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



FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)**
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2026
or
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)**
OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-32740

ENERGY TRANSFER LP

(Exact name of registrant as specified in its charter)

Texas	**30-0108820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

8111 Westchester Drive, Suite 600, Dallas, Texas 75225
(Address of principal executive offices) (zip code)

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

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units	**ET**	**Texas Stock Exchange**
9.250% Series I Fixed Rate Perpetual Preferred Units	**ETprI**	**Texas Stock Exchange**

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

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

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

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

At October 30, 2026, the registrant had 3,444,252,188 common units outstanding.

FORM 10-Q
ENERGY TRANSFER LP AND SUBSIDIARIES
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Definitions

References to the "Partnership" or "Energy Transfer" refer to Energy Transfer LP. In addition, the following is a list of certain acronyms and terms used throughout this document:

/d	per day
AOCI	accumulated other comprehensive income
Bakken Pipeline	Refers collectively to Dakota Access and Energy Transfer Crude Oil Pipeline and/or Energy Transfer Crude Oil Company, LLC, a non-wholly owned subsidiary of Energy Transfer
BBtu	billion British thermal units
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 content
Citrus	Citrus, LLC, a 50/50 joint venture which owns Florida Gas Transmission Company, LLC, which owns the Florida Gas Transmission Pipeline
Common Unitholders	Holders of Energy Transfer common units which represent limited partner interests in the Partnership
Dakota Access	Dakota Access, LLC, a non-wholly owned subsidiary of Energy Transfer and/or Dakota Access Pipeline
Energy Transfer Preferred Units	Collectively, the Series B Preferred Units, Series F Preferred Units, Series G Preferred Units, Series H Preferred Units and Series I Preferred Units
Energy Transfer R&M	Energy Transfer (R&M), LLC (formerly Sunoco (R&M), LLC)
EPA	United States Environmental Protection Agency
ETC Sunoco	ETC Sunoco Holdings LLC (formerly Sunoco, Inc.), a wholly owned subsidiary of Energy Transfer
ETO	Energy Transfer Operating, L.P., formerly a non-wholly owned subsidiary of Energy Transfer until its merger into the Partnership in April 2021
ET-S Permian	ET-S Permian Holdings Company LP, a joint venture between Energy Transfer and Sunoco LP, which owns crude oil and water gathering pipelines and storage assets in the Permian Basin
EURIBOR	Euro Interbank Offered Rate
Exchange Act	Securities Exchange Act of 1934, as amended
Explorer	Explorer Pipeline Company
FERC	United States Federal Energy Regulatory Commission
FIFO	first-in, first-out
GAAP	accounting principles generally accepted in the United States of America
General Partner	LE GP, LLC, the general partner of Energy Transfer
J.C. Nolan	collectively, J.C. Nolan Terminal Co., LLC and J.C. Nolan Pipeline Co., LLC, both of which are joint ventures between Energy Transfer and Sunoco LP, which own a diesel fuel storage terminal in Midland, Texas and a 500-mile diesel fuel pipeline
LIFO	last-in, first-out
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
NGA	Natural Gas Act of 1938
NGL	natural gas liquid, such as propane, butane and natural gasoline
NuStar	NuStar Energy L.P.
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line and/or Panhandle Eastern Pipe Line Company, LP, a wholly owned subsidiary of Energy Transfer
Parkland	Parkland Corporation
Partnership Agreement	Energy Transfer's Agreement of Limited Partnership
PHMSA	Pipeline and Hazardous Materials Safety Administration
Preferred Unitholders	Unitholders of the Series B Preferred Units, Series F Preferred Units, Series G Preferred Units, Series H Preferred Units and Series I Preferred Units, collectively
Rover	Rover Pipeline and/or Rover Pipeline LLC, a non-wholly owned subsidiary of Energy Transfer
SEC	United States Securities and Exchange Commission
Series B Preferred Units	Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series F Preferred Units	Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series G Preferred Units	Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series H Preferred Units	Series H Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series I Preferred Units	Series I Fixed-Rate Perpetual Preferred Units
SESH	Southeast Supply Header, LLC
SPLP	Sunoco Pipeline L.P., a wholly owned subsidiary of Energy Transfer
Sunoco LP	Sunoco LP (TXSE: SUN), a publicly traded partnership and consolidated subsidiary of Energy Transfer
SunocoCorp	SunocoCorp LLC (TXSE: SUNC), a subsidiary which owns all of Sunoco LP's outstanding Class D Units

TanQuid	TanQuid GmbH & Co. KG
Transwestern	Transwestern Pipeline and/or Transwestern Pipeline Company, LLC, a wholly owned subsidiary of Energy Transfer
TXSE	Texas Stock Exchange
USAC	USA Compression Partners, LP (TXSE: USAC), a publicly traded partnership and consolidated subsidiary of Energy Transfer
Vaquero	Vaquero Midstream LLC
White Cliffs	White Cliffs Pipeline, L.L.C.

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	September 30, 2026	December 31, 2025
ASSETS		
Current assets:		
Cash and cash equivalents	$ 926	$ 1,272
Accounts receivable, net	17,231	11,275
Accounts receivable from related companies	276	119
Inventories	4,951	4,770
Income taxes receivable	20	57
Derivative assets	9	52
Other current assets	730	688
Total current assets	24,143	18,233
Property, plant and equipment	147,765	141,283
Accumulated depreciation and depletion	(43,390)	(39,141)
Property, plant and equipment, net	104,375	102,142
Investments in unconsolidated affiliates	3,653	3,589
Lease right-of-use assets, net	1,974	1,841
Other non-current assets, net	2,510	2,591
Intangible assets, net	7,064	7,438
Goodwill	5,667	5,452
Total assets	$ 149,386	$ 141,286

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Dollars in millions)
(unaudited)

	September 30, 2026	December 31, 2025
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 14,076	$ 9,469
Accounts payable to related companies	87	41
Derivative liabilities	37	10
Operating lease current liabilities	218	245
Accrued and other current liabilities	6,428	5,165
Current maturities of long-term debt	12	25
Total current liabilities	20,858	14,955
Long-term debt, less current maturities	68,838	68,308
Non-current operating lease liabilities	1,644	1,515
Deferred income taxes	5,635	5,307
Other non-current liabilities	2,494	1,941
Commitments and contingencies		
Redeemable noncontrolling interests	266	250
Equity:		
Limited Partners:		
Preferred Unitholders	2,480	3,356
Common Unitholders	31,931	30,930
General Partner	(1)	(2)
Accumulated other comprehensive income	32	82
Total partners' capital	34,442	34,366
Noncontrolling interests	15,209	14,644
Total equity	49,651	49,010
Total liabilities and equity	$ 149,386	$ 141,286

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions, except per unit data)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
REVENUES:				
Refined product sales	$ 17,577	$ 5,849	$ 41,691	$ 15,987
Crude sales	8,627	5,296	25,924	15,769
NGL sales	5,730	4,285	16,597	14,427
Gathering, transportation and other fees	3,383	3,126	9,935	9,211
Natural gas sales	1,151	1,015	3,029	3,654
Other	635	383	2,032	1,168
Total revenues	37,103	19,954	99,208	60,216
COSTS AND EXPENSES:				
Cost of products sold	30,531	14,562	78,616	44,079
Operating expenses	1,785	1,532	5,308	4,174
Depreciation, depletion and amortization	1,599	1,440	4,757	4,191
Selling, general and administrative	405	268	1,187	813
Impairment losses	2	1	2	8
Total costs and expenses	34,322	17,803	89,870	53,265
OPERATING INCOME	2,781	2,151	9,338	6,951
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(944)	(890)	(2,825)	(2,564)
Equity in earnings of unconsolidated affiliates	112	116	330	313
Losses on extinguishments of debt	—	(12)	(7)	(31)
Other, net	52	14	—	8
INCOME BEFORE INCOME TAX EXPENSE	2,001	1,379	6,836	4,677
Income tax expense	187	87	516	207
NET INCOME	1,814	1,292	6,320	4,470
Less: Net income attributable to noncontrolling interests	593	259	1,740	918
Less: Net income attributable to redeemable noncontrolling interests	14	14	31	47
NET INCOME ATTRIBUTABLE TO PARTNERS	1,207	1,019	4,549	3,505
Less: General Partner's interest in net income	1	1	4	3
Less: Preferred Unitholders' interest in net income	52	59	170	189
Less: Loss on redemption of preferred units	14	—	14	8
Common Unitholders' interest in net income	$ 1,140	$ 959	$ 4,361	$ 3,305
NET INCOME PER COMMON UNIT:				
Basic	$ 0.33	$ 0.28	$ 1.27	$ 0.96
Diluted	$ 0.33	$ 0.28	$ 1.26	$ 0.96

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in millions)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Net income	$ 1,814	$ 1,292	$ 6,320	$ 4,470
Other comprehensive income (loss), net of tax:				
Change in value of available-for-sale securities	—	5	6	7
Actuarial gain (loss) related to pension and other postretirement benefit plans	—	1	—	(5)
Foreign currency translation adjustments	(18)	(2)	(58)	3
Change in other comprehensive income from unconsolidated affiliates	1	(1)	2	(4)
Total other comprehensive income (loss)	(17)	3	(50)	1
Comprehensive income	1,797	1,295	6,270	4,471
Less: Comprehensive income attributable to noncontrolling interests	593	259	1,740	918
Less: Comprehensive income attributable to redeemable noncontrolling interests	14	14	31	47
Comprehensive income attributable to partners	$ 1,190	$ 1,022	$ 4,499	$ 3,506

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)
(unaudited)

	Common Unitholders	Preferred Unitholders	General Partner	AOCI	Noncontrolling Interests	Total
Balance, December 31, 2025	$ 30,930	$ 3,356	$ (2)	$ 82	$ 14,644	$ 49,010
Distributions to partners	(1,140)	(27)	(1)	—	—	(1,168)
Distributions to noncontrolling interests	—	—	—	—	(545)	(545)
Capital contributions from noncontrolling interests	—	—	—	—	1	1
USAC equity issued for acquisition	—	—	—	—	457	457
Other comprehensive loss, net of tax	—	—	—	(10)	—	(10)
Other, net	20	—	—	—	3	23
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,194	59	1	—	715	1,969
Balance, March 31, 2026	31,004	3,388	(2)	72	15,275	49,737
Distributions to partners	(1,149)	(91)	(1)	—	—	(1,241)
Distributions to noncontrolling interests	—	—	—	—	(523)	(523)
Other comprehensive loss, net of tax	—	—	—	(23)	—	(23)
Other, net	45	—	—	—	7	52
Net income, excluding amounts attributable to redeemable noncontrolling interests	2,027	59	2	—	432	2,520
Balance, June 30, 2026	31,927	3,356	(1)	49	15,191	50,522
Distributions to partners	(1,159)	(42)	(1)	—	—	(1,202)
Distributions to noncontrolling interests	—	—	—	—	(590)	(590)
Capital contributions from noncontrolling interests	—	—	—	—	10	10
Other comprehensive loss, net of tax	—	—	—	(17)	—	(17)
Redemption of preferred units	—	(900)	—	—	—	(900)
Other, net	9	14	—	—	5	28
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,154	52	1	—	593	1,800
Balance, September 30, 2026	$ 31,931	$ 2,480	$ (1)	$ 32	$ 15,209	$ 49,651

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY (continued)
(Dollars in millions)
(unaudited)

	Common Unitholders	Preferred Unitholders	General Partner	AOCI	Noncontrolling Interests	Total
Balance, December 31, 2024	$ 31,195	$ 3,852	$ (2)	$ 73	$ 10,899	$ 46,017
Distributions to partners	(1,105)	(27)	(1)	—	—	(1,133)
Distributions to noncontrolling interests	—	—	—	—	(455)	(455)
Capital contributions from noncontrolling interests	—	—	—	—	2	2
Other comprehensive loss, net of tax	—	—	—	(3)	—	(3)
Other, net	19	—	—	(6)	14	27
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,255	67	1	—	384	1,707
Balance, March 31, 2025	31,364	3,892	(2)	64	10,844	46,162
Distributions to partners	(1,113)	(107)	(1)	—	—	(1,221)
Distributions to noncontrolling interests	—	—	—	—	(479)	(479)
Capital contributions from noncontrolling interests	—	—	—	—	3	3
Other comprehensive income, net of tax	—	—	—	1	—	1
Redemption of Series F Preferred Units	—	(500)	—	—	—	(500)
Conversion of USAC preferred to USAC common units	—	—	—	—	93	93
Other, net	10	8	—	—	19	37
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,099	63	1	—	275	1,438
Balance, June 30, 2025	31,360	3,356	(2)	65	10,755	45,534
Distributions to partners	(1,122)	(27)	(1)	—	—	(1,150)
Distributions to noncontrolling interests	—	—	—	—	(376)	(376)
Capital contributions from noncontrolling interests	—	—	—	—	22	22
Other comprehensive income, net of tax	—	—	—	3	—	3
Other, net	26	—	—	—	7	33
Net income, excluding amounts attributable to redeemable noncontrolling interests	959	59	1	—	259	1,278
Balance, September 30, 2025	$ 31,223	$ 3,388	$ (2)	$ 68	$ 10,667	$ 45,344

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)
(unaudited)

	Nine Months Ended September 30,	
	2026	2025
OPERATING ACTIVITIES:		
Net income	$ 6,320	$ 4,470
Reconciliation of net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	4,757	4,191
Deferred income tax expense	188	68
Inventory valuation adjustments	(445)	(31)
Non-cash compensation expense	137	110
Loss on foreign currency exchange	94	—
Impairment losses	2	8
Other non-cash	(3)	3
Equity in earnings of unconsolidated affiliates	(330)	(313)
Losses on extinguishments of debt	7	31
Distributions from unconsolidated affiliates	199	236
Distributions on unvested awards	(39)	(39)
Net change in operating assets and liabilities, net of effects of acquisitions	784	(483)
Net cash provided by operating activities	11,671	8,251
INVESTING ACTIVITIES:		
Cash paid for J-W Power Company acquisition, net of cash acquired	(445)	—
Cash paid for TanQuid acquisition, net of cash acquired	(194)	—
Cash paid for Delta acquisition, net of cash acquired	(75)	—
Cash paid by Sunoco LP for acquisitions, net of cash received	—	(189)
Cash paid for other acquisitions, net of cash acquired	(87)	(176)
Capital expenditures, excluding allowance for equity funds used during construction	(5,364)	(4,180)
Contributions in aid of construction costs	100	27
Contributions to unconsolidated affiliates	(40)	(5)
Distributions from unconsolidated affiliates in excess of cumulative earnings	114	77
Proceeds from sales of other assets	4	—
Other, net	(24)	19
Net cash used in investing activities	(6,011)	(4,427)
FINANCING ACTIVITIES:		
Proceeds from borrowings	26,320	26,875
Repayments of debt	(26,089)	(23,467)
Sunoco LP Series A preferred units issuance	—	1,473
Redemption of Energy Transfer preferred units	(900)	(500)
Capital contributions from noncontrolling interests	11	27
Capital contributions from redeemable noncontrolling interests	16	—
Distributions to partners	(3,611)	(3,504)
Distributions to noncontrolling interests	(1,658)	(1,310)
Distributions to redeemable noncontrolling interests	(30)	(45)
Debt issuance costs	(80)	(111)
Other, net	15	—
Net cash used in financing activities	(6,006)	(562)
Net change in cash and cash equivalents	(346)	3,262
Cash and cash equivalents, beginning of period	1,272	312
Cash and cash equivalents, end of period	$ 926	$ 3,574

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

ENERGY TRANSFER LP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar and unit amounts, except per unit data, are in millions)
(unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

The consolidated financial statements presented herein contain the results of Energy Transfer LP and its subsidiaries (the "Partnership," "we," "us," "our" or "Energy Transfer").

Basis of Presentation

The unaudited financial information included in this Form 10-Q has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2025, filed with the SEC on February 19, 2026. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All intercompany items and transactions have been eliminated in consolidation. Certain information and disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

The Partnership owns a controlling interest in Sunoco LP. As of September 30, 2026, our interest in Sunoco LP consisted of 100% of the general partner interests and incentive distribution rights, as well as 28.5 million common units. In addition, the Partnership controls SunocoCorp Management LLC, which controls SunocoCorp. SunocoCorp's only cash-generating asset is its investment in all of Sunoco LP's Class D units; the Partnership does not have a beneficial interest in those Class D units.

The Partnership owns a controlling interest in USAC. As of September 30, 2026, our interest in USAC consisted of 100% of the general partner interests and 46.1 million common units of USAC.

The operations of certain pipelines and terminals in which we own an undivided interest are proportionately consolidated in the accompanying consolidated financial statements.

Certain prior period amounts have been reclassified to conform to the current period presentation. These reclassifications had no impact on net income or total equity.

Use of Estimates

The unaudited consolidated financial statements have been prepared in conformity with GAAP, which requires the use of estimates and assumptions made by management that affect the reported amounts of assets, liabilities, revenues, expenses and the accrual for and disclosure of contingent assets and liabilities that exist at the date of the consolidated financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Recent Accounting Pronouncements

In November 2024, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2024-03, *Income Statement–Reporting Comprehensive Income–Expense Disaggregation Disclosures (Subtopic 220-40)*. ASU 2024-03 requires disclosure of specified information about certain costs and expenses in the notes to the consolidated financial statements. ASU 2024-03 is effective for annual periods beginning after December 15, 2026, and interim periods within annual periods beginning after December 15, 2027, with early adoption permitted. ASU 2024-03 is to be applied on a prospective basis, with retrospective application permitted. We are currently evaluating the impact, if any, of ASU 2024-03 on our consolidated financial statements and related disclosures.

