recognized for interruptible contracts at the time the services are performed.

Lake Charles LNG’s revenues are primarily derived from terminalling services for shippers by receiving LNG at the facility for storage and delivering such LNG to shippers, either in liquid state or gaseous state after regasification. Lake Charles LNG derives all of its revenue from a series of long term contracts with a wholly-owned subsidiary of Royal Dutch Shell plc (“Shell”). Terminalling revenue is generated from fees paid by Shell for storage and other associated services at the terminal. Payment for services under these contracts are typically due the month after the services have been performed.

The terminalling agreements are considered to be firm agreements, because they include fixed fee components that are charged regardless of the volumes transported by Shell or services provided at the terminal.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (terminalling) daily over the life of the contract, which is fundamentally a “stand-ready” service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this “stand-ready” service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

Midstream revenue

Our midstream segment’s revenues are derived primarily from margins we earn for natural gas volumes that are gathered, processed, and/or transported. The various types of revenue contracts our midstream segment enters into include:

Fixed fee gathering and processing: Contracts under which we provide gathering and processing services in exchange for a fixed cash fee per unit of volume. Revenue for cash fees is recognized when the service is performed.

Keepwhole: Contracts under which we gather raw natural gas from a third party producer, process the gas to convert it to pipeline quality natural gas, and redeliver to the producer a thermal-equivalent volume of pipeline quality natural gas. In exchange for these services, we retain the NGLs extracted from the raw natural gas received from the producer as well as cash fees paid by the producer. The value of NGLs retained as well as cash fees is recognized as revenue when the services are performed.

Percent of Proceeds (“POP”): Contracts under which we provide gathering and processing services in exchange for a specified percentage of the producer’s commodity (“POP percentage”) and also in some cases additional cash fees. The two types of POP revenue contracts are described below:

- *In-Kind POP:* We retain our POP percentage (non-cash consideration) and also any additional cash fees in exchange for providing the services. We recognize revenue for the non-cash consideration and cash fees at the time the services are performed.
- *Mixed POP:* We purchase NGLs from the producer and retain a portion of the residue gas as non-cash consideration for services provided. We may also receive cash fees for such services. Under Topic 606, these agreements were determined to be hybrid agreements which were partially supply agreements (for the NGLs we purchased) and customer agreements (for the services provided related to the product that was returned to the customer). Given that these are hybrid agreements, we split the cash and non-cash consideration between revenue and a reduction of costs based on the value of the service provided vs. the value of the supply received.

Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligations with respect to our midstream segment's contracts are to provide gathering, transportation and processing services, each of which would be completed on or about the same time, and each of which would be recognized on the same line item on the income statement, therefore identification of separate performance obligations would not impact the timing or geography of revenue recognition.

Certain contracts of our midstream segment include throughput commitments under which customers commit to purchasing a certain minimum volume of service over a specified time period. If such volume of service is not purchased by the customer, deficiency fees are billed to the customer. In some cases, the customer is allowed to apply any deficiency fees paid to future purchases of services. In such cases, we defer revenue recognition until the customer uses the deficiency fees for services provided or becomes unable to use the fees as payment for future services due to expiration of the contractual period the fees can be applied or physical inability of the customer to utilize the fees due to capacity constraints.

Our midstream segment also generates revenues from the sale of residue gas and NGLs at the tailgate of our processing facilities primarily to affiliates and some third-party customers.

NGL and refined products transportation and services revenue

Our NGL and refined products segment's revenues are primarily derived from transportation, fractionation, blending, and storage of NGL and refined products as well as acquisition and marketing activities. Revenues are generated utilizing a complementary network of pipelines, storage and blending facilities, and strategic off-take locations that provide access to multiple NGL markets. Transportation, fractionation, and storage revenue is generated from fees charged to customers under a combination of firm and interruptible contracts. Firm contracts are in the form of take-or-pay arrangements where certain fees will be charged to customers regardless of the volume of service they request for any given period. Under interruptible contracts, customers are not required to pay any fixed minimum amounts, but are instead billed based on actual volume of service provided for any given period. Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation, fractionation, blending, or storage) daily over the life of the contract, which is fundamentally a "stand-ready" service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this "stand-ready" service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of services, but such promise is made on a case-by-case basis at the time the customer requests the service and we accept the customer's request. Revenue is recognized for interruptible contracts at the time the services are performed.

Acquisition and marketing contracts are in most cases short-term agreements involving purchase and/or sale of NGLs and other related hydrocarbons at market rates. These contracts were not affected by ASC 606.

Crude oil transportation and services revenue

Our crude oil transportation and services segment revenues are primarily derived from providing transportation, terminalling and acquisition and marketing services to crude oil markets throughout the southwest, midwest and northeastern United States. Crude oil transportation revenue is generated from tariffs paid by shippers utilizing our transportation services and is generally recognized as the related transportation services are provided. Crude oil terminalling revenue is generated from fees paid by customers for storage and other associated services at the terminal. Crude oil acquisition and marketing revenue is generated from sale of crude oil acquired from a variety of suppliers to third parties. Payment for services under these contracts are typically due the month after the services have been performed.

Certain transportation and terminalling agreements are considered to be firm agreements, because they include fixed fee components that are charged regardless of the volume of crude oil transported by the customer or services provided at the terminal. For these agreements, any fixed fees billed in excess of services provided are not recognized as revenue until the earlier of (i) the time at which the customer applies the fees against cost of service provided in a later period, or (ii) the customer becomes unable to apply the fees against cost of future service due to capacity constraints or contractual terms.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation or terminalling) daily over the life of the contract, which is fundamentally a “stand-ready” service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this “stand-ready” service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of service, but such promise is made on a case-by-case basis at the time the customer requests the service and/or product and we accept the customer’s request. Revenue is recognized for interruptible contracts at the time the services are performed.

Acquisition and marketing contracts are in most cases short-term agreements involving purchase and/or sale of crude oil at market rates. These contracts were not affected by ASC 606.

Sunoco LP’s fuel distribution and marketing revenue

Sunoco LP’s fuel distribution and marketing operations earn revenue from the following channels: sales to Dealers, sales to Distributors, Unbranded Wholesale Revenue, Commission Agent Revenue, Rental Income and Other Income. Motor fuel revenue consists primarily of the sale of motor fuel under supply agreements with third party customers and affiliates. Fuel supply contracts with Sunoco LP’s customers generally provide that Sunoco LP distribute motor fuel at a formula price based on published rates, volume-based profit margin, and other terms specific to the agreement. The customer is invoiced the agreed-upon price with most payment terms ranging less than 30 days. If the consideration promised in a contract includes a variable amount, Sunoco LP estimates the variable consideration amount and factors in such an estimate to determine the transaction price under the expected value method.