2. ACQUISITIONS

Vaquero Acquisition

On October 6, 2026, Energy Transfer entered into a definitive agreement to acquire all the equity interests of Vaquero and related assets for total consideration of approximately $2.63 billion. The transaction consideration will consist of $1.95 billion in cash and approximately 33.3 million newly issued Energy Transfer common units. Vaquero owns and operates natural gas gathering, processing, and transportation assets in the Delaware Basin. The transaction is expected to close in the fourth quarter of 2026, subject to customary closing conditions and regulatory approvals.

Sunoco LP

TanQuid Acquisition

On January 16, 2026, Sunoco LP completed the acquisition of TanQuid for €206 million ($239 million) and assumed debt with a fair value of €298 million ($346 million). TanQuid owns and operates 15 fuel terminals in Germany and one fuel terminal in Poland. The transaction was funded using cash on hand and amounts available under Sunoco LP's credit facility.

The acquisition was recorded using the acquisition method of accounting which requires, among other things, that assets and liabilities assumed be recognized on the balance sheet at their estimated fair values as of the date of acquisition, with any excess purchase price over the fair value of net assets acquired recorded to goodwill. Determining the fair value of acquired assets requires management's judgment and the utilization of a third-party valuation specialist, if applicable, and involves the use of significant estimates and assumptions. Acquired assets were valued based on a combination of the discounted cash flow, the guideline company and the reproduction and replacement methods.

As of the date these financial statements were issued, Sunoco LP's management and the third-party valuation specialist continue to evaluate certain assumptions, which could result in a change to the allocation of the fair value among reporting units or between line items on the consolidated balance sheet, potentially impacting deferred tax balances and/or goodwill. The following table summarizes the preliminary allocation of the purchase price among assets acquired and liabilities assumed.

	As of January 16, 2026
Total current assets	$ 65
Property, plant and equipment, net	639
Lease right-of-use assets, net	59
Other non-current assets, net	1
Total assets	764
Total current liabilities	9
Long-term debt	346
Non-current operating lease liabilities	66
Deferred income taxes	62
Other non-current liabilities	42
Total liabilities	525
Total consideration	239
Cash acquired	45
Total consideration, net of cash acquired	$ 194

Delta Acquisition

On April 1, 2026, Sunoco LP completed the acquisition of Delta Petroleum Group (BVI) Limited ("Delta") for approximately $81 million, excluding cash and net working capital. The purchase price was allocated $36 million to property, plant and equipment, net, $15 million to intangible assets, and $24 million to goodwill. Delta owns and operates terminals and fuel distribution assets across five Caribbean markets. The transaction was funded using cash on hand and amounts available under Sunoco LP's credit facility.

Offen Acquisition by Sunoco LP

On October 27, 2026, Sunoco LP completed the acquisition of Offen Parent, LLC, the parent company of Offen Petroleum Holdings, LLC, in an all-cash transaction for approximately $600 million, plus working capital adjustments. Offen Parent, LLC and its subsidiaries are collectively referred to as "Offen Petroleum." Offen Petroleum operates a U.S.-based fuel distribution network delivering approximately 2.5 billion gallons annually, serving approximately 7,000 customers and over 800 retail stations across the Midwest, Mountain West, and Southwest regions of the U.S.

The acquisition will be recorded using the acquisition method of accounting which requires, among other things, that assets and liabilities assumed be recognized on the balance sheet at their estimated fair values as of the date of acquisition, with any excess purchase price over the fair value of net assets acquired recorded to goodwill. Management, with the assistance of a third-party valuation specialist, is in the process of determining the fair value of assets and liabilities as of the date of

the acquisition. Determining the fair value involves the use of management's judgment as well as the use of significant estimates and assumptions.

Management expects that the purchase price will primarily be allocated to property, plant and equipment, intangible assets, and goodwill; however, as of the date these financial statements were issued, management and the third-party valuation specialist continue to evaluate certain assumptions, which could result in a change to the allocation of the fair value between line items on the consolidated balance sheet, potentially impacting deferred tax balances and/or goodwill.

Other Acquisitions

In the first, second and third quarters of 2026, Sunoco LP completed other acquisitions for total cash consideration of approximately $50 million, $22 million and $15 million, respectively, plus working capital. These transactions were accounted for as asset acquisitions.

USAC

J-W Power Company Acquisition

On January 12, 2026 (the "J-W Acquisition Date"), USAC completed the acquisition of J-W Energy Company ("J-W Energy") and its subsidiary, J-W Power Company ("J-W Power"), a large privately-held provider of compression services in the United States. USAC purchased all of the issued and outstanding capital stock of J-W Energy from Westerman, Ltd. (the "J-W Power Acquisition"). USAC completed the acquisition for total consideration of approximately $912 million, consisting of (i) approximately $455 million in cash and (ii) approximately 18.2 million newly issued USAC common units, which had a fair value on the J-W Acquisition Date of approximately $457 million, with the aggregate payment subject to customary post-closing price adjustments. Upon consummation of the J-W Power Acquisition, J-W Power and J-W Energy became consolidated subsidiaries of USAC.

The J-W Power Acquisition added approximately 0.8 million active horsepower and 1.0 million total horsepower to USAC's fleet across key regions including the Northeast, Mid-Con, Rockies, Gulf Coast, Bakken and Permian Basin. Through the J-W Power Acquisition, USAC also acquired specialized manufacturing facilities that support certain USAC internal compression requirements and those of third-party customers.

The acquisition 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 estimated fair values as of the date of acquisition with any excess purchase price over the fair value of net assets acquired recorded to goodwill. Determining the fair value of acquired assets required management's judgment and the utilization of a third-party valuation specialist, if applicable, and involved the use of significant estimates and assumptions. Acquired assets were valued based on a combination of the discounted cash flow, the guideline company and the reproduction and replacement methods. As of the date these consolidated financial statements were issued, the purchase price allocation is substantially complete; however, certain additional post-closing price adjustments may be made for up to one year following the J-W Acquisition Date.

The following table summarizes the allocation of the purchase price among assets acquired and liabilities assumed.

	At January 12, 2026
Total current assets	$ 135
Property, plant and equipment, net	869
Lease right-of-use assets, net	5
Intangible assets, net [1]	6
Other non-current assets, net	1
Goodwill [2]	117
Total assets	1,133
Total current liabilities	33
Non-current operating lease liabilities	3
Other non-current liabilities	186
Total liabilities	222
Total consideration	911
Cash acquired	11
Total consideration, net of cash acquired	$ 900

[1] Intangible assets, net consisted of approximately $6 million of trade names with a remaining useful life of approximately 3 years.

[2] Goodwill recorded is primarily related to the recognition of deferred tax liabilities arising from acquisition date fair value adjustments with the remainder related to expected commercial and operational synergies, and is subject to change based on final purchase price allocations. None of the goodwill recorded as a result of this transaction is deductible for tax purposes.

3. CASH AND CASH EQUIVALENTS

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. The Partnership's consolidated balance sheets did not include any material amounts of restricted cash as of September 30, 2026 or December 31, 2025.

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

The net change in operating assets and liabilities, net of effects of acquisitions and divestitures, included in the reconciliation of net income to net cash flows provided by operating activities is comprised as follows:

	Nine Months Ended September 30,	
	2026	2025
Accounts receivable	$ (5,928)	$ 305
Accounts receivable from related companies	(172)	(61)
Inventories	234	(200)
Other current assets	—	(11)
Other non-current assets, net	351	(27)
Accounts payable	4,667	(1,016)
Accounts payable to related companies	58	32
Accrued and other current liabilities	1,115	510
Other non-current liabilities	397	(4)
Derivative assets and liabilities, net	62	(11)
Net change in operating assets and liabilities, net of effects of acquisitions	$ 784	$ (483)

Non-cash investing and financing activities were as follows:

	Nine Months Ended September 30,	
	2026	2025
Accrued capital expenditures	$ 1,140	$ 914
Lease assets obtained in exchange for new lease liabilities	189	99
Distribution reinvestment	37	33
USAC exercise and conversion of preferred units into common units	—	93
Sunoco LP common units (noncontrolling interest) issued in connection with acquisitions	—	18
USAC common units (noncontrolling interest) issued in connection with acquisitions	456	—
Common units issued in connection with acquisition	22	—

4. INVENTORIES

Inventories consisted of the following:

	September 30, 2026	December 31, 2025
Natural gas, NGLs and refined products	$ 3,644	$ 3,506
Crude oil	319	286
Spare parts and other	988	978
Total inventories	$ 4,951	$ 4,770

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, except as described below.

Sunoco LP's fuel inventories are stated at the lower of cost or market using the LIFO method, except for certain fuel inventories in the Caribbean as discussed below. As of September 30, 2026 and December 31, 2025, Sunoco LP's fuel inventory balance included lower of cost or market reserves of nil and $472 million, respectively. At September 30, 2026, the replacement cost of Sunoco LP's fuel inventories accounted for using the LIFO method exceeded the carrying value by approximately $395 million.

For the three months ended September 30, 2026 and 2025, the Partnership's cost of products sold included favorable inventory valuation adjustments of $19 million and $10 million, respectively, which increased net income. For the nine months ended September 30, 2026 and 2025, the Partnership's cost of products sold included favorable inventory valuation adjustments of $445 million and $31 million, respectively, which increased net income.

During the three months ended March 31, 2026, Sunoco LP reduced its overall fuel inventories, resulting in a LIFO liquidation. Based on the assumed impact to cost of products sold if the liquidated inventories had been replaced, the effect of the LIFO liquidation was an increase of $102 million to pre-tax income, or $0.03 per common unit (excluding any income tax impact or any assumed changes to distributions) for the nine months ended September 30, 2026, with no impact to the three months ended September 30, 2026. Interim LIFO calculations are based on management's estimates of expected year-end inventory levels and costs; consequently, these interim estimates are subject to changes during the remainder of the year that could impact the final year-end inventory levels or valuation.

Certain of Sunoco LP's fuel inventories in the Caribbean are stated at the lower of cost or market using the first-in, first-out method, under which the cost of fuel sold consists of older acquisition costs, including transportation and storage costs. These FIFO method inventories totaled $179 million and $88 million as of September 30, 2026 and December 31, 2025, respectively.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Commodity derivatives, excluding those designated as normal purchases or normal sales, are recognized as assets or liabilities at fair value on our consolidated balance sheets. Fair value is determined using the highest level of observable inputs available, in accordance with the fair value hierarchy.

Exchange-traded contracts, such as futures, swaps and options, are valued using quoted market prices from exchanges including the New York Mercantile Exchange, Intercontinental Exchange or similar platforms. These are classified as Level 1.

Over-the-counter (OTC) swaps, options and physical forward contracts that are comparable to actively traded instruments are valued using third-party broker quotes, pricing services or relevant exchange data. This category also includes OTC options valued using an option pricing model based on observable market inputs. These instruments are classified as Level 2.

Less liquid instruments, including non-standard term OTC swaps and options, as well as long-dated contracts, are valued using internally developed models based on historical industry practices. These models incorporate forward price curves, volatility assumptions, time value and other relevant economic factors. These are classified as Level 3.

The following tables summarize the gross fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of September 30, 2026 and December 31, 2025 based on inputs used to derive their fair values:

		Fair Value Measurements at September 30, 2026	
	Fair Value Total	Level 1	Level 2
Assets:			
Interest rate derivatives	$ 8	$ —	$ 8
Total commodity derivatives	916	855	61
Other non-current assets	212	212	—
Total assets	$ 1,136	$ 1,067	$ 69
Liabilities:			
Total commodity derivatives	(1,286)	(1,204)	(82)
Total liabilities	$ (1,286)	$ (1,204)	$ (82)

		Fair Value Measurements at December 31, 2025	
	Fair Value Total	Level 1	Level 2
Assets:			
Total commodity derivatives	$ 618	$ 531	$ 87
Other non-current assets	209	209	—
Total assets	$ 827	$ 740	$ 87
Liabilities:			
Total commodity derivatives	$ (454)	$ (404)	$ (50)
Total liabilities	$ (454)	$ (404)	$ (50)

The aggregate estimated fair value and carrying amount of our consolidated debt obligations as of September 30, 2026 were $66.04 billion and $68.85 billion, respectively. As of December 31, 2025, the aggregate fair value and carrying amount of our consolidated debt obligations were $68.55 billion and $68.33 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the respective debt obligations' observable inputs for similar liabilities.

6. NET INCOME PER COMMON UNIT

A reconciliation of the numerators and denominators of the basic and diluted per unit computations is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Net income	$ 1,814	$ 1,292	$ 6,320	$ 4,470
Less: Net income attributable to noncontrolling interests	593	259	1,740	918
Less: Net income attributable to redeemable noncontrolling interests	14	14	31	47
Net income, net of noncontrolling interests	1,207	1,019	4,549	3,505
Less: General Partner's interest in net income	1	1	4	3
Less: Preferred Unitholders' interest in net income	52	59	170	189
Less: Loss on redemption of preferred units	14	—	14	8
Common Unitholders' interest in net income	$ 1,140	$ 959	$ 4,361	$ 3,305
Basic Income per Common Unit:				
Weighted average common units	3,443.6	3,433.0	3,442.2	3,432.2
Basic income per common unit	$ 0.33	$ 0.28	$ 1.27	$ 0.96
Diluted Income per Common Unit:				
Common Unitholders' interest in net income	$ 1,140	$ 959	$ 4,361	$ 3,305
Dilutive effect of equity-based compensation of subsidiaries [1]	—	—	1	—
Diluted income attributable to Common Unitholders	$ 1,140	$ 959	$ 4,360	$ 3,305
Weighted average common units - basic	3,443.6	3,433.0	3,442.2	3,432.2
Dilutive effect of unvested restricted unit awards [1]	23.1	23.1	23.7	23.9
Weighted average common units - diluted	3,466.7	3,456.1	3,465.9	3,456.1
Diluted income per common unit	$ 0.33	$ 0.28	$ 1.26	$ 0.96

[1] Dilutive effects are excluded from the calculation for periods where the impact would have been antidilutive.

7. DEBT OBLIGATIONS

Recent Transactions

Energy Transfer Notes Issuances and Redemptions

In January 2026, the Partnership issued $1.00 billion aggregate principal amount of 4.55% senior notes due 2031, $1.00 billion aggregate principal amount of 5.35% senior notes due 2036 and $1.00 billion aggregate principal amount of 6.30% senior notes due 2056. The Partnership used the net proceeds to refinance existing indebtedness, including to repay commercial paper and borrowings under its Five-Year Credit Facility.

In January 2026, the Partnership redeemed its $1.00 billion aggregate principal amount of 4.75% senior notes due January 2026 using cash on hand and commercial paper borrowings.

In February 2026, the Partnership redeemed its $600 million aggregate principal amount of 5.625% senior notes due May 2027 using cash on hand and commercial paper borrowings.

In July 2026, the Partnership issued $650 million aggregate principal amount of its Series 2026A Junior Subordinated Notes due 2057 (the "Series 2026A notes") and $1.10 billion aggregate principal amount of its Series 2026B Junior Subordinated Notes due 2057 (the "Series 2026B notes"). Initially, the Series 2026A notes will bear interest at an annual rate of 6.550% and the Series 2026B notes will bear interest at an annual rate of 6.700%. The Partnership used the net proceeds to redeem the Series H Preferred Units, to repay borrowings under its Five-Year Credit Facility and for general partnership purposes.

In July 2026, the Partnership redeemed its $550 million aggregate principal amount of 3.90% senior notes due July 2026 using cash on hand and commercial paper borrowings.

Sunoco LP Senior Notes Issuances and Redemption

In March 2026, Sunoco LP issued $600 million aggregate principal amount of 5.375% senior notes due 2031 and $600 million aggregate principal amount of 5.625% senior notes due 2034. These notes will mature on July 15, 2031 and July 15, 2034, respectively, and interest is payable semi-annually on January 15 and July 15 of each year, commencing on July 15, 2026. Sunoco LP used a portion of the net proceeds from this private offering to redeem in full its $500 million aggregate principal amount of 6.000% senior notes due 2026 and its $600 million aggregate principal amount of 6.000% senior notes due 2027.

In March 2026, Sunoco LP redeemed Parkland's remaining senior notes.

In June 2026, Sunoco LP redeemed all of its outstanding 3.875% CAD senior notes due 2026.

In August 2026, Sunoco LP redeemed all of its outstanding 6.000% CAD senior notes due 2028.

USAC Senior Note Issuance

In September 2026, USAC issued $600 million aggregate principal amount of 6.750% senior notes due 2035. These notes will mature on April 1, 2035, and interest is payable semi-annually on April 1 and October 1 of each year, commencing on April 1, 2027.

Credit Facilities and Commercial Paper

Five-Year Credit Facility

The Partnership's revolving credit facility (the "Five-Year Credit Facility") allows for unsecured borrowings up to $5.00 billion until April 11, 2027, and up to $4.84 billion until April 11, 2029. The Five-Year Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased up to $7.00 billion under certain conditions.