Revenue is recognized under the motor fuel contracts at the point in time the customer takes control of the fuel. At the time control is transferred to the customer the sale is considered final, because the agreements do not grant customers the right to return motor fuel. Under the new standard, to determine when control transfers to the customer, the shipping terms of the contract are assessed as shipping terms are considered a primary indicator of the transfer of control. For FOB shipping point terms, revenue is recognized at the time of shipment. The performance obligation with respect to the sale of goods is satisfied at the time of shipment since the customer gains control at this time under the terms. Shipping and/or handling costs that occur before the customer obtains control of the goods are deemed to be fulfillment activities and are accounted for as fulfillment costs. Once the goods are shipped, Sunoco LP is precluded from redirecting the shipment to another customer and revenue is recognized.

Commission agent revenue consists of sales from commission agent agreements between Sunoco LP and select operators. Sunoco LP supplies motor fuel to sites operated by commission agents and sells the fuel directly to the end customer. In commission agent arrangements, control of the product is transferred at the point in time when the goods are sold to the end customer. To reflect the transfer of control, Sunoco LP recognizes commission agent revenue at the point in time fuel is sold to the end customer.

Sunoco LP receives rental income from leased or subleased properties. Revenue from leasing arrangements for which Sunoco LP is the lessor are recognized ratably over the term of the underlying lease.

Sunoco LP’s all other revenue

Sunoco LP’s all other operations earn revenue from the following channels: Motor Fuel Sales, Rental Income and Other Income. Motor Fuel Sales consist of fuel sales to consumers at company-operated retail stores. Other income includes merchandise revenue that comprises the in-store merchandise and food service sales at company-operated retail stores, and other revenue that represents a variety of other services within Sunoco LP’s all other operations including credit card processing, car washes, lottery, automated teller machines, money orders, prepaid phone cards and wireless services. Revenue from all other operations is recognized when (or as) the performance obligations are satisfied (i.e. when the customer obtains control of the good or the service is provided).

USAC's contract operations revenue

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 the 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. 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.

Variable consideration exists in select contracts when billing rates vary based on actual equipment availability or volume of total installed horsepower.

USAC's contracts with customers may include multiple performance obligations. For such arrangements, USAC allocates revenues to each performance obligation based on its relative standalone service fee. USAC generally determine standalone service fees based on the service fees charged to customers or using expected cost plus margin.

The majority of USAC's service performance obligations are satisfied over time as services are rendered at selected customer locations on a monthly basis and based upon specific performance criteria identified in the applicable contract. The monthly service for each location is substantially the same service month to month and is promised consecutively over the service contract term. USAC measures progress and performance of the service consistently using a straight-line, time-based method as each month passes, because its performance obligations are satisfied evenly over the contract term as the customer simultaneously receives and consumes the benefits provided by its service. If variable consideration exists, it is allocated to the distinct monthly service within the series to which such variable consideration relates. USAC has elected to apply the invoicing practical expedient to recognize revenue for such variable consideration, as the invoice corresponds directly to the value transferred to the customer based on its performance completed to date.

There are typically no material obligations for returns or refunds. USAC's standard contracts do not usually include material non-cash consideration.

USAC's retail parts and services revenue

USAC's retail parts and service revenue is earned primarily on freight and crane charges that are directly reimbursable by USAC's customers and maintenance work on units at its customers' locations that are outside the scope of its 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. There are typically no material obligations for returns, refunds, or warranties. USAC's standard contracts do not usually include material variable or non-cash consideration.

All other revenue

Our all other segment primarily includes our compression equipment business which provides full-service compression design and manufacturing services for the oil and gas industry. It also includes 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. There were no material changes to the manner in which revenues within this segment are recorded under the new standard.

Contract Balances with Customers

The Partnership satisfies its obligations by transferring goods or services in exchange for consideration from customers. The timing of performance may differ from the timing the associated consideration is paid to or received from the customer, thus resulting in the recognition of a contract asset or a contract liability.

The Partnership recognizes a contract asset when making upfront consideration payments to certain customers or when providing services to customers prior to the time at which the Partnership is contractually allowed to bill for such services.

The Partnership recognizes a contract liability if the customer's payment of consideration precedes the Partnership’s fulfillment of the performance obligations. Certain contracts contain provisions requiring customers to pay a fixed fee for a right to use our assets, but allows customers to apply such fees against services to be provided at a future point in time. These amounts are reflected as deferred revenue until the customer applies the deficiency fees to services provided or becomes unable to use the fees as payment for future services due to expiration of the contractual period the fees can be applied or physical inability of the customer to utilize the fees due to capacity constraints. Additionally, Sunoco LP maintains some franchise agreements requiring dealers to make one-time upfront payments for long term license agreements. Sunoco LP recognizes a contract liability when the upfront payment is received and recognizes revenue over the term of the license.

The following table summarizes the consolidated activity of our contract liabilities:

	Contract Liabilities
Balance, January 1, 2018	$ 221
Additions	765
Revenue recognized	(592)
Balance, December 31, 2018	394
Additions	664
Revenue recognized	(681)
Balance, December 31, 2019	$ 377

The balances of receivables from contracts with customers listed in the table below include both current trade receivables and long-term receivables, net of allowance for doubtful accounts. The allowance for receivables represents Sunoco LP’s best estimate of the probable losses associated with potential customer defaults. Sunoco LP determines the allowance based on historical experience and on a specific identification basis.

The balances of Sunoco LP’s contract assets and contract liabilities as of December 31, 2019 and 2018 were as follows:

	December 31, 2019	December 31, 2018
Contract balances:		
Contract asset	$ 117	$ 75
Accounts receivable from contracts with customers	366	347
Contract liability	—	1

Costs to Obtain or Fulfill a Contract

Sunoco LP recognizes an asset from the costs incurred to obtain a contract (e.g. sales commissions) only if it expects to recover those costs. On the other hand, the costs to fulfill a contract are capitalized if the costs are specifically identifiable to a contract, would result in enhancing resources that will be used in satisfying performance obligations in future and are expected to be recovered. These capitalized costs are recorded as a part of other current assets and other non-current assets and are amortized on a systematic basis consistent with the pattern of transfer of the goods or services to which such costs relate. The amount of amortization expense that Sunoco LP recognized for the years ended December 31, 2019 and 2018 was $17 million and $14 million, respectively. Sunoco LP has also made a policy election of expensing the costs to obtain a contract, as and when they are incurred, in cases where the expected amortization period is one year or less.

Performance Obligations

At contract inception, the Partnership assesses the goods and services promised in its contracts with customers and identifies a performance obligation for each promise to transfer a good or service (or bundle of goods or services) that is distinct. To identify the performance obligations, the Partnership considers all the goods or services promised in the contract, whether explicitly stated or implied based on customary business practices. For a contract that has more than one performance obligation, the Partnership allocates the total contract consideration it expects to be entitled to, to each distinct performance obligation based on a standalone-selling price basis. Revenue is recognized when (or as) the performance obligations are satisfied, that is, when the customer obtains control of the good or service. Certain of our contracts contain variable components, which, when combined with the fixed component are considered a single performance obligation. For these types of contracts, only the fixed component of the contracts are included in the table below.