As of September 30, 2026, the Five-Year Credit Facility had $565 million of outstanding borrowings, $441 million of which consisted of commercial paper. The amount available for future borrowings was $4.41 billion, after accounting for outstanding letters of credit in the amount of $29 million. The weighted average interest rate on the total amount outstanding as of September 30, 2026 was 4.36%.

Sunoco LP Credit Facility

As of September 30, 2026, Sunoco LP's credit facility, which matures in June 2030, had $111 million of outstanding borrowings, substantially all of which were CAD-denominated, and $84 million in standby letters of credit. The unused availability on Sunoco LP's revolving credit facility as of September 30, 2026 was $2.30 billion. The weighted average interest rate on the total amount outstanding as of September 30, 2026 was 4.35%.

Sunoco LP Receivables Financing Agreement

Upon the closing of Sunoco LP's acquisition of NuStar, the commitments under NuStar's receivables financing agreement were reduced to zero during a suspension period, for which the period end has not been determined. As of September 30, 2026, this facility had no outstanding borrowings. On October 8, 2026, pursuant to a payoff letter with PNC Bank, National Association, as administrative agent, the receivables financing agreement and the related transaction documents were terminated and all related security interests and liens were released.

USAC Credit Facility

As of September 30, 2026, USAC's credit facility, which matures in August 2030, had $684 million of outstanding borrowings and $2 million outstanding letters of credit. As of September 30, 2026, USAC's credit facility had $1.06 billion of remaining unused availability. The weighted average interest rate on the total amount outstanding as of September 30, 2026 was 5.64%.

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 September 30, 2026. For the quarter ended September 30, 2026, the Partnership's leverage ratio, as calculated pursuant to the covenant related to its Five-Year Credit Facility, was 2.83x.

8. REDEEMABLE NONCONTROLLING INTERESTS

Certain redeemable noncontrolling interests in the Partnership's subsidiaries were reflected as mezzanine equity on the consolidated balance sheets.

Redeemable noncontrolling interests consisted of the following:

	September 30, 2026	December 31, 2025
Crestwood Niobrara LLC preferred units	$ 225	$ 225
Other [1]	41	25
Total redeemable noncontrolling interests	$ 266	$ 250

[1] Relates to noncontrolling interest holders in one of the Partnership's consolidated subsidiaries that have the option to sell their interests to the Partnership.

9. EQUITY

Energy Transfer Common Units

Changes in Energy Transfer common units during the nine months ended September 30, 2026 were as follows:

	Number of Units
Number of common units at December 31, 2025	3,440.0
Common units issued under the distribution reinvestment plan	1.8
Common units issued for acquisition	1.1
Common units vested under equity incentive plans and other	1.0
Number of common units at September 30, 2026	3,443.9

Energy Transfer Repurchase Program

During the nine months ended September 30, 2026, Energy Transfer did not repurchase any of its common units under its current buyback program. As of September 30, 2026, $880 million remained available to repurchase under the current program.

Energy Transfer Distribution Reinvestment Program

During the nine months ended September 30, 2026, distributions of $37 million were reinvested under the distribution reinvestment program. As of September 30, 2026, a total of 34.5 million Energy Transfer common units remained available to be issued under currently effective registration statements in connection with the distribution reinvestment program.

Cash Distributions on Energy Transfer Common Units

Distributions declared and/or paid with respect to Energy Transfer common units subsequent to December 31, 2025 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2025	February 6, 2026	February 19, 2026	$ 0.3350
March 31, 2026	May 8, 2026	May 20, 2026	0.3375
June 30, 2026	August 7, 2026	August 19, 2026	0.3400
September 30, 2026	November 6, 2026	November 19, 2026	0.3425

Energy Transfer Preferred Units

As of September 30, 2026 and December 31, 2025, Energy Transfer's outstanding preferred units included 550,000 Series B Preferred Units, 1,484,780 Series G Preferred Units and 41,464,179 Series I Preferred Units. As of December 31, 2025, Energy Transfer's outstanding preferred units also included 900,000 Series H Preferred Units, which were redeemed on August 17, 2026.

The following tables summarize changes in the Energy Transfer Preferred Units:

	Preferred Unitholders				
	Series B	Series G	Series H [1]	Series I	Total
Balance, December 31, 2025	$ 556	$ 1,488	$ 893	$ 419	$ 3,356
Distributions to partners	(18)	—	—	(9)	(27)
Net income	9	26	15	9	59
Balance, March 31, 2026	547	1,514	908	419	3,388
Distributions to partners	—	(53)	(29)	(9)	(91)
Net income	9	27	14	9	59
Balance, June 30, 2026	556	1,488	893	419	3,356
Distributions to partners	(18)	—	(15)	(9)	(42)
Redemption of preferred units	—	—	(900)	—	(900)
Other, net	—	—	14	—	14
Net income	9	26	8	9	52
Balance, September 30, 2026	$ 547	$ 1,514	$ —	$ 419	$ 2,480

[1] The Partnership's Series H Preferred Units were redeemed in August 2026.

	Preferred Unitholders					
	Series B	Series F [1]	Series G	Series H	Series I	Total
Balance, December 31, 2024	$ 556	$ 496	$ 1,488	$ 893	$ 419	$ 3,852
Distributions to partners	(18)	—	—	—	(9)	(27)
Net income	9	8	26	15	9	67
Balance, March 31, 2025	547	504	1,514	908	419	3,892
Distributions to partners	—	(16)	(53)	(29)	(9)	(107)
Redemption of preferred units	—	(500)	—	—	—	(500)
Other, net	—	8	—	—	—	8
Net income	9	4	27	14	9	63
Balance, June 30, 2025	556	—	1,488	893	419	3,356
Distributions to partners	(18)	—	—	—	(9)	(27)
Net income	9	—	27	15	8	59
Balance, September 30, 2025	$ 547	$ —	$ 1,515	$ 908	$ 418	$ 3,388

[1] The Partnership's Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units were redeemed in May 2025.

Cash Distributions on Energy Transfer Preferred Units

Distributions declared on the Energy Transfer Preferred Units were as follows:

Period Ended	Record Date	Payment Date	Series B [2]	Series G [2]	Series H [2]	Series I [1]
December 31, 2025	February 1, 2026	February 15, 2026	$ 33.125	$ —	$ —	$ 0.2111
March 31, 2026	May 1, 2026	May 15, 2026	—	35.630	32.500	0.2111
June 30, 2026	August 3, 2026	August 17, 2026	33.125	—	16.611	0.2111
September 30, 2026	November 4, 2026	November 13, 2026	—	35.630	—	0.2111

[1] The record date and payment date shown above apply to all Energy Transfer Preferred Units, except for the Series I Preferred Units. For the period ended December 31, 2025, the cash distribution on Series I Preferred Units was paid on February 17, 2026 to unitholders of record as of the close of business on February 4, 2026. For the period ended March 31, 2026, the cash distribution on Series I Preferred Units was paid on May 15, 2026 to unitholders of record as of the close of business on May 4, 2026. For the period ended June 30, 2026, the cash distribution on Series I Preferred Units was paid on August 14, 2026 to unitholders of record as of the close of business on August 4, 2026. For the period ended September 30, 2026, the cash distribution on Series I Preferred Units will be paid on November 13, 2026 to unitholders of record as of the close of business on November 4, 2026.

[2] Series B and Series G distributions are currently paid on a semi-annual basis. Distributions on the Series B Preferred Units will begin to be paid quarterly on February 15, 2028. The final distributions on Series H Preferred Units were paid in conjunction with the Series H Preferred Unit redemption on August 17, 2026.

Noncontrolling Interests

The Partnership's consolidated financial statements include noncontrolling interests in SunocoCorp, Sunoco LP and USAC, as well as other non-wholly owned consolidated joint ventures. The following sections describe cash distributions made by our publicly traded subsidiaries, SunocoCorp, Sunoco LP and USAC, all of which are required to distribute all cash on hand (less appropriate reserves determined by the boards of directors of their respective general partners) subsequent to the end of each quarter.

SunocoCorp Cash Distributions

Distributions on SunocoCorp's common units declared and/or paid by SunocoCorp subsequent to December 31, 2025 were as follows:

Quarter Ended	Payment Date	Rate
December 31, 2025	February 19, 2026	$ 0.9317
March 31, 2026	May 20, 2026	0.9899
June 30, 2026	August 19, 2026	1.0023
September 30, 2026	November 19, 2026	1.0148

Sunoco LP Cash Distributions

Distributions on Sunoco LP's common units and Class D Units declared and/or paid by Sunoco LP subsequent to December 31, 2025 were as follows:

Quarter Ended	Payment Date	Rate
December 31, 2025	February 19, 2026	$ 0.9317
March 31, 2026	May 20, 2026	0.9899
June 30, 2026	August 19, 2026	1.0023
September 30, 2026	November 19, 2026	1.0148

Distributions on Sunoco LP's Series A Preferred Units, which are paid semi-annually, were as follows:

Record Date	Payment Date	Rate
March 2, 2026	March 18, 2026	$ 39.375
September 1, 2026	September 18, 2026	39.375

USAC Cash Distributions

Distributions on USAC's common units declared and/or paid by USAC subsequent to December 31, 2025 were as follows:

Quarter Ended	Payment Date	Rate
December 31, 2025	February 6, 2026	$ 0.525
March 31, 2026	May 8, 2026	0.525
June 30, 2026	August 7, 2026	0.525
September 30, 2026	November 6, 2026	0.525

Accumulated Other Comprehensive Income

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

	September 30, 2026	December 31, 2025
Available-for-sale securities	$ 36	$ 30
Foreign currency translation adjustment	(70)	(12)
Actuarial gains related to pensions and other postretirement benefits	54	54
Investments in unconsolidated affiliates, net	12	10
Total AOCI included in partners' capital, net of tax	$ 32	$ 82

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

FERC Proceedings

Rover – FERC – Stoneman House

In late 2016, FERC Enforcement Staff began a non-public investigation related to Rover's purchase and removal of a potentially historic home (known as the Stoneman House) while Rover's application for permission to construct the new 711-mile interstate natural gas pipeline and related facilities was pending. On March 18, 2021, FERC issued an Order to Show Cause and Notice of Proposed Penalty (Docket No. IN19-4-000), ordering Rover to explain why it should not pay a $20 million civil penalty for alleged violations of FERC regulations requiring certificate holders to be forthright in their submissions of information to the FERC. Rover filed its answer and denial to the order on June 21, 2021 and a surreply on September 15, 2021. FERC issued an order on January 20, 2022 setting the matter for hearing before an administrative law judge. The hearing was set to commence on March 6, 2023; as explained below, this FERC proceeding has been stayed.

On February 1, 2022, Energy Transfer and Rover filed a Complaint for Declaratory Relief in the United States District Court for the Northern District of Texas ("USDC") seeking an order declaring that FERC must bring its enforcement action in federal district court (instead of before an administrative law judge). Also on February 1, 2022, Energy Transfer and Rover filed an expedited request to stay the proceedings before the FERC administrative law judge pending the outcome of the USDC case. On May 24, 2022, the USDC ordered a stay of the FERC's enforcement case and the USDC case pending the resolution of two cases pending before the United States Supreme Court. Arguments were heard in those cases on November 7, 2022. On April 14, 2023, the United States Supreme Court held against the government in both cases, finding that the USDC had jurisdiction to hear those suits and to resolve the parties' constitutional challenges. The cases were remanded to the USDC for further proceedings.

On September 13, 2023 the USDC ordered that the USDC case would be stayed pending the resolution of another case pending before the United States Supreme Court and that the FERC enforcement case would remain stayed. On November 13, 2023, the FERC appealed the USDC order to the United States Court of Appeals for the Fifth Circuit (the "Fifth Circuit"). On December 11, 2023, FERC filed a motion to withdraw that appeal, which the Fifth Circuit granted on December 12, 2023. The FERC and USDC proceedings were previously stayed pending resolution of the case pending before the United States Supreme Court. The Supreme Court issued a decision in that case on June 27, 2024. The FERC and USDC proceedings remained stayed at that time. The USDC set a scheduling conference for December 16, 2025. The parties have filed several motions to continue the status conference. On July 22, 2026, the USDC held this matter in abeyance, pending the outcome of settlement discussions between the parties. On October 23, 2026, Rover and the FERC filed a joint motion dismissing Rover's federal lawsuit, without prejudice to refiling, for the purpose of allowing the stay to lift and the Commission to vote to terminate the FERC Stoneman enforcement proceeding. On October 26, 2026, the USDC granted the motion to dismiss, without prejudice. On October 30, 2026, the FERC terminated the in-house proceeding.

Rover – FERC – Tuscarawas

In mid-2017, FERC Enforcement Staff began a non-public investigation regarding allegations that diesel fuel may have been included in the drilling mud at the Tuscarawas River horizontal directional drilling ("HDD") operations. Rover and the Partnership are cooperating with the investigation. In 2019, Enforcement Staff provided Rover with a notice pursuant to Section 1b.19 of the FERC regulations that Enforcement Staff intended to recommend that the FERC pursue an enforcement action against Rover and the Partnership. On December 16, 2021, FERC issued an Order to Show Cause and Notice of Proposed Penalty (Docket No. IN17-4-000), ordering Rover and Energy Transfer to show cause why they should not be found to have violated Section 7(e) of the NGA, Section 157.20 of FERC's regulations, and the Rover Pipeline Certificate Order, and assessed civil penalties of $40 million.

Rover and Energy Transfer filed their answer to this order on March 21, 2022, and Enforcement Staff filed a reply on April 20, 2022. Rover and Energy Transfer filed their surreply to this order on May 13, 2022. FERC has taken no further action on the case since that time.

The primary contractor (and one of the subcontractors) responsible for the HDD operations of the Tuscarawas River site have agreed to indemnify Rover and the Partnership for any and all losses, including any fines and penalties from government agencies, resulting from their actions in conducting such HDD operations. Given the stage of the proceedings, the Partnership is unable at this time to provide an assessment of the potential outcome or range of potential liability, if any; however, the Partnership believes the indemnity described above will be applicable to the penalty proposed by Enforcement Staff and intends to vigorously defend itself against the subject claims.

Other FERC Proceedings

By an order issued on January 16, 2019, the FERC initiated a review of Panhandle's then-existing rates pursuant to Section 5 of the NGA to determine whether the rates 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 NGA. The NGA Section 5 and Section 4 proceedings were consolidated by order of the Chief Judge on October 1, 2019. The initial decision by the administrative law judge was issued on March 26, 2021, and on December 16, 2022, the FERC issued its order on the initial decision. On January 17, 2023, Panhandle and the Michigan Public Service Commission each filed a request for rehearing of FERC's order on the initial decision, which were denied by operation of law as of February 17, 2023. On March 23, 2023, Panhandle appealed these orders to the D.C. Circuit, and the Michigan Public Service Commission also subsequently appealed these orders. On April 25, 2023, the D.C. Circuit consolidated Panhandle's and Michigan Public Service Commission's appeals and stayed the consolidated appeal proceeding while the FERC further considered the requests for rehearing of its December 16, 2022 order. On September 25, 2023, the FERC issued its order addressing arguments raised on rehearing and compliance, which denied our requests for rehearing. Panhandle filed its Petition for Review with the D.C. Circuit regarding the September 25, 2023 order. On October 25, 2023, Panhandle filed a limited request for rehearing of the September 25 order addressing arguments raised on rehearing and compliance, which was subsequently denied by operation of law on November 27, 2023. On November 17, 2023, Panhandle provided refunds to shippers and on November 30, 2023, Panhandle submitted a refund report regarding the consolidated rate proceedings, which was protested by several parties. On January 5, 2024, the FERC issued a second order addressing arguments raised on rehearing in which it modified certain discussion from its September 25, 2023 order and sustained its prior conclusions. Panhandle has timely filed its Petition for Review with the D.C. Circuit regarding the January 5, 2024 order. On May 28, 2024, the FERC issued an order rejecting Panhandle's refund report. On June 27, 2024, Panhandle filed a revised refund report in compliance with the FERC's May 28, 2024 order rejecting Panhandle's refund report and a request for rehearing of the FERC's May 28, 2024 order rejecting Panhandle's refund report, and provided revised refunds to shippers, or in the case of shippers whose revised refunds are less than the original amounts refunded, notices of upcoming debits. One party protested Panhandle's revised refund report, and Panhandle submitted a response to the protest on July 24, 2024. By notice issued July 29, 2024, Panhandle's rehearing request was deemed denied. In an order issued September 9, 2024, FERC addressed arguments raised on rehearing, modified the discussion in the May 28, 2024 order and continued to reach the same result. On September 18, 2024, Panhandle petitioned the D.C. Circuit for review of the September 9, 2024, July 29, 2024, and May 28, 2024 orders. On December 5, 2024, the FERC issued an order rejecting Panhandle's June 27, 2024, refund report, ordering a corrected refund report and directing the issuance of additional refunds. On January 3, 2025, Panhandle submitted an adjusted refund report as well as a request for rehearing of the FERC's December 5, 2024 order. The FERC approved the adjusted refund report by letter order dated January 23, 2025. On February 3, 2025, the FERC issued a Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration. On March 24, 2025, Panhandle petitioned the D.C. Circuit for review of the December 5, 2024 and February 3, 2025 orders. On April 4, 2025, the FERC issued an Order on Rehearing and Clarification. On May 16, 2025, Panhandle petitioned the D.C. Circuit for review of the April 4, 2025 order. On May 19, 2025, the D.C. Circuit consolidated all cases before it and placed the consolidated cases in abeyance pending further order of the D.C. Circuit. On August 12, 2025, the D.C. Circuit issued an order returning all cases to the court's active docket and issued a briefing schedule. Panhandle filed its initial brief on November 10, 2025, FERC filed its brief on February 9, 2026, intervenors filed their brief on February 23, 2026, and Panhandle filed its reply brief on March 16, 2026. Oral argument was held on September 24, 2026.