Sunoco LP distributes fuel under long-term contracts to branded distributors, branded and unbranded third party dealers, and branded and unbranded retail fuel outlets. Sunoco LP branded supply contracts with distributors generally have both time and volume commitments that establish contract duration. These contracts have an initial term of approximately nine years, with an estimated, volume-weighted term remaining of approximately four years.

As part of the asset purchase agreement with 7-Eleven, Sunoco LP and 7-Eleven and SEI Fuel (collectively, the "Distributor") have entered into a 15-year take-or-pay fuel supply agreement in which the Distributor is required to purchase a volume of fuel that provides Sunoco LP a minimum amount of gross profit annually. Sunoco LP expects to recognize this revenue in accordance with the contract as Sunoco LP transfers control of the product to the customer. However, in case of annual shortfall Sunoco LP will recognize the amount payable by the Distributor at the sooner of the time at which the Distributor makes up the shortfall or becomes contractually or operationally unable to do so. The transaction price of the contract is variable in nature, fluctuating based on market conditions. The Partnership has elected to take the practical expedient not to estimate the amount of variable consideration allocated to wholly unsatisfied performance obligations.

In some contractual arrangements, Sunoco LP grants dealers a franchise license to operate Sunoco LP's retail stores over the life of a franchise agreement. In return for the grant of the retail store license, the dealer makes a one-time nonrefundable franchise fee payment to Sunoco LP plus sales based royalties payable to Sunoco LP at a contractual rate during the period of the franchise agreement. Under the requirements of ASC Topic 606, the franchise license is deemed to be a symbolic license for which recognition of revenue over time is the most appropriate measure of progress toward complete satisfaction of the performance obligation. Revenue from this symbolic license is recognized evenly over the life of the franchise agreement.

As of December 31, 2019, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations is $43.59 billion and the Partnership expects to recognize this amount as revenue within the time bands illustrated below:

	Years Ending December 31,				
	2020	2021	2022	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of December 31, 2019	$ 6,232	$ 5,300	$ 4,899	$ 27,158	$ 43,589

Practical Expedients Utilized by the Partnership

The Partnership elected the following practical expedients in accordance with Topic 606:

- *Right to invoice:* The Partnership elected to utilize an output method to recognize revenue that is based on the amount to which the Partnership has a right to invoice a customer for services performed to date, if that amount corresponds directly with the value provided to the customer for the related performance or its obligation completed to date. As such, the Partnership recognized revenue in the amount to which it had the right to invoice customers.
- *Significant financing component:* The Partnership elected not to adjust the promised amount of consideration for the effects of significant financing component if the Partnership expects, at contract inception, that the period between the transfer of a promised good or service to a customer and when the customer pays for that good or service will be one year or less.

- *Unearned variable consideration:* The Partnership elected to only disclose the unearned fixed consideration associated with unsatisfied performance obligations related to our various customer contracts which contain both fixed and variable components.
- *Incremental costs of obtaining a contract:* The Partnership generally expenses sales commissions when incurred because the amortization period would have been less than one year. We record these costs within general and administrative expenses. The Partnership elected to expense the incremental costs of obtaining a contract when the amortization period for such contracts would have been one year or less.
- *Shipping and handling costs:* The Partnership elected to account for shipping and handling activities that occur after the customer has obtained control of a good as fulfillment activities (i.e., an expense) rather than as a promised service.
- *Measurement of transaction price:* The Partnership has elected to exclude from the measurement of transaction price all taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Partnership from a customer (i.e., sales tax, value added tax, etc.).
- *Variable consideration of wholly unsatisfied performance obligations:* The Partnership has elected to exclude the estimate of variable consideration to the allocation of wholly unsatisfied performance obligations.

12. LEASE ACCOUNTING:

Lessee Accounting

The Partnership leases terminal facilities, tank cars, office space, land and equipment under non-cancelable operating leases whose initial terms are typically five to 15 years, with some real estate leases having terms of 40 years or more, along with options that permit renewals for additional periods. At the inception of each, we determine if the arrangement is a lease or contains an embedded lease and review the facts and circumstances of the arrangement to classify lease assets as operating or finance leases under Topic 842. The Partnership has elected not to record any leases with terms of 12 months or less on the balance sheet.

At present, the majority of the Partnership's active leases are classified as operating in accordance with Topic 842. Balances related to operating leases are included in operating lease ROU assets, accrued and other current liabilities, operating lease current liabilities and non-current operating lease liabilities in our consolidated balance sheets. Finance leases represent a small portion of the active lease agreements and are included in finance lease ROU assets, current maturities of long-term debt and long-term debt, less current maturities in our consolidated balance sheets. The ROU assets represent the Partnership's right to use an underlying asset for the lease term and lease liabilities represent the obligation of the Partnership to make minimum lease payments arising from the lease for the duration of the lease term.

Most leases include one or more options to renew, with renewal terms that can extend the lease term from one to 20 years or greater. The exercise of lease renewal options is typically at the sole discretion of the Partnership and lease extensions are evaluated on a lease-by-lease basis. Leases containing early termination clauses typically require the agreement of both parties to the lease. At the inception of a lease, all renewal options reasonably certain to be exercised are considered when determining the lease term. Presently, the Partnership does not have leases that include options to purchase or automatic transfer of ownership of the leased property to the Partnership. The depreciable life of lease assets and leasehold improvements are limited by the expected lease term.

To determine the present value of future minimum lease payments, we use the implicit rate when readily determinable. Presently, because many of our leases do not provide an implicit rate, the Partnership applies its incremental borrowing rate based on the information available at the lease commencement date to determine the present value of minimum lease payments. The operating and finance lease ROU assets include any lease payments made and exclude lease incentives.

Minimum rent payments are expensed on a straight-line basis over the term of the lease. In addition, some leases require additional contingent or variable lease payments, which are based on the factors specific to the individual agreement. Variable lease payments the Partnership is typically responsible for include payment of real estate taxes, maintenance expenses and insurance.

For short-term leases (leases that have term of twelve months or less upon commencement), lease payments are recognized on a straight-line basis and no ROU assets are recorded.