Commitments

In the normal course of business, Energy Transfer 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. Energy Transfer believes that the terms of these agreements are commercially reasonable and will not have a material adverse effect on the Partnership's financial position or results of operations.

Our joint venture agreements require that we fund our proportionate share of capital contributions to our unconsolidated affiliates. Such contributions will depend upon the 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 following table reflects ROW expense included in operating expenses in the accompanying consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
ROW expense	$ 26	$ 27	$ 58	$ 62

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. Due to the flammable and combustible nature of natural gas and crude oil, the potential exists for personal injury and/or property damage to occur 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.

We or our subsidiaries are parties to various legal proceedings, arbitrations 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 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.

As of September 30, 2026 and December 31, 2025, accruals of approximately $536 million and $324 million, respectively, were reflected on our consolidated balance sheets related to contingent obligations that met both the probable and reasonably estimable criteria. In addition, we may recognize additional contingent losses in the future related to (i) contingent matters for which a loss is currently considered reasonably possible but not probable and/or (ii) losses in excess of amounts that have already been accrued for such contingent matters. In some of these cases, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. For such matters where additional contingent losses can be reasonably estimated, the range of additional losses is estimated to be up to approximately $76 million.

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 or our estimates of reasonably possible losses prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

In addition to the contingent loss amounts disclosed above, we are also party to litigation where contingent gains exist. We and our subsidiaries have recently received favorable verdicts in multiple matters, including against Greenpeace International, et al. and CPS Energy, which total approximately $795 million in the aggregate, including any portions allocable to noncontrolling interests. These contingent gains have not been recorded as of September 30, 2026, because the judgment has not yet been received and/or the matter was still appealable at that date. In October 2026, the appeal period lapsed in the CPS Energy matter; therefore, in October, the Partnership recorded the entire judgment of $393 million, including interest and legal fees (all of which are included in the aggregate $795 million mentioned above).

The following sections include descriptions of certain matters that could impact the Partnership's financial position, results of operations and/or cash flows in future periods. The following sections also include updates to certain matters that have previously been disclosed, even if those matters are not anticipated to have a potentially significant impact on future periods. In addition to the matters disclosed in the following sections, the Partnership is also involved in multiple other matters that could impact future periods, including other lawsuits and arbitration related to the Partnership's commercial agreements. With respect to such matters, contingencies that met both the probable and reasonably estimable criteria have been included in the accruals disclosed above, and the range of additional losses disclosed above also reflects any relevant amounts for such matters.

Dakota Access Pipeline

On July 27, 2016, the Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the U.S. District Court for the District of Columbia (the "D.C. District Court") challenging permits issued by the United States Army Corps of Engineers ("USACE") that allowed 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 that allowed 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 D.C. District Court remanded the case back to the USACE for preparation of an Environmental Impact Statement ("EIS"). On July 6, 2020, the D.C. District Court vacated the easement and ordered the Dakota Access Pipeline to be shut down and emptied of oil by August 5, 2020. Dakota Access and the USACE appealed to the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") 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 D.C. Circuit (1) granted a stay of the portion of the D.C. District Court order that required Dakota Access to shut the pipeline down and empty it of oil, (2) denied a motion to stay the March 25 order pending a decision on the merits by the D.C. Circuit as to whether the USACE would be required to prepare an EIS and (3) denied a motion to stay the D.C. District Court's order to vacate the easement during this appeal process. The August 5 order also states that the D.C. Circuit expected the USACE to clarify its position with respect to whether the USACE intended to allow the continued operation of the pipeline notwithstanding the vacatur of the easement and that the D.C. District Court may consider additional relief, if necessary.

On August 10, 2020, the D.C. District Court ordered the 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, the USACE submitted a status report that indicated that it considered 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. The Tribes subsequently filed a motion seeking an injunction to stop the operation of the pipeline and both the USACE and Dakota Access filed briefs in opposition of the motion for injunction. The motion for injunction was fully briefed as of January 8, 2021.

On January 26, 2021, the D.C. Circuit affirmed the D.C. District Court's March 25, 2020 order requiring an EIS and its July 6, 2020 order vacating the easement. In this same January 26 order, the D.C. Circuit also overturned the D.C. District Court's July 6, 2020 order that the pipeline shut down and be emptied of oil. Dakota Access filed for rehearing en banc on April 12, 2021, which the D.C. Circuit denied. On September 20, 2021, Dakota Access filed a petition with the United States Supreme Court to hear the case. Oppositions were filed by the Solicitor General on December 17, 2021 and the Tribes on December 16, 2021. Dakota Access filed its reply on January 4, 2022. On February 22, 2022, the United States Supreme Court declined to hear the case.

The D.C. District Court scheduled a status conference for February 10, 2021 to discuss the effects of the D.C. Circuit's January 26, 2021 order on the pending motion for injunctive relief, as well as the USACE's expectations as to how it will proceed regarding its enforcement discretion regarding the easement. On May 3, 2021, the USACE advised the D.C. District Court that it had not changed its position with respect to its opposition to the Tribes' motion for injunction. On May 21, 2021, the D.C. District Court denied the plaintiffs' request for an injunction. On June 22, 2021, the D.C. District Court terminated the consolidated lawsuits and dismissed all remaining outstanding counts without prejudice.

On September 8, 2023, the USACE published the Draft EIS. Comments on the Draft EIS were due on December 13, 2023. In December 2025, the USACE issued a Final EIS concluding that the USACE's preferred alternative is that the USACE reissue its easement to DAPL subject to additional easement conditions. The USACE published the Notice of Availability of the Record of Decision ("ROD") in the Federal Register on June 5, 2026. The easement has not yet issued, but is expected to issue in the fourth quarter of 2026. On October 9, 2026, the SRST filed a third complaint in D.C. District Court against Federal defendants USACE and PHMSA, alleging various violations of law relating to the issuance of the December 2025 Final EIS and the May 2026 ROD. Much of this lawsuit is duplicative of the 2016 and 2024 litigations. Dakota Access intends to intervene in this new lawsuit and defend against these claims vigorously. The pipeline continues to operate. Energy Transfer cannot determine when or how future lawsuits will be resolved or the impact they may have on the Bakken Pipeline; however, Energy Transfer expects that after the law and complete record are fully considered, any such proceeding will be resolved in a manner that will allow the pipeline to continue to operate.

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

Standing Rock Sioux Tribe in Federal Court in District of Columbia

In late 2024, the SRST sued the USACE arguing that the USACE's alleged failure to stop Dakota Access from operating violates numerous laws, including the Mineral Leasing Act, the Government Acquisition and Streamlining Act, the National Environmental Policy Act, the Clean Water Act, the National Historic Preservation Act, and the Administrative Procedure Act, as well as the 1868 Fort Laramie Treaty. The SRST requests a permanent injunction or writ of mandamus that would compel the USACE to shut Dakota Access down pending the completion of the USACE's EIS and decision on whether to grant Dakota Access an easement under the Mineral Leasing Act.

On October 15, 2024, the SRST filed the above referenced complaint. A summons to the USACE was issued on October 17, 2024. Dakota Access, the state of North Dakota and numerous other states intervened in the lawsuit in support of the USACE.

On January 17, 2025, the USACE, Dakota Access and state intervenors (including North Dakota and thirteen other states) each filed a motion to dismiss all of the claims in the new SRST litigation. Also, on January 17, 2025, the SRST filed a motion for partial summary judgment on certain of their claims. On March 28, 2025, the D.C. District Court granted the

motions to dismiss. On May 27, 2025, the SRST appealed the dismissal to the D.C. Circuit. On June 23, 2026, the D.C. Circuit dismissed this appeal at the request of the SRST. Dakota Access intends to vigorously defend against this claim.

Williams Antitrust Litigation

On June 28, 2024, Louisiana Energy Gateway LLC, The Williams Companies, Inc., and Williams Fields Services Group, LLC (collectively, "Williams") filed a Petition for Damages against Energy Transfer and Gulf Run Transmission, LLC ("Gulf Run") in the 42nd Judicial District Court, Parish of DeSoto, State of Louisiana ("42nd District Court"), alleging that Energy Transfer and/or Gulf Run have monopolized, conspired to monopolize, and/or attempted to monopolize the relevant product and geographic market for the movement of natural gas from the Haynesville Shale in northwestern Louisiana south to natural gas facilities in the Louisiana Gulf Coast (the "Relevant Market"), engaged in acquisitions that have directly enabled and incentivized Energy Transfer and Gulf Run to substantially lessen competition, and engaged in unfair methods of competition and unfair trade practices.

On September 16, 2024, Energy Transfer and Gulf Run removed the case to the U.S. District Court for the Western District of Louisiana ("Federal Court"). On October 4, 2024, Williams filed a Motion to Remand with the Federal Court, seeking to remand the case back to the 42nd District Court. On October 21, 2024, Energy Transfer and Gulf Run filed a consent to remand based on a subsequent change in circumstances. After the case was remanded, on November 18, 2024, Energy Transfer and Gulf Run filed a Peremptory Exception of No Cause, asserting that Williams failed to state a cause of action. The Peremptory Exception was heard on February 10, 2025 and denied. The 42nd District Court has set the case for trial on June 21, 2027.

Mont Belvieu Incident

On June 26, 2016, a hydrocarbon storage well located on another operator's facility adjacent to Lone Star NGL Mont Belvieu LP's ("Lone Star," now known as Energy Transfer Mont Belvieu NGLs LP) 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 resumed at the facilities in the fall of 2016, with the exception of one of Lone Star's storage wells at the North Terminal that has not been returned to service. Lone Star has obtained payment for most of the losses it has submitted to the adjacent operator. Lone Star continues to quantify and seek reimbursement for outstanding losses.

MTBE Litigation

ETC Sunoco and Energy Transfer R&M (collectively, "Sunoco Defendants") are defendants in lawsuits alleging methyl tertiary butyl ether ("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 September 30, 2026, Sunoco Defendants are defendants in two cases: one case initiated by the State of Maryland and one by the Commonwealth of Pennsylvania. The actions brought also named ETO, ETP Holdco Corporation and Sunoco Partners Marketing & Terminals L.P., now known as Energy Transfer Marketing & Terminals L.P., as defendants. ETP Holdco Corporation and Energy Transfer Marketing & Terminals L.P. are wholly owned subsidiaries of Energy Transfer.

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.

Unitholder Litigation Regarding Pipeline Construction

Various purported unitholders of Energy Transfer have filed derivative actions against various past and current officers and members of Energy Transfer's Board of Directors, LE GP, LLC, and Energy Transfer, as a nominal defendant that assert claims for breach of fiduciary duties, unjust enrichment, waste of corporate assets, breach of Energy Transfer's Partnership Agreement, tortious interference, abuse of control and gross mismanagement related primarily to matters involving the construction of pipelines in Pennsylvania and Ohio. They also seek damages and changes to Energy Transfer's corporate governance structure. See Bettiol v. LE GP, Case No. 3:19-cv-02890-X (N.D. Tex.); Davidson v. Kelcy L. Warren, Cause No. DC-20-02322 (44th Judicial District of Dallas County, Texas); Harris v. Kelcy L. Warren, Case No. 2:20-cv-00364-GAM (E.D. Pa.); Barry King v. LE GP, Case No. 3:20-cv-00719-X (N.D. Tex.); Inter-Marketing Group USA, Inc. v. LE GP, et al., Case No. 2022-0139-SG (Del. Ch.); Elliot v. LE GP LLC, Case No. 3:22-cv-01527-B (N.D. Tex.); Chapa v. Kelcy L. Warren, et al., Index No. 611307/2022 (N.Y. Sup. Ct.); Elliot v. LE GP et al, Cause No. DC-22-14194 (Dallas County, Tex.); and Charles King v. LE GP, LLC et al, Cause No. DC-22-14159 (Dallas County, Texas). The Barry King

action that was filed in the U.S. District Court for the Northern District of Texas (Case No. 3:20-cv-00719-X) has been consolidated with the Bettiol action. On August 9, 2022, the Elliot action that was filed in the U.S. District Court for the Northern District of Texas (Case No. 3:22-cv-01527-B) was voluntarily dismissed. On July 13, 2026, the plaintiffs in the Bettiol action voluntarily dismissed that action without prejudice.

On June 3, 2022, another purported unitholder of Energy Transfer, Mike Vega, filed suit, purportedly on behalf of a class, against Energy Transfer and Messrs. Warren, Long, McCrea and Whitehurst. See Vega v. Energy Transfer LP et al., Case No. 1:22-cv-4614 (S.D.N.Y.). The action asserts claims for violations of Sections 10(b) and 20(a) of the Exchange Act and Rule 10b-5 promulgated thereunder related primarily to statements made in connection with the construction of Rover. On August 10, 2022, the court appointed the New Mexico State Investment Council and Public Employees Retirement Association of New Mexico (the "New Mexico Funds") as lead plaintiffs. New Mexico Funds filed an amended complaint on September 30, 2022 and added as additional defendants Energy Transfer directors John W. McReynolds and Matthew S. Ramsey. On November 7, 2022, the court granted the defendants' motion to transfer and transferred this action to the U.S. District Court for the Northern District of Texas. On January 27, 2023, the defendants filed their motion to dismiss the New Mexico Funds' amended complaint.

The defendants cannot predict the outcome of these lawsuits or any lawsuits that might be filed subsequent to the date of this filing, nor can the defendants predict the amount of time and expense that will be required to resolve these lawsuits. However, the defendants believe that the claims are without merit and intend to vigorously contest them.

Cline Class Action

On July 7, 2017, Perry Cline filed a class action complaint in the Eastern District of Oklahoma (the "Eastern District Court") against Sunoco, Inc. (R&M), (now known as Energy Transfer R&M) and Energy Transfer Marketing & Terminals L.P. (collectively, "ETMT") that alleged ETMT failed to make timely payments of oil and gas proceeds from Oklahoma wells and to pay statutory interest for those untimely payments. On October 3, 2019, the Eastern District Court certified a class to include all persons who received untimely payments from Oklahoma wells on or after July 7, 2012, and who have not already been paid statutory interest on the untimely payments (the "Class"). Excluded from the Class are those entitled to payments of proceeds that qualify as "minimum pay," prior period adjustments and pass through payments, as well as governmental agencies and publicly traded oil and gas companies.

After a bench trial, on August 17, 2020, Judge John Gibney (sitting from the Eastern District of Virginia) issued an opinion that awarded the Class actual damages of $75 million for late payment interest for identified and unidentified royalty owners and interest-on-interest. This amount was later amended to $81 million to account for interest accrued from trial (the "Order"). Judge Gibney also awarded punitive damages in the amount of $75 million. The Class is also seeking attorneys' fees.

On August 27, 2020, ETMT filed its Notice of Appeal with the 10th Circuit Court of Appeals ("10th Circuit") and appealed the entirety of the Order. The matter was fully briefed, and oral argument was set for November 15, 2021. However, on November 1, 2021, the 10th Circuit dismissed the appeal due to jurisdictional concerns with finality of the Order. En banc rehearing of this decision was denied on November 29, 2021. On December 1, 2021, ETMT filed a Petition for Writ of Mandamus to the 10th Circuit to correct the jurisdictional problems and secure final judgment. On February 2, 2022, the 10th Circuit denied the Petition for Writ of Mandamus, citing that there are other avenues for ETMT to obtain adequate relief. On February 10, 2022, ETMT filed a Motion to Modify the Plan of Allocation Order and Issue a Rule 58 Judgment with the trial court, requesting the Eastern District Court to enter a final judgment in compliance with the Rules. ETMT also filed an injunction with the trial court to enjoin all efforts by plaintiffs to execute on any non-final judgment. On March 31, 2022, Judge Gibney denied the Motion to Modify the Plan of Allocation, reiterating his thoughts that the order constitutes a final judgment. Judge Gibney granted the injunction in part (placing a hold on enforcement efforts for 60 days) and denied the injunction in part. The injunction has since been lifted.

Despite the fact that ETMT has taken the position that the judgment is not final and not subject to execution, the Class engaged in asset discovery and actively tried to collect on the judgment through garnishment proceedings from ETMT's customers. ETMT unsuccessfully tried to deposit the funds into the Eastern District Court's Registry. Accordingly, to stop the garnishment proceedings, on December 2, 2022, ETMT wired approximately $161 million to the plaintiff's approved Plan Administrator, which represented at the time the full amount of the judgment with attorneys' fees and post-judgment interest. ETMT did so without waiving its ability to pursue its pending appeal or its right to appeal the merits of the judgment. Plaintiff has since dismissed the garnishment actions.

ETMT appealed the denial of the Motion to Modify to the 10th Circuit in an attempt to get a decision on finality. The appeal was fully briefed, and oral argument was held on March 21, 2023. On August 3, 2023, the 10th Circuit ruled in favor of ETMT and found that the Eastern District Court's plan of allocation (which was part of the final judgment) did not satisfy all finality requirements. The 10th Circuit held that the district court abused its discretion in denying ETMT's Rule 60(b)(6) Motion to Modify and reversed and remanded for further proceedings. The case was sent back to the trial court so

that the Eastern District Court could fix the finality requirements with the judgment. Further, ETMT sought and recovered a return of funds deposited with the Plan Administrator; Class Counsel did not oppose this motion.

At a status hearing on September 28, 2023, Class Counsel indicated that it would seek additional interest up until the date that the final judgment is entered. The Eastern District Court asked for briefing on the issue of additional interest and held a hearing on October 17, 2023 to address this issue further and enter a ruling as to whether additional interest should be added to the judgment total. During the hearing, the Eastern District Court ruled that additional interest should be awarded at the 12% statutory rate from the date of the prior improper judgment up until October 17, 2023. However, the Judge tolled the running of interest for the time period during which the Plan Administrator was in possession of ETMT's funds (between November 2, 2022 and October 10, 2023). Based on this ruling, the Class calculated that approximately $23 million in additional interest should be added to the final judgment. On October 19, 2023, the Eastern District Court entered the new final judgment with a corrected Plan of Allocation. Both parties agree that this newly entered judgment fixes the finality concerns and will allow an appeal to the 10th Circuit on the merits. With the inclusion of additional interest, the total amount awarded to the Class is approximately $104 million in actual damages and $75 million in punitive damages. ETMT appealed the entirety of the judgment to the 10th Circuit. Oral argument took place on November 20, 2024. On November 17, 2025, the 10th Circuit issued its opinion, reversing the issue of punitive damages and affirming the remainder of the Eastern District Court's findings and rulings. Specifically, the 10th Circuit affirmed the Eastern District Court's orders granting class certification and denying post-trial class decertification, along with the orders determining the actual damages awarded to the Class, including pre-judgment interest. The 10th Circuit, however, vacated the $75 million punitive damages award and remanded to the Eastern District Court to amend the judgment consistent with this opinion.

On February 23, 2026, the Eastern District Court judge entered an amended Rule 58 Judgment Order (the "Amended Judgment"), which removed punitive damages from the judgment. The Amended Judgment awarded plaintiffs $104 million in actual damages. Post-judgment interest will also accrue from the date of the prior October 19, 2023 judgment. The parties have also stipulated that attorneys' fees for class counsel would total $5 million if the judgment is ultimately affirmed on appeal.

ETMT appealed the February 23, 2026 final judgment to the 10th Circuit, seeking summary affirmance. The 10th Circuit granted summary affirmance on March 30, 2026.

On February 25, 2026, the Class filed a Motion to Show Cause and Enforce Security Providers' Liability Pursuant to Rule 65.1, asking for an order directing payment of the entire amount of the judgment into the fund established by the Judgment Administrator. The Class argued that the supersedeas bond and parent guaranty expired on their terms and that the full amount of the judgment was due, despite the fact that ETMT timely appealed the Amended Judgment. On May 4, 2026, the Court granted the Class's Motion to Show Cause and directed the security providers to tender the judgment to the Class. As a result, ETMT paid the entirety of the judgment in the amount of $124 million without prejudice to the rights of ETMT to petition to the United States Supreme Court or any of its rights in the event the judgment is reversed or vacated. ETMT's position is that no distributions should be made from the fund until the Supreme Court rules on the petition.

On May 18, 2026, the Class filed a Motion for Sanctions seeking monetary sanctions from ETMT and non-monetary sanctions against one of ETMT's outside counsel. ETMT vigorously defended the sanctions motion, and the motion was ultimately denied on August 26, 2026.

On June 26, 2026, ETMT filed its Petition for Writ of Certiorari to the United States Supreme Court. On October 5, 2026, the Supreme Court denied our cert petition. Given that the judgment has already been paid, the denial of the cert petition brings this matter to conclusion.

Massachusetts Attorney General v. New England Gas Company

On July 7, 2011, the Massachusetts Attorney General (the "MA AG") filed a regulatory complaint with the Massachusetts Department of Public Utilities ("DPU") against New England Gas Company ("NEG") with respect to certain environmental cost recoveries. NEG was an operating division of Southern Union Company ("SUG"), and the NEG assets were acquired in connection with the merger transaction with Energy Transfer in March 2012. Subsequent to the merger, in 2013, SUG sold the NEG assets to Liberty Utilities ("Liberty," and together with NEG and SUG, "Respondents") and retained certain potential liabilities, including the environmental cost recoveries with respect to the pending complaint before the DPU. Specifically, the MA AG seeks a refund to NEG's ratepayers for approximately $18 million in legal fees associated with SUG environmental response activities. The MA AG requests that the DPU initiate an investigation into NEG's collection and reconciliation of recoverable environmental costs, namely: (1) the legal fees charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005; (2) the legal fees charged by the Bishop, London & Dodds firm and passed through the recovery mechanisms since 2005; and (3) the legal fees passed through the recovery mechanism that the MA AG contends only qualify for a lesser (i.e., 50%) level of recovery. Respondents maintain that, by tariff, these costs are recoverable through rates charged to NEG customers pursuant to the environmental remediation adjustment clause program. After the Respondents answered the complaint and

filed a motion to dismiss in 2011, the Hearing Officer deferred decision on the motion to dismiss and issued a stay of discovery pending resolution of a discovery dispute, which it later lifted on June 24, 2013, permitting the case to resume. However, the MA AG failed to take any further steps to prosecute its claims for nearly seven years. The case remained largely dormant until February 2022, when the Hearing Officer denied the motion to dismiss. After receiving input from the parties, the Hearing Officer entered a procedural schedule on March 16, 2022 (which was amended slightly on August 22, 2022). The parties engaged in discovery and the preparation of pre-filed testimony. Respondents submitted their pre-filed testimony on July 11, 2022. The MA AG served three sets of discovery requests on Respondents on September 9, September 12, and September 20, 2022, to which Respondents timely responded. On October 5, 2022, the MA AG requested that the DPU issue a ruling on whether the information that Respondents redacted in their attorneys' fees invoices is protected by the attorney-client privilege. On the same day, the MA AG also filed a Motion to Stay the Procedural Schedule pending a ruling on the privilege issue. On October 6, 2022, without even affording Respondents the opportunity to respond, the DPU granted the MA AG's request to stay the procedural schedule. Accordingly, all previous deadlines (including the MA AG's October 7, 2022, deadline to submit direct pre-filed testimony) are presently stayed. On October 18, 2023, the DPU issued an Order on Attorney General's Motion to Compel, ruling on issues originally raised in a motion to compel that the MA AG filed in 2013. The October 18, 2023 Order directed NEG to review its redactions again and, to the extent any invoices are completely redacted or heavily redacted, to provide more lightly redacted versions within 30 days. The October 18, 2023 Order also stated that the DPU will set a new procedural schedule in this matter sometime after NEG complies with the directives in the order, which Respondents have completed as of January 17, 2024. On January 6, 2026, the Hearing Officer issued a memo requesting substantive briefing on the merits of the matter. On April 23, 2026, the MA AG filed its initial brief. Thereafter, the Hearing Officer granted a series of extensions to the briefing schedule. Liberty and NEG submitted their initial briefs on July 7, 2026. The MA AG filed its reply brief on September 11, 2026. NEG filed its sur-reply on October 8, 2026 (and Liberty filed a letter in lieu of a sur-reply), and we are now awaiting further action from the DPU.

Twin Oaks Pipeline Litigation

On March 27, 2025, Daniel and Katherine La Hart filed a Class Action Complaint against SPLP, Energy Transfer, and Energy Transfer R&M in the Court of Common Pleas of Philadelphia County, captioned Daniel La Hart and Katherine La Hart v. Sunoco Pipeline L.P., Energy Transfer, and Energy Transfer R&M; Case No. 250303655. The action is related to the release of jet fuel (the "Release") from the 14-inch Twin-Oaks to Newark Pipeline (the "Pipeline") in Upper Makefield Township, Bucks County, Pennsylvania. Seven individual actions have also been filed in the Court of Common Pleas of Philadelphia County related to the Release. Plaintiffs in these cases assert causes of action for negligence, gross negligence, negligence per se, strict liability/abnormally dangerous/ultrahazardous activity, strict liability failure to warn, public nuisance, private nuisance, trespass, negligent infliction of emotional distress and medical monitoring. Plaintiffs seek compensatory damages, punitive damages, declaratory and injunctive relief, and medical monitoring for their alleged exposure to petroleum constituents at their properties and in groundwater. The putative class is comprised of homeowners in the surrounding area from September 1, 2023 to present.

On June 25, 2025, Defendants filed their preliminary objections to Plaintiffs' Amended Complaints which included an objection based on improper venue, and on June 27, 2025, Defendants filed a Motion to Transfer the cases to the Court of Common Pleas of Bucks County, Pennsylvania on the grounds of forum non conveniens. On July 9, 2025, Plaintiffs filed a Motion for Preliminary Injunction in the class action, seeking inter alia, to enjoin the operation of the Pipeline, which Defendants opposed on July 21, 2025. In connection with the venue issues raised by these filings, the Court of Common Pleas ordered certain discovery, followed by amended pleadings and/or supplemental briefing. Following this discovery, Plaintiffs filed the current operative complaints on January 15, 2026, which add multiple additional defendants, including Energy Transfer Marketing & Terminals L.P. as well as other defendants who were allegedly shippers of product on the Pipeline and contractors who allegedly worked on the Pipeline. Plaintiffs in the individual actions filed third amended complaints on March 5, 2026, further amending the inclusion of certain contractor and shipper defendants. The Court of Common Pleas has ordered a schedule which provides for additional venue-related discovery and a determination of venue.

Shortly after the original class action complaint was filed, SPLP, Energy Transfer, and Energy Transfer R&M removed the class action to the U.S. District Court for the Eastern District of Pennsylvania (the "E.D. Pa.") on April 24, 2025. On June 13, 2025, the E.D. Pa. granted Plaintiffs' motion to remand the case to the Court of Common Pleas of Philadelphia County. Defendants appealed the remand decision. Following the filing of the second amended class action complaint, the newly added defendants (including Energy Transfer Marketing & Terminals L.P.) removed the class action to E.D. Pa. on February 20, 2026. Plaintiffs moved to remand on March 23, 2026, which Defendants opposed on April 13, 2026. On August 18, 2026, the U.S. Court of Appeals for the Third Circuit vacated the E.D. Pa.'s original remand order, ruling that the district court must re-evaluate whether the alleged conduct of Energy Transfer R&M triggers a Class Action Fairness Act exception to federal jurisdiction.

SPLP, Energy Transfer, Energy Transfer R&M and Energy Transfer Marketing & Terminals intend to vigorously defend these claims.

State of Oklahoma Attorney General – Winter Storm Uri

On April 10, 2024, the State of Oklahoma, through Attorney General Gentner Drummond ("Plaintiff"), filed a petition on behalf of Grand River Dam Authority against defendants ET Gathering & Processing, LLC, successor by merger to Enable Midstream Partners, LP, Enable Oklahoma Intrastate Transmission, LLC, Enable Gas Transmission, LLC and Enable Energy Resources, LLC arising out of Winter Storm Uri in February 2021. Specifically, Plaintiff alleges that defendants violated the Oklahoma Antitrust Reform Act (79 O.S. §201, *et. seq.*) by acting individually and in concert with each other to unreasonably restrain trade in the natural gas market in Oklahoma during the storm. Plaintiff also alleges causes of action for breach of contract, unjust enrichment, fraud, bad faith, conspiracy and negligence. Plaintiff's petition seeks actual damages, punitive damages, treble damages and attorneys' fees and costs. However, the actual amount sought was not specified.

On June 3, 2024, defendants filed a Motion to Dismiss and a Motion to Transfer Venue, along with a Brief in Support. In its Motion to Dismiss, defendants argued that plaintiff's petition fails to state a claim upon which relief can be granted and also that such claims should be dismissed because collateral estoppel bars plaintiff from bringing allegations inconsistent with earlier agency and judicial findings that the extreme cold weather—not defendants' conduct—caused the natural gas shortage and resulting high prices during Winter Storm Uri. Defendants also argued that plaintiff's suit should be dismissed for filing suit in the wrong forum or, alternatively, should be transferred to the correct county of venue (Oklahoma County). Plaintiff filed its response brief on July 12, 2024. A hearing on both motions was held on October 15, 2024. On January 16, 2025, the Judge denied all motions, noting (1) that venue is proper in Osage County, Oklahoma; (2) collateral estoppel does not bar recovery; (3) the plaintiffs can plead inconsistent theories of recovery; and (4) the recovery is public in nature and not foreclosed by statute of limitations. The case then proceeded into the discovery phase.

On February 9, 2026, after significant document discovery was conducted between the parties and the deadline for adding new claims passed in the Court's scheduling order, Plaintiff filed a motion to consolidate this action with two other pending actions, including State of Oklahoma ex rel. Gentner Drummond, Attorney General of Oklahoma vs. Symmetry Energy Solutions, LLC (Case No. CJ-2024-78) and State of Oklahoma ex rel. Gentner Drummond, Attorney General of Oklahoma vs. Symmetry Energy Solutions, LLC, ETC Marketing Ltd., et. al. (Case No. CJ-2025-06) (discussed below), both also pending in the District Court of Osage County, but which are in vastly different procedural stages with different parties and claims. Plaintiff also filed a motion for leave to amend its petition to assert new causes of action against Enable in the pending suit with the aim to consolidate the new claims with the two other pending actions. Enable opposed both the motion for consolidation and motion for leave to amend.

On March 19, 2026, the Court granted the State of Oklahoma's Motion to Consolidate the three pending actions. The Court also granted the State's Motion to Amend its Petition in part, allowing the State the opportunity to amend to add claims under the Oklahoma Antitrust Reform Act, unjust enrichment, and civil conspiracy. However, the Court denied the State the ability to amend to add a claim under the Oklahoma Consumer Protection Act.

On April 29, 2026, the Enable defendants filed a Motion to Dismiss the amended petition filed in the consolidated action based on failure to plead a claim as a matter of law and based on statute of limitations grounds. On May 26, 2026, the Court denied the Motion to Dismiss. The claims against Enable will now move at the pace of the slower docket control order in the other cases. Defendants cannot predict the ultimate outcome of this litigation but will vigorously defend against these claims.

In a separate matter filed on January 9, 2025, the Plaintiff filed a petition against ETC Marketing Ltd. and ETC Marketing Inc. (collectively, "ETCM") and other natural gas marketers in Case No. CJ-25-06 in the District Court of Osage County, Oklahoma, arising out of Winter Storm Uri in February 2021. The Oklahoma Attorney General brought this action on behalf of its state agencies, political subdivisions and the people of the State of Oklahoma. Specifically, Plaintiff alleges that the defendants violated the Oklahoma Antitrust Reform Act (79 O.S. §201, et. seq.) by acting individually and in concert with each other to unreasonably restrain trade in the natural gas market in Oklahoma during the storm. Plaintiff also alleges causes of action for unjust enrichment and violation of the Oklahoma Consumer Protection Act. Plaintiff's petition seeks damages in excess of $75,000, including actual damages, punitive damages, treble damages, and attorneys' fees and costs. However, the actual amount sought was not specified.

On March 17, 2025, all defendants (including ETCM) jointly filed a motion to dismiss and brief in support. In the joint motion to dismiss, defendants asserted that FERC's exclusive jurisdiction preempts all the Attorney General's state-law claims and, alternatively, that the petition does not state a claim under Oklahoma antitrust law. Further, the motion argues that the Oklahoma Consumer Protection Act claims are time-barred and inconsistent with the statute, and that the unjust enrichment claims are barred by Oklahoma law. Finally, the motion alleges that the Attorney General's unjust enrichment claims fail as a matter of law because defendants sold natural gas pursuant to valid contracts and the individual consumers

were not direct purchasers of natural gas from defendants. On August 19, 2025, the court denied the motion without holding oral argument. Then, on July 31, 2026, the joint defendants filed a Motion to Reconsider the Court's August 19, 2025 Order denying Defendants' Motion to Dismiss, or, in the alternative, to certify the Order for interlocutory appeal and stay proceedings based on the Tenth Circuit's July 6, 2026 decision in In re Winter Storm Uri Natural Gas Litigation, which dismissed similar Winter Storm Uri claims filed in Kansas as a matter of law. The Court held that the motion asks for consideration outside the pleadings and, therefore, cannot be considered at the motion to dismiss stage. The Court denied the Motion for Reconsideration and the requested relief to certify for interlocutory appeal on August 21, 2026.

The case is currently in the discovery phase. The above-referenced Enable case filed by the Oklahoma Attorney General is now consolidated into this action.

Defendants cannot predict the ultimate outcome of this litigation but will vigorously defend against these claims.