The components of operating and finance lease amounts recognized in the accompanying consolidated balance sheet as of December 31, 2019 were as follows:

	December 31, 2019
Operating leases:	
Lease right-of-use assets, net	$ 935
Operating lease current liabilities	60
Accrued and other current liabilities	1
Non-current operating lease liabilities	901
Finance leases:	
Property, plant and equipment, net	$ 1
Lease right-of-use assets, net	29
Accrued and other current liabilities	1
Current maturities of long-term debt	6
Long-term debt, less current maturities	26
Other non-current liabilities	2

The components of lease expense for the year ended December 31, 2019 were as follows:

	Income Statement Location	Year Ended December 31, 2019
Operating lease costs:		
Operating lease cost	Cost of goods sold	$ 28
Operating lease cost	Operating expenses	73
Operating lease cost	Selling, general and administrative	16
Total operating lease costs		117
Finance lease costs:		
Amortization of lease assets	Depreciation, depletion and amortization	6
Interest on lease liabilities	Interest expense, net of capitalized interest	1
Total finance lease costs		7
Short-term lease cost	Operating expenses	42
Variable lease cost	Operating expenses	17
Lease costs, gross		183
Less: Sublease income	Other revenue	47
Lease costs, net		$ 136

The weighted average remaining lease terms and weighted average discount rates as of December 31, 2019 were as follows:

	December 31, 2019
Weighted-average remaining lease term (years):	
Operating leases	24
Finance leases	5
Weighted-average discount rate (%):	
Operating leases	5 %
Finance leases	5 %

Cash flows and non-cash activity related to leases for the year ended December 31, 2019 were as follows:

	Year Ended December 31, 2019
Operating cash flows from operating leases	$ (159)
Lease assets obtained in exchange for new finance lease liabilities	28
Lease assets obtained in exchange for new operating lease liabilities	40

Maturities of lease liabilities as of December 31, 2019 are as follows:

	Operating leases	Finance leases	Total
2020	$ 104	$ 8	$ 112
2021	96	8	104
2022	83	8	91
2023	77	7	84
2024	74	4	78
Thereafter	1,342	5	1,347
Total lease payments	1,776	40	1,816
Less: present value discount	815	5	820
Present value of lease liabilities	$ 961	$ 35	$ 996

Lessor Accounting

The Partnership leases or subleases a portion of its real estate portfolio to third-party companies as a stable source of long-term revenue. Our lessor and sublease portfolio consists mainly of operating leases with convenience store operators. At this time, most lessor agreements contain five-year terms with renewal options to extend and early termination options based on established terms specific to the individual agreement.

Rental income included in other revenue in our consolidated statement of operations for the year ended December 31, 2019 was $146 million.

Future minimum operating lease payments receivable as of December 31, 2019 are as follows:

	Lease Payments
2020	$ 138
2021	112
2022	75
2023	20
2024	15
Thereafter	12
Total undiscounted cash flows	$ 372

13. DERIVATIVE ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.

We use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. At hedge inception, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract. Changes in the spreads between the forward natural gas prices and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized.

We use futures, swaps and options to hedge the sales price of natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation and storage segment. These contracts are not designated as hedges for accounting purposes.

We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes we retain for fees in our midstream segment whereby our subsidiaries generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price for the residue gas and NGL. These contracts are not designated as hedges for accounting purposes.

We utilize swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs to manage our storage facilities and the purchase and sale of purity NGL. These contracts are not designated as hedges for accounting purposes.

We use 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.

The following table details our outstanding commodity-related derivatives:

	December 31, 2019		December 31, 2018	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	1,483	2020	468	2019
Basis Swaps IFERC/NYMEX[1]	(35,208)	2020-2024	16,845	2019-2020
Options – Puts	—	—	10,000	2019
Power (Megawatt):				
Forwards	3,213,450	2020-2029	3,141,520	2019
Futures	(353,527)	2020	56,656	2019-2021
Options – Puts	51,615	2020	18,400	2019
Options – Calls	(2,704,330)	2020-2021	284,800	2019
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(18,923)	2020-2022	(30,228)	2019-2021
Swing Swaps IFERC	(9,265)	2020	54,158	2019-2020
Fixed Swaps/Futures	(3,085)	2020-2021	(1,068)	2019-2021
Forward Physical Contracts	(13,364)	2020-2021	(123,254)	2019-2020
NGL (MBbls) – Forwards/Swaps	(1,300)	2020-2021	(2,135)	2019
Crude (MBbls) – Forwards/Swaps	4,465	2020	20,888	2019
Refined Products (MBbls) – Futures	(2,473)	2020-2021	(1,403)	2019
Corn (thousand bushels)	(1,210)	2020	(1,920)	2019
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(31,780)	2020	(17,445)	2019
Fixed Swaps/Futures	(31,780)	2020	(17,445)	2019
Hedged Item – Inventory	31,780	2020	17,445	2019

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. To maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We also manage our interest rate exposure by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes:

		Notional Amount Outstanding	
Term	Type [(1)]	December 31, 2019	December 31, 2018
March 2019	Pay a floating rate and receive a fixed rate of 1.42%	$ —	$ 300
July 2019 [(2)]	Forward-starting to pay a fixed rate of 3.56% and receive a floating rate	—	400
July 2020 [(2)(3)]	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	400
July 2022 [(2)]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	400	—

(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.

(3) The July 2020 interest rate swaps were terminated in January 2020.

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.

The Partnership has maintenance margin deposits with certain counterparties in the OTC market, primarily with independent system operators and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on or about the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheets and recognized in net income or other comprehensive income.

Derivative Summary

The following table provides a summary of our derivative assets and liabilities:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 24	$ —	$ —	$ (13)
	24	—	—	(13)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	319	402	(350)	(397)
Commodity derivatives	41	158	(39)	(173)
Interest rate derivatives	—	—	(399)	(163)
	360	560	(788)	(733)
Total derivatives	$ 384	$ 560	$ (788)	$ (746)

The following table presents the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset on the consolidated balance sheets that are subject to enforceable master netting arrangements or similar arrangements:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Derivatives without offsetting agreements	Derivative liabilities	$ —	$ —	$ (399)	$ (163)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	41	158	(39)	(173)
Broker cleared derivative contracts	Other current assets (liabilities)	343	402	(350)	(410)
		384	560	(788)	(746)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(18)	(47)	18	47
Counterparty netting	Other current assets (liabilities)	(318)	(397)	318	397
Total net derivatives		$ 48	$ 116	$ (452)	$ (302)

We disclose the non-exchange traded financial derivative instruments as derivative assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

The following tables summarize the amounts recognized with respect to our derivative financial instruments:

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness		
		Years Ended December 31,		
		2019	2018	2017
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ —	$ (3)	$ 26

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2019	2018	2017
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Revenues	$ (3)	$ —	$ —
Commodity derivatives – Trading	Cost of products sold	21	32	31
Commodity derivatives – Non-trading	Cost of products sold	(78)	(102)	5
Interest rate derivatives	Gains (losses) on interest rate derivatives	(241)	47	(37)
Embedded derivatives	Other, net	—	—	1
Total		$ (301)	$ (23)	$ —

14. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all eligible employees, including those of ETO, Lake Charles LNG, Sunoco LP and USAC. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries made matching contributions of $66 million, $62 million and $59 million to these 401(k) savings plans for the years ended December 31, 2019, 2018 and 2017, respectively.

Pension and Other Postretirement Benefit Plans

Panhandle

Postretirement benefits expense for the years ended December 31, 2019, 2018 and 2017 reflect the impact of changes Panhandle or its affiliates adopted as of September 30, 2013, to modify its retiree medical benefits program, effective January 1, 2014. The modification placed all eligible retirees on a common medical benefit platform, subject to limits on Panhandle’s annual contribution toward eligible retirees’ medical premiums. Prior to January 1, 2013, affiliates of Panhandle offered postretirement health care and life insurance benefit plans (other postretirement plans) that covered substantially all employees. Effective January 1, 2013, participation in the plan was frozen and medical benefits were no longer offered to non-union employees. Effective January 1, 2014, retiree medical benefits were no longer offered to union employees.

Effective January 1, 2018, the plan was amended to extend coverage to a closed group of former employees based on certain criteria.

ETC Sunoco

ETC Sunoco has a plan which provides health care benefits for substantially all of its current retirees. The cost to provide the postretirement benefit plan is shared by ETC Sunoco. and its retirees. Access to postretirement medical benefits was phased out or eliminated for all employees retiring after July 1, 2010. In March, 2012, ETC Sunoco established a trust for its postretirement benefit liabilities. ETC Sunoco made a tax-deductible contribution of approximately $200 million to the trust. The funding of the trust eliminated substantially all of ETC Sunoco’s future exposure to variances between actual results and assumptions used to estimate retiree medical plan obligations.

SemGroup

SemGroup sponsors two defined benefit pension plans and a supplemental defined benefit pension plan (collectively, the “SemGroup Plans”) for certain employees. The SemGroup Plans are closed to new participants and do not accrue any additional benefits.

Obligations and Funded Status

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table contains information at the dates indicated about the obligations and funded status of pension and other postretirement plans on a combined basis:

	December 31, 2019			December 31, 2018		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 1	$ 37	$ 198	$ 1	$ 47	$ 156
Service cost	—	—	1	—	—	1
Interest cost	2	1	7	—	1	5
Amendments	—	—	—	—	—	60
Benefits paid, net	(1)	(7)	(16)	—	(7)	(17)
Actuarial (gain) loss and other	4	—	18	—	(4)	(7)
Settlements	(4)	—	—	—	—	—
SemGroup Acquisition	50	3	—	—	—	—
Benefit obligation at end of period	52	34	208	1	37	198
Change in plan assets:						
Fair value of plan assets at beginning of period	1	—	241	1	—	257
Return on plan assets and other	6	—	35	—	—	(8)
Employer contributions	1	—	10	—	—	9
Benefits paid, net	(1)	—	(16)	—	—	(17)
Settlements	(4)	—	—	—	—	—
SemGroup Acquisition	40	—	—	—	—	—
Fair value of plan assets at end of period	43	—	270	1	—	241
Amount underfunded (overfunded) at end of period	$ 9	$ 34	$ (62)	$ —	$ 37	$ (43)
Amounts recognized in the consolidated balance sheets consist of:						
Non-current assets	$ —	$ —	$ 88	$ —	$ —	$ 68
Current liabilities	—	(5)	(2)	—	(6)	(2)
Non-current liabilities	(9)	(29)	(24)	—	(31)	(23)
	$ (9)	$ (34)	$ 62	$ —	$ (37)	$ 43
Amounts recognized in accumulated other comprehensive income (loss) (pre-tax basis) consist of:						
Net actuarial gain (loss)	$ —	$ 1	$ (5)	$ —	$ 1	$ (7)
Prior service cost	—	—	40	—	—	66
	$ —	$ 1	$ 35	$ —	$ 1	$ 59

The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2019			December 31, 2018		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Projected benefit obligation	$ 51	$ 34	N/A	$ —	$ 37	N/A
Accumulated benefit obligation	52	34	208	1	37	198
Fair value of plan assets	43	—	270	1	—	241

Components of Net Periodic Benefit Cost

	December 31, 2019		December 31, 2018	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Service cost	$ —	$ 1	$ —	$ 1
Interest cost	3	7	1	5
Expected return on plan assets	(2)	(10)	—	(10)
Prior service cost amortization	—	26	—	16
Net periodic benefit cost	$ 1	$ 24	$ 1	$ 12

Assumptions

The weighted-average assumptions used in determining benefit obligations at the dates indicated are shown in the table below:

	December 31, 2019		December 31, 2018	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.00 %	2.71 %	4.02 %	3.40 %
Rate of compensation increase	—	—	N/A	N/A

The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	December 31, 2019		December 31, 2018	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.33 %	3.76 %	3.52 %	3.51 %
Expected return on assets:				
Tax exempt accounts	3.37 %	7.00 %	3.26 %	6.63 %
Taxable accounts	—	4.75 %	N/A	4.50 %
Rate of compensation increase	—	—	N/A	N/A

The long-term expected rate of return on plan assets was estimated based on a variety of factors including the historical investment return achieved over a long-term period, the targeted allocation of plan assets and expectations concerning future returns in the marketplace for both equity and fixed income securities. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to ensure reasonableness and appropriateness.

The assumed health care cost trend weighted-average rates used to measure the expected cost of benefits covered by the plans are shown in the table below:

	December 31,	
	2019	2018
Health care cost trend rate	7.25 %	7.15 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.83 %	4.82 %
Year that the rate reaches the ultimate trend rate	2026	2024

Changes in the health care cost trend rate assumptions are not expected to have a significant impact on postretirement benefits.

Plan Assets

For the Panhandle plans, the overall investment strategy is to maintain an appropriate balance of actively managed investments with the objective of optimizing longer-term returns while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its other postretirement plan asset portfolio, Panhandle has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75%.

The investment strategy of ETC Sunoco funded defined benefit plans is to achieve consistent positive returns, after adjusting for inflation, and to maximize long-term total return within prudent levels of risk through a combination of income and capital appreciation. The objective of this strategy is to reduce the volatility of investment returns and maintain a sufficient funded status of the plans. In anticipation of the pension plan termination, ETC Sunoco targeted the asset allocations to a more stable position by investing in growth assets and liability hedging assets.

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

		Fair Value Measurements at December 31, 2019		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$ 1	$ 1	$ —	$ —
Mutual funds[1]	19	19	—	—
Fixed income securities	23	—	23	—
Total	$ 43	$ 20	$ 23	$ —

(1) Comprised of approximately 100% equities as of December 31, 2019.

		Fair Value Measurements at December 31, 2018		
	Fair Value Total	Level 1	Level 2	Level 3
Mutual funds[1]	$ 1	$ 1	$ —	$ —

(1) Comprised of approximately 100% equities as of December 31, 2018.

The fair value of other postretirement plan assets by asset category at the dates indicated is as follows:

	Fair Value Total	Fair Value Measurements at December 31, 2019		
		Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$ 14	$ 14	$ —	$ —
Mutual funds[1]	177	177	—	—
Fixed income securities	79	—	79	—
Total	$ 270	$ 191	$ 79	$ —

[1] Primarily comprised of approximately 59% equities, 40% fixed income securities and 1% cash as of December 31, 2019.