Marysville – Toledo Pipeline Corrective Action Order

On September 21, 2026, PHMSA issued a Corrective Action Order ("CAO") to Energy Transfer regarding integrity concerns associated with Energy Transfer's hazardous liquid pipeline system. The CAO arises out of a reported release of crude oil from Energy Transfer's Marysville–Toledo Crude Pipeline ("MTS Pipeline") near Macomb County, Michigan. In response to this incident and others, the CAO requires Energy Transfer to undertake various corrective actions, including, among other actions, fulfilling investigation and repair obligations across all hazardous liquid pipeline facilities owned or operated by the Partnership, its subsidiaries, and related entities. Energy Transfer has requested an administrative hearing with PHMSA regarding this matter; however, the agency has delayed the date of this hearing in order to allow the parties to engage in good faith negotiations in an effort to determine a set of corrective measures that address PHMSA's concerns with the Partnership's hazardous liquid pipeline system while minimizing impacts to operations.

Tax Contingencies

Rover Ad Valorem Taxes

Rover appealed the Ohio Department of Taxation (the "Department") final determination of the 2019 Ohio true value of the Rover pipeline to the Ohio Board of Tax Appeals (the "BTA") on September 11, 2020. On March 7, 2024, the BTA remanded the matter to the Department to redetermine the Ohio true value of the Rover pipeline consistent with the opinion of the appraiser the Department engaged for purposes of the BTA hearing. Rover appealed the BTA's order to the Ohio Supreme Court on April 5, 2024, and the court affirmed the BTA's order on August 13, 2025.

Rover timely petitioned the Department's preliminary assessments of its 2020 through 2025 Ohio true values, and these petitions remain pending. If it becomes probable that the Ohio Tax Commissioner's preliminary assessments for tax years 2020 through 2025 are ultimately upheld, then Rover would recognize an additional Ohio public utility personal property tax liability for tax years 2020 through 2025 up to approximately $346 million, including interest. Rover intends to pursue all available legal remedies for the 2020 through 2025 tax years, and Rover cannot predict the outcome of these matters at this time.

On November 10, 2025, Rover filed a complaint against the Ohio Tax Commissioner in the Court of Common Pleas, Franklin County, Ohio. Rover is seeking a declaration that the Tax Commissioner's 2019 valuation approach, if applied to Rover's subsequent tax years, would violate certain protections afforded to Rover under the U.S. Constitution and the Ohio Constitution. The Tax Commissioner filed a motion to dismiss on December 8, 2025, and the motion was denied on March 24, 2026. This matter remains pending, and Rover cannot predict the outcome of this matter at this time.

Sunoco LP New York Motor Fuel Excise Tax Audit

New York State issued a motor fuel excise tax assessment to Sunoco, LLC, a wholly owned subsidiary of Sunoco LP, in the amount of approximately $20 million, exclusive of penalties and interest, for the periods of March 2017 through May 2020. Sunoco, LLC filed an appeal with the New York State Division of Tax Appeals challenging the assessment. Sunoco, LLC cannot predict the outcome of this matter at this time.

USAC Federal Income Tax Audit

On April 13, 2026, USAC settled and closed the IRS' examination of its U.S. federal income tax returns for the years 2019 and 2020.

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 our 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.

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 polychlorinated biphenyls (“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, Inc. that are subject to environmental assessments, including formerly owned terminals and other logistics assets, retail sites that the Partnership no longer operates, closed and/or sold refineries and other formerly owned sites.
- The Partnership 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 September 30, 2026, the Partnership had been named as a PRP at approximately 29 identified or potentially identifiable “Superfund” sites under federal and/or comparable state law. The Partnership is usually one of a number of companies identified as a PRP at a site. The Partnership has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon the Partnership’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 following table 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.

	September 30, 2026	December 31, 2025
Current	$ 93	$ 62
Non-current	407	354
Total environmental liabilities	$ 500	$ 416

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 three and nine months ended September 30, 2026, the Partnership recorded $6 million and $19 million, respectively, of expenditures related to environmental cleanup programs. During the three and nine months ended September 30, 2025, the Partnership recorded $19 million and $26 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 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 the Federal Occupational Safety and Health Act (“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; however, there is no assurance that such costs will not be material in the future.

11. REVENUE

Disaggregation of Revenue

The Partnership’s consolidated financial statements reflect eight reportable segments, which also represent the level at which the Partnership aggregates revenue for disclosure purposes. Note 13 depicts the disaggregation of revenue by segment.

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 minimum fee, but allow 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 presents the opening and closing balances of Sunoco LP's and USAC's contract assets for the periods presented:

	Contract Assets	Accounts receivable from contracts with customers
December 31, 2025	$ 480	$ 1,757
September 30, 2026	591	3,743
Increase (decrease)	$ 111	$ 1,986
December 31, 2024	$ 288	$ 1,167
September 30, 2025	344	1,339
Increase (decrease)	$ 56	$ 172

The following tables summarize the consolidated activity of our contract liabilities:

	Contract Liabilities
Balance, December 31, 2025	$ 745
Additions	502
Revenue recognized	(499)
Balance, September 30, 2026	$ 748
Balance, December 31, 2024	$ 759
Additions	838
Revenue recognized	(954)
Balance, September 30, 2025	$ 643

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 components of the contracts are included in the following table.

As of September 30, 2026, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations was $37.59 billion. The Partnership expects to recognize this amount as revenue within the time bands illustrated in the following table:

	Years Ending December 31,				
	2026 (remainder)	2027	2028	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of September 30, 2026	$ 2,381	$ 7,556	$ 6,136	$ 21,513	$ 37,586

12. DERIVATIVE ASSETS AND LIABILITIES

Commodity Price Risk

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

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

We use futures, swaps and options to hedge the sales price of natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales in 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 natural gas, 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 intrastate 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 intrastate 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:

	September 30, 2026		December 31, 2025	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
Natural Gas (BBtu)	(100,553)	2026-2028	(233,645)	2026-2028
Power (Megawatt)	(1,435,071)	2026-2033	(461,896)	2026-2029
Crude, NGL and refined products (MBbls)	(25,719)	2026-2029	(59,247)	2026-2029
Other	various	2026-2027	various	2026-2042
Fair Value Hedging Derivatives				
Natural Gas (BBtu)	(87,170)	2026-2027	(100,346)	2026

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 interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

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

Term	Type [1]	Notional Amount Outstanding September 30, 2026
Sunoco LP:		
December 2030 [2]	Pay an average fixed rate of 2.5095% and receive a floating rate	$ 216

[1] Floating rates are based on EURIBOR.

[2] The December 2030 interest rate swap was acquired in conjunction with Sunoco LP's TanQuid acquisition in 2026, with a notional amount of €191 million ($216 million).

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.

Our natural gas transportation and midstream revenues are derived significantly from companies that engage in exploration and production activities. In addition to oil and gas producers, the Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrial end-users, 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 is 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	
	September 30, 2026	December 31, 2025	September 30, 2026	December 31, 2025
Derivatives designated as hedging instruments:				
Commodity derivatives – margin deposits	$ 14	$ 31	$ (7)	$ (2)
	14	31	(7)	(2)
Derivatives not designated as hedging instruments:				
Commodity derivatives – margin deposits	841	485	(1,190)	(392)
Commodity derivatives	61	102	(89)	(60)
Interest rate derivatives	8	—	—	—
	910	587	(1,279)	(452)
Total derivatives	$ 924	$ 618	$ (1,286)	$ (454)

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	September 30, 2026	December 31, 2025	September 30, 2026	December 31, 2025
Derivatives without offsetting agreements	Other non-current assets, net	$ 8	$ —	$ —	$ —
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	61	102	(89)	(60)
Broker cleared derivative contracts	Other current assets (liabilities)	855	516	(1,197)	(394)
Total gross derivatives		924	618	(1,286)	(454)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(52)	(50)	52	50
Counterparty netting	Other current assets (liabilities)	(812)	(384)	812	384
Total net derivatives		$ 60	$ 184	$ (422)	$ (20)

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 table summarizes the location and amounts recognized in our consolidated statements of operations with respect to our derivative financial instruments:

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2026	2025	2026	2025
Derivatives not designated as hedging instruments:					
Commodity derivatives	Cost of products sold	$ (315)	$ 10	$ (466)	$ 114
Interest rate derivatives	Other, net	7	—	9	—
Total		$ (308)	$ 10	$ (457)	$ 114

13. REPORTABLE SEGMENTS

Our reportable segments, which conduct their business primarily in the United States, 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;
- investment in USAC; and
- all other.

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

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation and storage segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our NGL and refined products transportation and services segment are primarily reflected in NGL sales and gathering, transportation 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 and in gathering, transportation and other fees. 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 and gathering, transportation and other fees.

We report Segment Adjusted EBITDA (defined below) as the measure of segment performance reviewed by our chief operating decision maker ("CODM"). The role of the CODM is held by the Partnership's co-chief executive officers ("co-CEOs"). Both of the co-CEOs fulfill specific functions that impact the allocation of resources and assessment of performance among our reportable segments, including the approval of budgets and the evaluation of growth projects and acquisitions. The Partnership's co-CEOs receive and review the same information with respect to the Partnership's segment operating results.

The co-CEOs use Segment Adjusted EBITDA to allocate resources (including employees, property, and financial or capital resources) for each segment predominantly in the annual budget and forecasting process. The co-CEOs also use Segment Adjusted EBITDA to assess the performance for each segment and in the compensation of certain employees. The co-CEOs consider forecast-to-actual variances on a monthly basis when making decisions about allocating capital and personnel to the segments. Assets by segment are not a measure used to assess our performance by the co-CEOs and thus are not reported in our disclosures.

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, certain foreign currency transaction gains and losses, other non-operating income or expense items and certain non-recurring gains and losses. Inventory valuation adjustments that are excluded from the calculation of Adjusted EBITDA represent only the changes in lower of cost or market reserves on inventory that is carried at LIFO. These amounts are unrealized valuation adjustments applied to Sunoco LP's fuel volumes remaining in inventory at the end of the period.

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.

The following tables present financial information by segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 980	$ 773	$ 2,503	$ 2,739
Intersegment revenues	101	96	330	355
	1,081	869	2,833	3,094
Interstate transportation and storage:				
Revenues from external customers	609	595	1,835	1,792
Intersegment revenues	11	8	28	22
	620	603	1,863	1,814
Midstream:				
Revenues from external customers	901	819	2,652	2,560
Intersegment revenues	3,008	2,173	7,122	7,223
	3,909	2,992	9,774	9,783
NGL and refined products transportation and services:				
Revenues from external customers	6,290	4,919	18,399	15,982
Intersegment revenues	1,343	934	3,626	2,721
	7,633	5,853	22,025	18,703
Crude oil transportation and services:				
Revenues from external customers	9,407	6,043	28,203	17,996
Intersegment revenues	7	—	20	3
	9,414	6,043	28,223	17,999
Investment in Sunoco LP:				
Revenues from external customers	17,976	6,023	42,906	16,586
Intersegment revenues	53	9	72	15
	18,029	6,032	42,978	16,601
Investment in USAC:				
Revenues from external customers	347	234	973	698
Intersegment revenues	11	17	58	48
	358	251	1,031	746
All other:				
Revenues from external customers	593	548	1,737	1,863
Intersegment revenues	318	375	793	991
	911	923	2,530	2,854
Eliminations	(4,852)	(3,612)	(12,049)	(11,378)
Total	$ 37,103	$ 19,954	$ 99,208	$ 60,216

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Cost of products sold:				
Intrastate transportation and storage	$ 661	$ 546	$ 1,503	$ 2,071
Interstate transportation and storage	3	3	10	8
Midstream	2,512	1,746	5,578	5,917
NGL and refined products transportation and services	6,351	4,493	17,762	14,769
Crude oil transportation and services	8,425	5,047	24,983	14,986
Investment in Sunoco LP	16,469	5,386	38,265	14,733
Investment in USAC	34	34	96	112
All other	923	895	2,419	2,799
Eliminations	(4,847)	(3,588)	(12,000)	(11,316)
Total	$ 30,531	$ 14,562	$ 78,616	$ 44,079

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Operating expenses, excluding non-cash compensation, amortization, accretion and other non-cash expenses:				
Intrastate transportation and storage	$ 75	$ 72	$ 215	$ 190
Interstate transportation and storage	216	271	661	681
Midstream	485	459	1,444	1,296
NGL and refined products transportation and services	313	294	895	771
Crude oil transportation and services	245	243	699	693
Investment in Sunoco LP	380	180	1,195	500
Investment in USAC	99	43	279	133
All other	5	17	18	18
Eliminations	(53)	(65)	(157)	(158)
Total	$ 1,765	$ 1,514	$ 5,249	$ 4,124

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Depreciation, depletion and amortization:				
Intrastate transportation and storage	$ 59	$ 52	$ 162	$ 154
Interstate transportation and storage	144	144	433	427
Midstream	476	457	1,415	1,364
NGL and refined products transportation and services	262	249	777	745
Crude oil transportation and services	271	294	807	775
Investment in Sunoco LP	280	159	848	469
Investment in USAC	89	71	265	212
All other	18	14	50	45
Total	$ 1,599	$ 1,440	$ 4,757	$ 4,191

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Selling, general and administrative expenses, excluding non-cash compensation and accretion expenses:				
Intrastate transportation and storage	$ 13	$ 12	$ 41	$ 36
Interstate transportation and storage	35	29	99	92
Midstream	54	48	160	151
NGL and refined products transportation and services	47	41	143	130
Crude oil transportation and services	38	36	84	118
Investment in Sunoco LP	143	47	449	130
Investment in USAC	30	14	90	42
All other	14	11	31	37
Total	$ 374	$ 238	$ 1,097	$ 736

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Equity in earnings of unconsolidated affiliates [1]:				
Intrastate transportation and storage	$ 5	$ 4	$ 15	$ 12
Interstate transportation and storage	76	73	222	208
Midstream	2	8	7	14
NGL and refined products transportation and services	16	22	53	59
Crude oil transportation and services	7	8	19	17
All other	6	1	14	3
Total	$ 112	$ 116	$ 330	$ 313

[1] Amounts reflected above exclude Sunoco LP's earnings from the ET-S Permian and J.C. Nolan joint ventures, which are eliminated in consolidation.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Other segment items [1]:				
Intrastate transportation and storage	$ 14	$ (9)	$ 86	$ 61
Interstate transportation and storage	134	131	407	380
Midstream	6	12	43	25
NGL and refined products transportation and services	302	29	470	32
Crude oil transportation and services	165	29	117	18
Investment in Sunoco LP	12	70	(180)	163
Investment in USAC	3	—	14	—
All other	5	(8)	(8)	5
Eliminations	(46)	(56)	(164)	(159)
Total	$ 595	$ 198	$ 785	$ 525

[1] Other segment items include, if applicable to a segment, Adjusted EBITDA related to unconsolidated affiliates and other income and expense items. The amounts reflected above include the reversal of unrealized gains and losses, because such amounts are included in cost of products sold in the table above but are excluded from Segment Adjusted EBITDA. For the investment in Sunoco LP segment, this also includes inventory valuation adjustments.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Additions to property, plant and equipment [1]:				
Intrastate transportation and storage	$ 322	$ 431	$ 1,234	$ 930
Interstate transportation and storage	221	110	674	235
Midstream	421	416	1,206	1,149
NGL and refined products transportation and services	400	328	1,009	1,076
Crude oil transportation and services	133	115	347	272
Investment in Sunoco LP	237	157	638	418
Investment in USAC	107	47	206	110
All other	83	34	215	188
Total	$ 1,924	$ 1,638	$ 5,529	$ 4,378

(1) Amounts are presented on the accrual basis, net of contributions in aid of construction costs. Amounts exclude acquisitions and include only the Partnership's proportionate share of capital expenditures related to joint ventures.

	September 30, 2026	December 31, 2025
Investments in unconsolidated affiliates [1]:		
Intrastate transportation and storage	$ 161	$ 151
Interstate transportation and storage	2,393	2,353
Midstream	127	130
NGL and refined products transportation and services	376	362
Crude oil transportation and services	189	190
Investment in Sunoco LP	342	342
All other	65	61
Total	$ 3,653	$ 3,589

(1) Amounts reflected above exclude Sunoco LP's investments in the ET-S Permian and J.C. Nolan joint ventures, which are eliminated in consolidation.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$ 346	$ 230	$ 1,160	$ 858
Interstate transportation and storage	500	431	1,500	1,413
Midstream	864	751	2,635	2,444
NGL and refined products transportation and services	1,224	1,054	3,695	3,065
Crude oil transportation and services	871	746	2,574	2,220
Investment in Sunoco LP	1,049	489	2,889	1,401
Investment in USAC	198	160	580	459
All other	(21)	(23)	1	(58)
Adjusted EBITDA (consolidated)	$ 5,031	$ 3,838	$ 15,034	$ 11,802

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Reconciliation of net income to Adjusted EBITDA:				
Net income	$ 1,814	$ 1,292	$ 6,320	$ 4,470
Depreciation, depletion and amortization	1,599	1,440	4,757	4,191
Interest expense, net of interest capitalized	944	890	2,825	2,564
Income tax expense	187	87	516	207
Impairment losses	2	1	2	8
Non-cash compensation expense	49	40	137	110
Unrealized (gains) losses on commodity risk management activities	379	(1)	519	(32)
Inventory valuation adjustments (Sunoco LP)	(19)	(10)	(445)	(31)
Losses on extinguishments of debt	—	12	7	31
Adjusted EBITDA related to unconsolidated affiliates	196	193	588	542
Equity in earnings of unconsolidated affiliates	(112)	(116)	(330)	(313)
Other, net	(8)	10	138	55
Adjusted EBITDA (consolidated)	$ 5,031	$ 3,838	$ 15,034	$ 11,802

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with (i) our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q; and (ii) the consolidated financial statements and management's discussion and analysis of financial condition and results of operations included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2025 filed with the SEC on February 19, 2026. 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 "Part I – Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2025 filed with the SEC on February 19, 2026, in "Part II - Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2026 filed with the SEC on May 7, 2026 and in the Current Report on Form 8-K12B filed with the SEC on July 6, 2026. Additional information on forward-looking statements is discussed in "Forward-Looking Statements."