	Fair Value Total	Fair Value Measurements at December 31, 2018		
		Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$ 20	$ 20	$ —	$ —
Mutual funds[1]	144	144	—	—
Fixed income securities	77	—	77	—
Total	$ 241	$ 164	$ 77	$ —

[1] Primarily comprised of approximately 53% equities, 46% fixed income securities and 1% cash as of December 31, 2018.

The Level 1 plan assets are valued based on active market quotes. The Level 2 plan assets are valued based on the net asset value per share (or its equivalent) of the investments, which was not determinable through publicly published sources but was calculated consistent with authoritative accounting guidelines.

Contributions

We expect to contribute $7 million to pension plans and $8 million to other postretirement plans in 2020. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Panhandle and ETC Sunoco's estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

Years	Pension Benefits - Unfunded Plans [1]	Other Postretirement Benefits (Gross, Before Medicare Part D)
2020	$ 7	$ 20
2021	8	20
2022	8	19
2023	8	18
2024	7	15
2025 - 2029	22	67

[1] Expected benefit payments of funded pension plans are less than $1 million for the next ten years.

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Panhandle does not expect to receive any Medicare Part D subsidies in any future periods.

15. RELATED PARTY TRANSACTIONS:

In June 2017, the Partnership acquired all of the publicly held PennTex common units through a tender offer and exercise of a limited call right, as further discussed in Note 7.

ET-ETO Long-Term Notes

In October 2018, in connection with the Energy Transfer Merger, ET and ETO entered into an intercompany promissory note (“ET-ETO Promissory Note A”) for an aggregate amount up to $2.2 billion that accrues interest at a weighted average rate based on interest payable by ETO on its outstanding indebtedness. The balance outstanding on this note receivable from ET as of December 31, 2018 was $440 million. On August 19, 2019, the entire outstanding balance of $268 million was paid off.

In March 2019, in connection with the ET-ETO senior notes exchange, ET and ETO entered into an intercompany promissory note (“ET-ETO Promissory Note B”) for an aggregate amount up to $4.3 billion that accrues interest at a weighted average rate based on interest payable by ETO on its outstanding indebtedness. The ET-ETO Promissory Note B matures on December 31, 2024. As of December 31, 2019 the ET-ETO Promissory Note B had an outstanding balance of $3.7 billion.

As of December 31, 2019, ETO has a long-term intercompany payable due to ET of $104 million, which has been netted against the outstanding promissory notes receivable in our consolidated balance sheet.

For the year ended December 31, 2019, ETO recognized $184 million in interest income related to these notes, recorded in Other, net on its consolidated statements of operations.

The Partnership also has related party transactions with several of its equity method investees. In addition to commercial transactions, these transactions include the provision of certain management services and leases of certain assets.

The following table summarizes the revenues from related companies on our consolidated statements of operations:

	Years Ended December 31,		
	2019	2018	2017
Revenues from related companies	$ 492	$ 431	$ 303

The following table summarizes the related company accounts receivable and accounts payable balances on our consolidated balance sheets:

	December 31,	
	2019	2018
Accounts receivable from related companies:		
ET	$ 8	$ 65
FGT	50	25
Phillips 66	36	42
Traverse Rover LLC	42	—
Other	31	44
Total accounts receivable from related companies	$ 167	$ 176
Accounts payable to related companies:		
ET	$ —	$ 59
Other	31	60
Total accounts payable to related companies	$ 31	$ 119

16. REPORTABLE SEGMENTS:

Our reportable segments currently reflect the following segments, which conduct their business primarily in the United States:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- NGL and refined products transportation and services;
- crude oil transportation and services;
- investment in Sunoco LP;
- investment in USAC; and
- all other.

Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

The investment in USAC segment reflects the results of USAC beginning April 2018, the date that the Partnership obtained control of USAC.

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation and storage segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our NGL and refined products transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our crude oil transportation and services segment are primarily reflected in crude sales. Revenues from our investment in Sunoco LP segment are primarily reflected in refined product sales. Revenues from our investment in USAC segment are primarily reflected in gathering, transportation and other fees. Revenues from our all other segment are primarily reflected in natural gas sales.

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA as total Partnership 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, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Segment Adjusted EBITDA reflect amounts for unconsolidated affiliates based on the same recognition and measurement methods used to record equity in earnings of unconsolidated affiliates. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA and consolidated Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates. The use of Segment Adjusted EBITDA or Adjusted EBITDA related to unconsolidated affiliates as an analytical tool should be limited accordingly.

The following tables present financial information by segment:

	Years Ended December 31, 2019	2018	2017
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$ 2,749	$ 3,428	$ 2,891
Intersegment revenues	350	309	192
	3,099	3,737	3,083
Interstate transportation and storage:			
Revenues from external customers	1,941	1,664	1,112
Intersegment revenues	22	18	19
	1,963	1,682	1,131
Midstream:			
Revenues from external customers	2,280	2,090	2,510
Intersegment revenues	3,751	5,432	4,433
	6,031	7,522	6,943
NGL and refined products transportation and services:			
Revenues from external customers	9,920	10,119	7,885
Intersegment revenues	1,721	1,004	763
	11,641	11,123	8,648
Crude oil transportation and services:			
Revenues from external customers	18,447	17,236	11,672
Intersegment revenues	—	96	31
	18,447	17,332	11,703
Investment in Sunoco LP:			
Revenues from external customers	16,590	16,982	11,713
Intersegment revenues	6	12	10
	16,596	16,994	11,723
Investment in USAC:			
Revenues from external customers	678	495	—
Intersegment revenues	20	13	—
	698	508	—
All other:			
Revenues from external customers	1,608	2,073	2,740
Intersegment revenues	81	155	161
	1,689	2,228	2,901
Eliminations	(5,951)	(7,039)	(5,609)
Total revenues	$ 54,213	$ 54,087	$ 40,523

	Years Ended December 31,		
	2019	2018	2017
Cost of products sold:			
Intrastate transportation and storage	$ 1,909	$ 2,665	$ 2,327
Midstream	3,577	5,145	4,761
NGL and refined products transportation and services	8,393	8,462	6,508
Crude oil transportation and services	14,832	14,384	9,877
Investment in Sunoco LP	15,380	15,872	10,615
Investment in USAC	91	67	—
All other	1,504	2,006	2,509
Eliminations	(5,885)	(6,998)	(5,580)
Total cost of products sold	$ 39,801	$ 41,603	$ 31,017

	Years Ended December 31,		
	2019	2018	2017
Depreciation, depletion and amortization:			
Intrastate transportation and storage	$ 184	$ 169	$ 147
Interstate transportation and storage	387	334	254
Midstream	1,066	1,006	954
NGL and refined products transportation and services	613	466	401
Crude oil transportation and services	437	445	402
Investment in Sunoco LP	181	167	169
Investment in USAC	231	169	—
All other	37	87	214
Total depreciation, depletion and amortization	$ 3,136	$ 2,843	$ 2,541

	Years Ended December 31,		
	2019	2018	2017
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$ 18	$ 19	$ (156)
Interstate transportation and storage	222	227	236
Midstream	20	26	20
NGL and refined products transportation and services	53	64	33
Crude oil transportation and services	(1)	6	4
All other	(10)	2	7
Total equity in earnings of unconsolidated affiliates	$ 302	$ 344	$ 144

	Years Ended December 31,		
	2019	2018	2017
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 999	$ 927	$ 626
Interstate transportation and storage	1,792	1,680	1,274
Midstream	1,602	1,627	1,481
NGL and refined products transportation and services	2,666	1,979	1,641
Crude oil transportation and services	2,898	2,385	1,328
Investment in Sunoco LP	665	638	732
Investment in USAC	420	289	—
All other	106	76	219
Total Segment Adjusted EBITDA	11,148	9,601	7,301
Depreciation, depletion and amortization	(3,136)	(2,843)	(2,541)
Interest expense, net of interest capitalized	(2,262)	(1,709)	(1,575)
Impairment losses	(74)	(431)	(1,039)
Gains (losses) on interest rate derivatives	(241)	47	(37)
Non-cash compensation expense	(113)	(105)	(99)
Unrealized losses on commodity risk management activities	(5)	(11)	59
Inventory valuation adjustments	79	(85)	24
Losses on extinguishments of debt	(2)	(109)	(42)
Adjusted EBITDA related to unconsolidated affiliates	(626)	(655)	(716)
Equity in earnings of unconsolidated affiliates	302	344	144
Impairment of investments in unconsolidated affiliates	—	—	(313)
Adjusted EBITDA related to discontinued operations	—	25	(223)
Other, net	244	30	154
Income from continuing operations before income tax expense	5,314	4,099	1,097
Income tax expense from continuing operations	(199)	(5)	1,804
Income from continuing operations	5,115	4,094	2,901
Loss from discontinued operations, net of income taxes	—	(265)	(177)
Net income	$ 5,115	$ 3,829	$ 2,724

	December 31,		
	2019	2018	2017
Segment assets:			
Intrastate transportation and storage	$ 6,648	$ 6,365	$ 5,020
Interstate transportation and storage	18,111	15,081	15,316
Midstream	20,332	19,745	20,004
NGL and refined products transportation and services	19,145	18,267	17,600
Crude oil transportation and services	22,933	18,189	17,842
Investment in Sunoco LP	5,438	4,879	8,344
Investment in USAC	3,730	3,775	—
All other and eliminations	5,957	2,308	2,470
Total segment assets	$ 102,294	$ 88,609	$ 86,596

	Years Ended December 31,		
	2019	2018	2017
Additions to property, plant and equipment [1]:			
Intrastate transportation and storage	$ 124	$ 344	$ 175
Interstate transportation and storage	375	812	728
Midstream	827	1,161	1,308
NGL and refined products transportation and services	2,976	2,381	2,971
Crude oil transportation and services	403	474	453
Investment in Sunoco LP	148	103	103
Investment in USAC	200	205	—
All other	215	150	268
Total additions to property, plant and equipment [1]	$ 5,268	$ 5,630	$ 6,006

(1) Excluding acquisitions, net of contributions in aid of construction costs (capital expenditures related to the Partnership's proportionate ownership on an accrual basis).

	December 31,		
	2019	2018	2017
Advances to and investments in unconsolidated affiliates:			
Intrastate transportation and storage	$ 88	$ 83	$ 85
Interstate transportation and storage	2,524	2,070	2,118
Midstream	112	124	126
NGL and refined products transportation and services	461	243	234
Crude oil transportation and services	242	28	22
All other	27	88	113
Total advances to and investments in unconsolidated affiliates	$ 3,454	$ 2,636	$ 2,698

17. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2019:					
Revenues	$ 13,121	$ 13,877	$ 13,495	$ 13,720	$ 54,213
Operating income	1,866	1,828	1,860	1,668	7,222
Net income	1,219	1,282	1,250	1,364	5,115
Net income attributable to partners	950	1,003	977	1,083	4,013

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2018:					
Revenues	$ 11,882	$ 14,118	$ 14,514	$ 13,573	$ 54,087
Operating income	1,067	1,127	1,712	1,551	5,457
Income from continuing operations	776	749	1,491	1,078	4,094
Net income	539	723	1,489	1,078	3,829
Net income attributable to partners	677	421	1,132	850	3,080

18. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

Prior to the Sunoco Logistics Merger, Sunoco Logistics Partners Operations L.P., a subsidiary of Sunoco Logistics was the issuer of multiple series of senior notes that were guaranteed by Sunoco Logistics. Subsequent to the Sunoco Logistics Merger, these notes continue to be guaranteed by Sunoco Logistics.

These guarantees are full and unconditional. For the purposes of this footnote, ETO is referred to as “Parent Guarantor” and Sunoco Logistics Partners Operations L.P. is referred to as “Subsidiary Issuer.” All other consolidated subsidiaries of the Partnership are collectively referred to as “Non-Guarantor Subsidiaries.”

The following supplemental condensed consolidating financial information reflects the Parent Guarantor’s separate accounts, the Subsidiary Issuer’s separate accounts, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations, and the Parent Guarantor’s consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent Guarantor’s investments in its subsidiaries and the Subsidiary Issuer’s investments in its subsidiaries are accounted for under the equity method of accounting.

The consolidating financial information for the Parent Guarantor, Subsidiary Issuer and Non-Guarantor Subsidiaries are as follows:

	December 31, 2019				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ —	$ 288	$ —	$ 288
All other current assets	4,905	44,047	46,287	(88,042)	7,197
Property, plant and equipment	—	—	73,896	—	73,896
Investments in unconsolidated affiliates	57,476	15,045	3,469	(72,536)	3,454
All other assets	5,786	131	11,542	—	17,459
Total assets	$ 68,167	$ 59,223	$ 135,482	$ (160,578)	$ 102,294
Current liabilities	$ 3,394	$ 41,148	$ 48,988	$ (85,811)	$ 7,719
Non-current liabilities	34,782	7,602	14,766	—	57,150
Noncontrolling interests	—	—	8,018	—	8,018
Predecessor equity	—	—	2,025	—	2,025
Total partners’ capital	29,991	10,473	61,685	(74,767)	27,382
Total liabilities and equity	$ 68,167	$ 59,223	$ 135,482	$ (160,578)	$ 102,294

	December 31, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ —	$ 418	$ —	$ 418
All other current assets	4,070	36,889	73,031	(107,893)	6,097
Property, plant and equipment	—	—	66,655	—	66,655
Investments in unconsolidated affiliates	51,876	13,090	2,636	(64,966)	2,636
All other assets	12	75	12,716	—	12,803
Total assets	$ 55,958	$ 50,054	$ 155,456	$ (172,859)	$ 88,609
Current liabilities	$ 3,430	$ 33,517	$ 80,731	$ (108,381)	$ 9,297
Non-current liabilities	24,787	7,605	10,132	—	42,524
Noncontrolling interests	—	—	7,903	—	7,903
Total partners' capital	27,741	8,932	56,690	(64,478)	28,885
Total liabilities and equity	$ 55,958	$ 50,054	$ 155,456	$ (172,859)	$ 88,609