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "Energy Transfer" mean Energy Transfer LP and its consolidated subsidiaries.

RECENT DEVELOPMENTS

Acquisitions

Vaquero Acquisition

On October 6, 2026, Energy Transfer entered into a definitive agreement to acquire all the equity interests of Vaquero and related assets for total consideration of approximately $2.63 billion. The transaction consideration will consist of $1.95 billion in cash and approximately 33.3 million newly issued Energy Transfer common units. Vaquero owns and operates natural gas gathering, processing, and transportation assets in the Delaware Basin. The transaction is expected to close in the fourth quarter of 2026, subject to customary closing conditions and regulatory approvals.

TanQuid Acquisition by Sunoco LP

On January 16, 2026, Sunoco LP completed the acquisition of TanQuid for €206 million ($239 million) and assumed debt with a fair value of €298 million ($346 million). TanQuid owns and operates 15 fuel terminals in Germany and one fuel terminal in Poland. The transaction was funded using cash on hand and amounts available under Sunoco LP's credit facility.

Delta Acquisition by Sunoco LP

On April 1, 2026, Sunoco LP completed the acquisition of Delta Petroleum Group (BVI) Limited ("Delta") for approximately $81 million, excluding cash and net working capital. Delta owns and operates terminals and fuel distribution assets across five Caribbean markets. The transaction was funded using cash on hand and amounts available under Sunoco LP's credit facility.

Offen Acquisition by Sunoco LP

On October 27, 2026, Sunoco LP completed the acquisition of Offen Parent, LLC, the parent company of Offen Petroleum Holdings, LLC, in an all-cash transaction for approximately $600 million, plus working capital adjustments. Offen Parent, LLC and its subsidiaries are collectively referred to as "Offen Petroleum." Offen Petroleum operates a U.S.-based fuel distribution network delivering approximately 2.5 billion gallons annually, serving approximately 7,000 customers and over 800 retail stations across the Midwest, Mountain West, and Southwest regions of the U.S.

Other Sunoco LP Acquisitions

In the first, second and third quarters of 2026, Sunoco LP completed other acquisitions for total cash consideration of approximately $50 million, $22 million and $15 million, respectively, plus working capital. These transactions were accounted for as asset acquisitions.

J-W Power Company Acquisition by USAC

On January 12, 2026 (the "J-W Acquisition Date"), USAC completed the acquisition of J-W Energy Company ("J-W Energy") and its subsidiary, J-W Power Company ("J-W Power"), a large privately-held provider of compression services in the United States. USAC purchased all of the issued and outstanding capital stock of J-W Energy from Westerman, Ltd. (the "J-W Power Acquisition"). USAC completed the acquisition for total consideration of approximately $912 million, consisting of (i) approximately $455 million in cash and (ii) approximately 18.2 million newly issued USAC common units, which had a fair value on the J-W Power Acquisition date of approximately $457 million, subject to customary post-closing price adjustments. Upon consummation of the J-W Power Acquisition, J-W Power and J-W Energy became consolidated subsidiaries of USAC.

The J-W Power Acquisition added approximately 0.8 million active horsepower and 1.0 million total horsepower to USAC's fleet across key regions including the Northeast, Mid-Con, Rockies, Gulf Coast, Bakken and Permian Basin. J-W Power also owns and operates specialized manufacturing facilities that support its internal compression requirements and those of third-party customers.

Quarterly Cash Distribution

In October 2026, Energy Transfer announced a quarterly distribution of $0.3425 per unit ($1.37 annualized) on Energy Transfer common units for the quarter ended September 30, 2026.

Regulatory Update

Interstate Natural Gas Transportation Regulation

Rate Regulation

Effective January 2018, the 2017 Tax Cuts 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 clarified that a pipeline organized as a master limited partnership will not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs. On July 31, 2020, the United States Court of Appeals for the District of Columbia Circuit issued an opinion upholding the FERC's decision denying a separate master limited partnership recovery of an income tax allowance and its decision not to require the master limited partnership to refund accumulated deferred income tax balances. In light of the rehearing order's clarification regarding an individual entity's ability to argue in support of recovery of an income tax allowance and the court's subsequent opinion upholding denial of an income tax allowance to a master limited partnership, the impact of the FERC's policy on the treatment of income taxes on the rates we can charge for FERC-regulated transportation services is unknown at this time.

Even without application of the FERC's ratemaking-related policy statements and rulemakings, 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, including return on equity and tax-related components, but also other pipeline costs that will continue to affect FERC's determination of just and reasonable cost-of-service rates. 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 Tiger Pipeline, Midcontinent Express Pipeline and Fayetteville Express Pipeline, 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 Florida Gas Transmission Pipeline, Transwestern and Panhandle, have a mix of tariff rate, discount rate and negotiated rate agreements. 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 changes to FERC policies, 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 our cost-of-service components and the outcomes of any challenges to our rates by the FERC or our shippers.

On July 18, 2018, the FERC issued a final rule establishing procedures to evaluate rates charged by the FERC-jurisdictional gas pipelines in light of the Tax Act and the FERC's Revised Policy Statement. By an order issued on January 16, 2019, the FERC initiated a review of Panhandle's then-existing rates pursuant to Section 5 of the NGA to determine whether the rates 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 NGA. The NGA Section 5 and Section 4 proceedings were consolidated by order of the Chief Judge on October 1, 2019. The initial decision by the administrative law judge was issued on March 26, 2021, and on December 16, 2022, the FERC issued its order on the initial decision. On January 17, 2023, Panhandle and the Michigan Public Service Commission each filed a request for rehearing of FERC's order on the initial decision, which were denied by operation of law as of February 17, 2023. On March 23, 2023, Panhandle appealed these orders to the D.C. Circuit, and the Michigan Public Service Commission also subsequently appealed these orders. On April 25, 2023, the D.C. Circuit consolidated Panhandle's and Michigan Public Service Commission's appeals and stayed the consolidated appeal proceeding while the FERC further considered the requests for rehearing of its December 16, 2022 order. On September 25, 2023, the FERC issued its order addressing arguments raised on rehearing and compliance, which denied our requests for rehearing. Panhandle filed its Petition for Review with the D.C. Circuit regarding the September 25, 2023 order. On October 25, 2023, Panhandle filed a

limited request for rehearing of the September 25 order addressing arguments raised on rehearing and compliance, which was subsequently denied by operation of law on November 27, 2023. On November 17, 2023, Panhandle provided refunds to shippers and on November 30, 2023, Panhandle submitted a refund report regarding the consolidated rate proceedings, which was protested by several parties. On January 5, 2024, the FERC issued a second order addressing arguments raised on rehearing in which it modified certain discussion from its September 25, 2023 order and sustained its prior conclusions. Panhandle has timely filed its Petition for Review with the D.C. Circuit regarding the January 5, 2024 order. On May 28, 2024, the FERC issued an order rejecting Panhandle's refund report. On June 27, 2024, Panhandle filed a revised refund report in compliance with the FERC's May 28, 2024 order rejecting Panhandle's refund report and a request for rehearing of the FERC's May 28, 2024 order rejecting Panhandle's refund report, and provided revised refunds to shippers, or in the case of shippers whose revised refunds are less than the original amounts refunded, notices of upcoming debits. One party protested Panhandle's revised refund report, and Panhandle submitted a response to the protest on July 24, 2024. By notice issued July 29, 2024, Panhandle's rehearing request was deemed denied. In an order issued September 9, 2024, FERC addressed arguments raised on rehearing, modified the discussion in the May 28, 2024 order and continued to reach the same result. On September 18, 2024, Panhandle petitioned the D.C. Circuit for review of the September 9, 2024, July 29, 2024, and May 28, 2024 orders. On December 5, 2024, the FERC issued an order rejecting Panhandle's June 27, 2024, refund report, ordering a corrected refund report and directing the issuance of additional refunds. On January 3, 2025, Panhandle submitted an adjusted refund report as well as a request for rehearing of the FERC's December 5, 2024 order. The FERC approved the adjusted refund report by letter order dated January 23, 2025. On February 3, 2025, the FERC issued a Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration. On March 24, 2025, Panhandle petitioned the D.C. Circuit for review of the December 5, 2024 and February 3, 2025 orders. On April 4, 2025, the FERC issued an Order on Rehearing and Clarification. On May 16, 2025, Panhandle petitioned the D.C. Circuit for review of the April 4, 2025 order. On May 19, 2025, the D.C. Circuit consolidated all cases before it and placed the consolidated cases in abeyance pending further order of the D.C. Circuit. On August 12, 2025, the D.C. Circuit issued an order returning all cases to the court's active docket and issued a briefing schedule. Panhandle filed its initial brief on November 10, 2025, FERC filed its brief on February 9, 2026, intervenors filed their brief on February 23, 2026, and Panhandle filed its reply brief on March 16, 2026. Oral argument was held on September 24, 2026.

Pipeline Certification

The FERC issued a Notice of Inquiry ("NOI") on April 19, 2018, 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. On February 18, 2021, the FERC issued another NOI ("2021 NOI"), reopening its review of the 1999 Policy Statement. Comments on the 2021 NOI were due on May 26, 2021; we filed comments in the FERC proceeding. In September 2021, FERC issued a Notice of Technical Conference on Greenhouse Gas Mitigation related to natural gas infrastructure projects authorized under Sections 3 and 7 of the Natural Gas Act of 1938. A technical conference was held on November 19, 2021, and post-technical conference comments were submitted to the FERC on January 7, 2022.

On February 18, 2022, the FERC issued two new policy statements: (1) an Updated Policy Statement on the Certification of New Interstate Natural Gas Facilities ("2022 Certificate Policy Statement") and (2) a Policy Statement on the Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews ("GHG Policy Statement"), to be effective that same day. On March 24, 2022, the FERC issued an order designating the 2022 Certificate Policy Statement and the GHG Policy Statement as draft policy statements, and requested further comments. The FERC stated that it will not apply the now draft policy statements to pending applications or applications to be filed at FERC until it issues any final guidance on these topics. Comments on the 2022 Certificate Policy Statement and GHG Policy Statement were due on April 25, 2022, and reply comments were due on May 25, 2022. On January 24, 2025, the FERC issued an order withdrawing the draft GHG Policy Statement and terminating the proceeding. On September 12, 2025, the FERC issued an order withdrawing the draft 2022 Certificate Policy Statement and terminating the proceeding.

Interstate Common Carrier Regulation

Liquids pipelines transporting in interstate commerce are regulated by FERC as common carriers under the Interstate Commerce Act ("ICA"). Under the ICA, 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 for Finished Goods, or PPI-FG. Many existing pipelines utilize the FERC liquids index to change transportation rates annually. 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.

In December 2020, FERC issued an order setting the indexed rate at the Producer Price Index for Finished Goods (PPI-FG) plus 0.78% during the five-year period commencing July 1, 2021 and ending June 30, 2026. The FERC received requests for rehearing of its December 17, 2020 order and on January 20, 2022, granted rehearing and modified the oil index. Specifically, for the five-year period commencing July 1, 2021 and ending June 30, 2026, FERC-regulated liquids pipelines charging indexed rates were permitted to adjust their indexed ceilings annually by PPI-FG minus 0.21%. FERC directed liquids pipelines

to recompute their ceiling levels for July 1, 2021 through June 30, 2022, as well as the ceiling levels for the period July 1, 2022 through June 30, 2023, based on the new index level. Where an oil pipeline's filed rates exceeded its ceiling levels, FERC ordered such oil pipelines to reduce the rate to bring it into compliance with the recomputed ceiling level to be effective March 1, 2022. Some parties sought rehearing of the January 20, 2022 order with FERC, which was denied by FERC on May 6, 2022. Certain parties appealed the January 20 and May 6 orders. On July 26, 2024, the D.C. Circuit ruled in LEPA v. FERC that FERC violated the Administrative Procedure Act because the January 20, 2022 order modified the index without following notice and comment. As a result, the D.C. Circuit vacated the January 20, 2022 order and on September 17, 2024, the Commission reinstated the index level established by its original December 17, 2020 order, directed pipelines to file an informational filing to show their recomputed ceiling levels reflecting the reinstated index level and stated that pipelines could file to prospectively increase their indexed rates to their recomputed levels. On October 17, 2024, FERC issued a Supplemental Notice of Proposed Rulemaking ("Supplemental NOPR") that proposed a reduction to the then-effective index by one percent.

On November 20, 2025, FERC withdrew the Supplemental NOPR and confirmed that the PPI-FG plus 0.78% index established in its December 17, 2020 order would remain in effect through June 30, 2026. On the same day, FERC issued an Order Denying Rehearing of the Reinstatement Order and Granting Remedial Relief ("Remedial Relief Order"), which granted remedial relief to liquids pipelines for the period of March 1, 2022 to September 17, 2024 (the "Locked-In Period"), when the lower index was effective under the order vacated by the D.C. Circuit in LEPA v. FERC, but only if such pipelines charged the maximum rate allowed under the applicable index ceiling during the relevant time period. On October 15, 2026, in response to requests for clarification, FERC issued an order clarifying that pipelines that charged less than the maximum rate during the Locked-In Period may also recover remedial amounts in certain circumstances, and that pipelines eligible for remedial relief may collect interest on those amounts. FERC also denied a motion to stay the Remedial Relief Order pending judicial review. Court appeals of the Remedial Relief Order remain pending.

Also on November 20, 2025, the FERC issued a Notice of Proposed Rulemaking on the 2026 Five-Year Oil Pipeline Index ("2026 Index NOPR"), proposing to use the Producer Price Index for Finished Goods (PPI-FG) minus 1.42% as the index level beginning July 1, 2026 to June 30, 2031. The NOPR proceeded through the standard notice-and-comment process, with comments submitted in late 2025 and early 2026.

On December 18, 2025, the Commission issued an Order Denying Petition for Emergency Relief ("Emergency Relief Order Denial"), which denied a petition requesting emergency relief from invoices issued by a liquid pipeline company to recover amounts of indexed rates for the Locked-In Period and explained that, consistent with the Remedial Relief Order, pipelines that charged the maximum rates permitted under the Commission's now-vacated January 20, 2022 rehearing order during the Locked-In Period may invoice shippers to recover the amounts that would have been chargeable under the December 17, 2020 order.

In January 2026, multiple shippers filed petitions for review at the D.C. Circuit challenging FERC's November 20, 2025 orders, including, the (i) Remedial Relief Order, (ii) Order Terminating Supplemental NOPR, and (iii) Emergency Relief Order Denial. These appeals are pending.

On April 24, 2026, the FERC issued an order setting the indexed rate at PPI-FG minus 0.55% during the five-year period commencing July 1, 2026 through June 30, 2031 ("Index Order"). Following issuance of the final rule on April 24, 2026, shippers and other parties filed petitions for review with the D.C. Circuit challenging the Index Order. Those petitions are pending.

Separately, on December 15, 2022, the FERC had issued a Proposed Policy Statement on Oil Pipeline Affiliate Committed Service, which addressed whether a contract for committed transportation service complies with the ICA where the only shipper to obtain the committed service is an affiliate of the regulated entity. The proposed policy statement would have created a rebuttable presumption that affiliate contracts are unduly discriminatory and not just and reasonable in certain circumstances and required a pipeline to produce additional evidentiary support for affiliate contract rates and terms. On February 19, 2026, the FERC withdrew the proposed policy statement on the basis that the record contained insufficient evidence of discriminatory open season terms and conditions to merit an industry-wide policy statement. FERC noted, however, that it would continue to address issues related to affiliated-only committed service in individual proceedings.

On May 21, 2026, the FERC issued a notice of proposed rulemaking to revise its blanket certificate regulations to expand the scope and scale of projects that interstate natural gas pipelines may construct without a case-specific authorization order and to increase the cost limits for such projects, among other changes.

On October 15, 2026, the FERC issued a Draft Policy Statement on Environmental Review of Natural Gas Act Applications stating that the FERC would no longer require applicants for Natural Gas Act authorizations to submit air dispersion modeling.

Air Quality Standards

In 2023, the EPA finalized its Good Neighbor Plan (the "Plan") which seeks to reduce nitrogen oxide pollution from power plants and other industrial facilities from 23 upwind states which the EPA determined is contributing to National Ambient Air

Quality Standards (NAAQS) nonattainment and interfering with maintenance of the 2015 ozone NAAQS in downwind states. As part of the Plan, the EPA announced that it would be issuing prescriptive emission standards for several sectors, including certain new and existing internal combustion engines of a certain size used in pipeline transportation of natural gas. The EPA's final rule was to become effective on August 4, 2023, and the prescribed emission standards were scheduled to be effective in 2026. However, on March 12, 2025, the EPA announced plans to end the Plan.