	Year Ended December 31, 2019				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 54,213	$ —	$ 54,213
Operating costs, expenses, and other	—	—	46,991	—	46,991
Operating income	—	—	7,222	—	7,222
Interest expense, net	(1,612)	(374)	(276)	—	(2,262)
Equity in earnings of unconsolidated affiliates	5,623	1,938	302	(7,561)	302
Losses on debt extinguishment	—	—	(2)		(2)
Losses on interest rate derivatives	(241)	—	—	—	(241)
Other, net	314	3	(22)	—	295
Income before income tax expense	4,084	1,567	7,224	(7,561)	5,314
Income tax expense	—	—	199	—	199
Net income	4,084	1,567	7,025	(7,561)	5,115
Less: Net income attributable to noncontrolling interests	—	—	1,051	—	1,051
Less: Net income attributable to redeemable noncontrolling interests	—	—	51	—	51
Net income attributable to partners	$ 4,084	$ 1,567	$ 5,923	$ (7,561)	$ 4,013
Other comprehensive income	$ —	$ —	$ 31	$ —	$ 31
Comprehensive income	4,084	1,567	7,056	(7,561)	5,146
Less: Comprehensive income attributable to noncontrolling interests	—	—	1,051	—	1,051
Less: Comprehensive income attributable to redeemable noncontrolling interests	—	—	51	—	51
Comprehensive income attributable to partners	$ 4,084	$ 1,567	$ 5,954	$ (7,561)	$ 4,044

	Year Ended December 31, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 54,087	$ —	$ 54,087
Operating costs, expenses, and other	—	—	48,630	—	48,630
Operating income	—	—	5,457	—	5,457
Interest expense, net	(1,196)	(176)	(337)	—	(1,709)
Equity in earnings of unconsolidated affiliates	4,170	1,430	344	(5,600)	344
Losses on extinguishments of debt	—	—	(109)	—	(109)
Gains on interest rate derivatives	47	—	—	—	47
Other, net	—	—	69	—	69
Income from continuing operations before income tax expense	3,021	1,254	5,424	(5,600)	4,099
Income tax expense from continuing operations	—	—	5	—	5
Net income from continuing operations	3,021	1,254	5,419	(5,600)	4,094
Loss from discontinued operations, net of income taxes	—	—	(265)	—	(265)
Net income	3,021	1,254	5,154	(5,600)	3,829
Less: Net income attributable to noncontrolling interests	—	—	715	—	715
Less: Net income attributable to redeemable noncontrolling interests	—	—	39	—	39
Less: Net loss attributable to predecessor	—	—	(5)	—	(5)
Net income attributable to partners	$ 3,021	$ 1,254	$ 4,405	$ (5,600)	$ 3,080
Other comprehensive loss	$ —	$ —	$ (43)	$ —	$ (43)
Comprehensive income	3,021	1,254	5,111	(5,600)	3,786
Less: Comprehensive income attributable to noncontrolling interests	—	—	715	—	715
Less: Comprehensive income attributable to redeemable noncontrolling interests	—	—	39	—	39
Less: Comprehensive loss attributable to predecessor	—	—	(5)	—	(5)
Comprehensive income attributable to partners	$ 3,021	$ 1,254	$ 4,362	$ (5,600)	$ 3,037

	Year Ended December 31, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 40,523	$ —	$ 40,523
Operating costs, expenses, and other	—	1	37,808	—	37,809
Operating income (loss)	—	(1)	2,715	—	2,714
Interest expense, net	—	(156)	(1,419)	—	(1,575)
Equity in earnings of unconsolidated affiliates	2,564	1,242	144	(3,806)	144
Impairment of investments in unconsolidated affiliates	—	—	(313)	—	(313)
Losses on extinguishments of debt	—	—	(42)	—	(42)
Losses on interest rate derivatives	—	—	(37)	—	(37)
Other, net	—	—	207	(1)	206
Income from continuing operations before income tax benefit	2,564	1,085	1,255	(3,807)	1,097
Income tax benefit from continuing operations	—	—	(1,804)	—	(1,804)
Net income from continuing operations	2,564	1,085	3,059	(3,807)	2,901
Loss from discontinued operations, net of income taxes	—	—	(177)	—	(177)
Net income	2,564	1,085	2,882	(3,807)	2,724
Less: Net income attributable to noncontrolling interests	—	—	420	—	420
Less: Net income attributable to predecessor	—	—	274	—	274
Net income attributable to partners	$ 2,564	$ 1,085	$ 2,188	$ (3,807)	$ 2,030
Other comprehensive loss	$ —	$ —	$ (5)	$ —	$ (5)
Comprehensive income	2,564	1,085	2,877	(3,807)	2,719
Less: Comprehensive income attributable to noncontrolling interests	—	—	420	—	420
Less: Comprehensive income attributable to predecessor	—	—	274	—	274
Comprehensive income attributable to partners	$ 2,564	$ 1,085	$ 2,183	$ (3,807)	$ 2,025

	Year Ended December 31, 2019				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 3,372	$ 2,732	$ 8,982	$ (6,841)	$ 8,245
Cash flows used in investing activities	(2,044)	(2,732)	(8,462)	6,841	(6,397)
Cash flows used in financing activities	(1,328)	—	(650)	—	(1,978)
Change in cash	—	—	(130)	—	(130)
Cash at beginning of period	—	—	418	—	418
Cash at end of period	$ —	$ —	$ 288	$ —	$ 288

	Year Ended December 31, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 4,041	$ 1,521	$ 5,641	$ (3,644)	$ 7,559
Cash flows used in investing activities	(3,408)	(1,519)	(5,619)	3,644	(6,902)
Cash flows provided by (used in) financing activities	(633)	—	(2,675)	—	(3,308)
Net increase in cash and cash equivalents of discontinued operations	—	—	2,734	—	2,734
Change in cash	—	2	81	—	83
Cash at beginning of period	—	(2)	337	—	335
Cash at end of period	$ —	$ —	$ 418	$ —	$ 418

	Year Ended December 31, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 2,564	$ 1,047	$ 5,013	$ (3,807)	$ 4,817
Cash flows used in investing activities	(2,240)	(1,368)	(5,811)	3,807	(5,612)
Cash flows provided by financing activities	(324)	277	619	—	572
Net decrease in cash and cash equivalents of discontinued operations	—	—	93	—	93
Change in cash	—	(44)	(86)	—	(130)
Cash at beginning of period	—	42	423	—	465
Cash at end of period	$ —	$ (2)	$ 337	$ —	$ 335