Operators and industry groups have challenged the Plan in the D.C. Circuit, as well as the legal predicates to the individual upwind states' inclusion in the Plan in the regional circuits. The effectiveness of the rule is currently stayed in the nine states within the Partnership's footprint, by nature of judicial stays of the legal predicate to the Plan, by judicial stay of the Plan itself by the United States Supreme Court, or by the administrative stay issued by the EPA in October 2024. On June 18, 2025, the United States Supreme Court ruled that the regional circuits are the appropriate venue for the proceedings. On July 30, 2025, the Court of Appeals for the Tenth Circuit placed the case in abeyance pending the EPA's reconsideration of its disapproval of upwind states' state implementation plans addressing their Plan obligations. Proceedings challenging the Plan in the D.C. Circuit were also placed in abeyance on May 2, 2025 pending the EPA's reconsideration of the Plan. The EPA is preparing a proposed rulemaking as part of the reconsideration process, and on January 27, 2026, the EPA announced its proposal to approve state implementation plans for eight states, including those in which we operate, which would resolve those states' obligations under the Good Neighbor Plan. We cannot predict with any certainty the substance of any later proposed rule or the potential impacts on the Partnership.

Additionally, on April 4, 2026, the EPA published a final rule finalizing revisions to certain aspects of Subparts OOOOb/OOOOc under the Clean Air Act that provide greater flexibility in venting and flaring from oil and gas operations. The EPA continues to develop proposals to revise other aspects of Subparts OOOOb/OOOOc.

The Partnership currently estimates that the existing final rule regarding the Plan would require retrofitting or replacement of approximately 192 engines in its interstate and intrastate natural gas transportation and storage operations. The Partnership is involved in challenging application of the Plan in the nine states impacted within its footprint. Compliance with the Plan (if implementation is not stayed or otherwise delayed) will still require substantial capital expenditures which could adversely affect our business in future periods. However, at this time, we are still assessing the potential costs of this rule and, given uncertainties resulting from the multiple legal challenges filed against the Plan in various states, in the D.C. Circuit and the United States Supreme Court, we cannot predict with any certainty what the final costs of compliance for the Plan for the Partnership ultimately may be.

OECD Pillar Two Global Minimum Tax

The acquisition of Parkland brings the Partnership into scope for Pillar Two global minimum tax. Several jurisdictions in which we now operate have enacted legislation implementing the Organization for Economic Co-operation and Development ("OECD") Pillar Two global minimum tax framework. These rules generally impose a 15% minimum top-up tax on the profits of large multinational enterprises. Sunoco LP estimates its Pillar Two global minimum tax expense to be immaterial in 2026 and has not accrued any current tax expense related to Pillar Two during the nine months ended September 30, 2026.

On January 5, 2026, the OECD released new guidance that provides relief for U.S. parented multinationals and establishes a side-by-side framework for the U.S. tax system to coexist with Pillar Two global minimum tax. Effective for fiscal years beginning on or after January 1, 2026, U.S. parented multinationals would be exempt from the main charging provisions of Pillar Two. Sunoco LP will continue to estimate and potentially accrue Pillar Two global minimum tax until the relevant jurisdictions in which Sunoco LP operates enact the side-by-side framework into law.

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, certain foreign currency transaction gains and losses, other non-operating income or expense items and certain non-recurring gains and losses. Inventory valuation adjustments that are excluded from the calculation of Adjusted EBITDA represent only the changes in lower of cost or market reserves on inventory that is carried at LIFO. These amounts are unrealized valuation adjustments applied to Sunoco LP's fuel volumes remaining in inventory at the end of the period.

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 following table, 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.

Consolidated Results

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$ 346	$ 230	$ 116	$ 1,160	$ 858	$ 302
Interstate transportation and storage	500	431	69	1,500	1,413	87
Midstream	864	751	113	2,635	2,444	191
NGL and refined products transportation and services	1,224	1,054	170	3,695	3,065	630
Crude oil transportation and services	871	746	125	2,574	2,220	354
Investment in Sunoco LP	1,049	489	560	2,889	1,401	1,488
Investment in USAC	198	160	38	580	459	121
All other	(21)	(23)	2	1	(58)	59
Adjusted EBITDA (consolidated)	$ 5,031	$ 3,838	$ 1,193	$ 15,034	$ 11,802	$ 3,232

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Reconciliation of net income to Adjusted EBITDA:						
Net income	$ 1,814	$ 1,292	$ 522	$ 6,320	$ 4,470	$ 1,850
Depreciation, depletion and amortization	1,599	1,440	159	4,757	4,191	566
Interest expense, net of interest capitalized	944	890	54	2,825	2,564	261
Income tax expense	187	87	100	516	207	309
Impairment losses	2	1	1	2	8	(6)
Non-cash compensation expense	49	40	9	137	110	27
Unrealized (gains) losses on commodity risk management activities	379	(1)	380	519	(32)	551
Inventory valuation adjustments (Sunoco LP)	(19)	(10)	(9)	(445)	(31)	(414)
Losses on extinguishments of debt	—	12	(12)	7	31	(24)
Adjusted EBITDA related to unconsolidated affiliates	196	193	3	588	542	46
Equity in earnings of unconsolidated affiliates	(112)	(116)	4	(330)	(313)	(17)
Other, net	(8)	10	(18)	138	55	83
Adjusted EBITDA (consolidated)	$ 5,031	$ 3,838	$ 1,193	$ 15,034	$ 11,802	$ 3,232

Net Income. For the three and nine months ended September 30, 2026 compared to the same periods last year, net income increased by $522 million and $1.85 billion, respectively. The increase for the three months ended September 30, 2026 was primarily due to higher segment margin from (i) our intrastate transportation and storage segment, where segment margin was favorably impacted by early volumes during the capacity ramp-up of the Hugh Brinson Pipeline, (ii) our midstream segment, where segment margin was favorably impacted by higher gathering and processing volumes as well as higher NGL prices and natural gas prices, and (iii) our investment in Sunoco LP and USAC segments, where segment margin increased due to recent acquisitions. These increases were partially offset by higher operating expenses, selling, general and administrative expenses, depreciation, depletion and amortization and interest expense. The increase for the nine months ended September 30, 2026 was primarily due to higher segment margin from (i) our intrastate transportation and storage segment, where segment margin was favorably impacted by wider basis differentials and early volumes from the commissioning and capacity ramp-up of the Hugh Brinson Pipeline, (ii) our midstream segment, where segment margin was favorably impacted by higher gathering and processing volumes, as well as higher NGL and natural gas prices, (iii) our NGL and refined products transportation and services segment and our crude oil transportation and services segment, where segment margin benefited from favorable market conditions and higher spreads, and (iv) our investment in Sunoco LP and USAC segments, where segment margin increased due to recent acquisitions. These increases were partially offset by higher operating expenses, selling, general and administrative expenses, depreciation, depletion and amortization and interest expense. These changes are discussed in more detail below and in "Segment Operating Results."

Adjusted EBITDA (consolidated). For the three and nine months ended September 30, 2026 compared to the same periods last year, Adjusted EBITDA increased by $1.19 billion and $3.23 billion, respectively, primarily due to increases in our intrastate transportation and storage segment, midstream segment, NGL and refined products transportation and services segment, crude oil transportation and services segment, and our investment in Sunoco LP segment.

Additional information on changes impacting net income and Adjusted EBITDA is available below and in "Segment Operating Results."

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased for the three and nine months ended September 30, 2026 compared to the same periods last year primarily due to additional depreciation and amortization from assets recently placed in service and recent acquisitions.

Interest Expense, Net of Interest Capitalized. Interest expense, net of interest capitalized, increased for the three and nine months ended September 30, 2026 compared to the same periods last year primarily due to an increase in aggregate debt balances following the acquisition of Parkland and the refinancing of certain preferred units with long-term debt.

Income Tax Expense. For the three and nine months ended September 30, 2026 compared to the same periods last year, income tax expense increased primarily due to increased corporate earnings from recent acquisitions. Some of the recent acquisitions have subsidiaries that operate in foreign jurisdictions where those subsidiaries are subject to statutory income tax rates that are higher than the U.S. federal corporate income tax rate. Additionally, the income tax expense from those recent acquisitions was further increased due to the non-deductibility of a portion of foreign currency exchange losses in certain Canadian subsidiaries and losses incurred in certain foreign subsidiaries that operate in foreign jurisdictions that do not impose a corporate income tax.

Impairment Losses. For the three and nine months ended September 30, 2025, the impairment losses were related to USAC's evaluation of the future deployment of its idle fleet under current market conditions.

Unrealized (Gains) Losses on Commodity Risk Management Activities. The unrealized gains and 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 gain and loss within each segment is included in "Segment Operating Results," and additional information on the commodity-related derivatives, including notional volumes, maturities and fair values, is available in "Item 3. Quantitative and Qualitative Disclosures About Market Risk" and in Note 12 to our consolidated financial statements included in "Item 1. Financial Statements."

Inventory Valuation Adjustments. Inventory valuation adjustments represent changes in lower of cost or market reserves using the LIFO method on Sunoco LP's inventory. These amounts are unrealized valuation adjustments applied to fuel volumes remaining in inventory at the end of the period. For the three months ended September 30, 2026 and 2025, the Partnership's cost of products sold included favorable inventory valuation adjustments of $19 million and $10 million, respectively, which increased net income. For the nine months ended September 30, 2026 and 2025, the Partnership's cost of products sold included favorable inventory valuation adjustments of $445 million and $31 million, respectively, which increased net income.

Losses on Extinguishments of Debt. For the nine months ended September 30, 2026, loss on extinguishment of debt was due to Energy Transfer and Sunoco LP's redemption of senior notes. For the three and nine months ended September 30, 2025, loss on extinguishment of debt was primarily related to Sunoco LP's termination of bridge financing related to the Parkland acquisition.

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

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

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Equity in earnings of unconsolidated affiliates:						
Citrus	$ 42	$ 41	$ 1	$ 118	$ 114	$ 4
MEP	20	19	1	62	54	8
White Cliffs	4	5	(1)	15	13	2
Explorer	2	8	(6)	13	22	(9)
SESH	15	14	1	45	42	3
Other	29	29	—	77	68	9
Total equity in earnings of unconsolidated affiliates	$ 112	$ 116	$ (4)	$ 330	$ 313	$ 17
Adjusted EBITDA related to unconsolidated affiliates [1]:						
Citrus	$ 91	$ 88	$ 3	$ 264	$ 255	$ 9
MEP	30	28	2	89	80	9
White Cliffs	9	10	(1)	30	28	2
Explorer	5	12	(7)	24	35	(11)
SESH	16	15	1	48	45	3
Other	45	40	5	133	99	34
Total Adjusted EBITDA related to unconsolidated affiliates	$ 196	$ 193	$ 3	$ 588	$ 542	$ 46
Distributions received from unconsolidated affiliates:						
Citrus	$ 26	$ 10	$ 16	$ 59	$ 76	$ (17)
MEP	23	26	(3)	82	81	1
White Cliffs	11	9	2	31	27	4
Explorer	4	8	(4)	16	23	(7)
SESH	20	15	5	50	38	12
Other	25	24	1	75	68	7
Total distributions received from unconsolidated affiliates	$ 109	$ 92	$ 17	$ 313	$ 313	$ —

[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 following tables 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 gain or loss 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 loss is added back and the unrealized gain is 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.

The following analysis of segment operating results includes a measure of segment margin. 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 following sections 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.

Intrastate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Natural gas transported (BBtu/d)	15,759	13,861	1,898	14,459	14,102	357
Withdrawals from storage natural gas inventory (BBtu)	—	—	—	23,698	8,225	15,473
Revenues	$ 1,081	$ 869	$ 212	$ 2,833	$ 3,094	$ (261)
Cost of products sold	661	546	115	1,503	2,071	(568)
Segment margin	420	323	97	1,330	1,023	307
Unrealized (gains) losses on commodity risk management activities	8	(16)	24	65	39	26
Operating expenses, excluding non-cash compensation expense	(75)	(72)	(3)	(215)	(190)	(25)
Selling, general and administrative expenses, excluding non-cash compensation expense	(13)	(12)	(1)	(41)	(36)	(5)
Adjusted EBITDA related to unconsolidated affiliates	7	6	1	20	17	3
Other	(1)	1	(2)	1	5	(4)
Segment Adjusted EBITDA	$ 346	$ 230	$ 116	$ 1,160	$ 858	$ 302

Volumes. For the three and nine months ended September 30, 2026 compared to the same periods last year, transported volumes of gas on our Texas intrastate pipelines increased primarily due to new third-party transportation contracts tied to the recently

in-service Hugh Brinson Pipeline and its downstream assets. Transported volumes reported above exclude volumes attributable to purchases and sales of gas for our pipelines' own accounts and the optimization of any unused capacity.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Transportation fees	$ 254	$ 218	$ 36	$ 706	$ 659	$ 47
Natural gas sales and other (excluding unrealized gains and losses)	149	67	82	547	300	247
Retained fuel (excluding unrealized gains and losses)	9	8	1	32	26	6
Storage margin (excluding unrealized gains and losses and fair value inventory adjustments)	16	14	2	110	77	33
Unrealized losses on commodity risk management activities and fair value inventory adjustments	(8)	16	(24)	(65)	(39)	(26)
Total segment margin	$ 420	$ 323	$ 97	$ 1,330	$ 1,023	$ 307

Segment Adjusted EBITDA. For the three months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $82 million in realized natural gas sales and other primarily due to early volumes during the capacity ramp-up of the Hugh Brinson Pipeline; and
- an increase of $36 million in transportation fees primarily due to new third-party transportation contracts tied to the recently in-service Hugh Brinson Pipeline and its downstream assets; partially offset by
- an increase of $3 million in operating expenses primarily due to employee related costs as well as volume and pricing increases across utilities and consumables.

For the nine months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $247 million in realized natural gas sales and other primarily due to wider basis differentials and a $75 million increase from early volumes during the commissioning and capacity ramp-up of the Hugh Brinson Pipeline;
- an increase of $47 million in transportation fees primarily due to new third-party transportation contracts tied to the recently in-service Hugh Brinson Pipeline and its downstream assets and higher reservation revenues on long-term third-party contracts;
- an increase of $33 million in storage margin due to favorable impacts from increased price volatility; and
- an increase of $6 million in retained fuel margin due to favorable gas pricing and volumes; partially offset by
- an increase of $5 million in selling, general and administrative expenses primarily due to legal fees; and
- an increase of $25 million in operating expenses primarily due to a $10 million increase from the Hugh Brinson Pipeline, a $6 million increase in employee related costs, a $4 million increase in maintenance and project related expenses, and a $3 million increase in utility costs.

Interstate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Natural gas transported (BBtu/d)	17,990	17,694	296	17,999	17,932	67
Natural gas sold (BBtu/d)	20	43	(23)	29	35	(6)
Revenues	$ 620	$ 603	$ 17	$ 1,863	$ 1,814	$ 49
Cost of products sold	3	3	—	10	8	2
Segment margin	617	600	17	1,853	1,806	47
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(216)	(271)	55	(661)	(681)	20
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(35)	(29)	(6)	(99)	(92)	(7)
Adjusted EBITDA related to unconsolidated affiliates	134	129	5	397	378	19
Other	—	2	(2)	10	2	8
Segment Adjusted EBITDA	$ 500	$ 431	$ 69	$ 1,500	$ 1,413	$ 87

Volumes. For the three months ended September 30, 2026 compared to the same period last year, transported volumes increased primarily due to more capacity sold and higher utilization on several of our systems due to higher demand. For the nine months ended September 30, 2026 compared to the same period last year, transport volumes increased due to increased demand across our systems.

Segment Adjusted EBITDA. For the three months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net impacts of the following:

- a decrease of $55 million in operating expenses primarily due to a $49 million decrease in ad valorem taxes including a $43 million reduction from the resolution of a prior period ad valorem tax obligation on our Rover system in 2025, a $9 million decrease in the revaluation of system gas and other system gas activity, and a $6 million decrease in project related expenses, partially offset by a $4 million increase in employee related costs and a $2 million increase related to volumes and pricing;
- an increase of $17 million in segment margin primarily due to a $23 million increase in transportation revenue from several of our interstate pipeline systems due to higher contracted volumes and higher utilization, partially offset by an aggregate $8 million decrease in operational gas sales; and
- an increase of $5 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to higher revenues from our Citrus, MEP and SESH joint ventures; partially offset by
- an increase of $6 million in selling, general and administrative expenses primarily due to higher professional fees, employee costs and allocated costs.

For the nine months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net impacts of the following:

- an increase of $47 million in segment margin primarily due to a $56 million increase in transportation revenue from several of our interstate pipeline systems due to higher contracted volumes and higher utilization, as well as a $6 million increase due to higher storage revenue, partially offset by a $15 million decrease in operational gas sales;
- a decrease of $20 million in operating expenses primarily due to a $50 million decrease in ad valorem taxes including a $43 million reduction from the resolution of a prior period ad valorem tax obligation on our Rover system in 2025, partially offset by a $14 million increase in employee related costs, a $6 million increase from one-time expenses, and a $10 million increase related to volumes, utility and fuel pricing, and other direct costs;
- an increase of $19 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to an $8 million increase from our MEP joint venture due to higher revenue, partially offset by higher operating expenses, an $8 million increase from our Citrus joint venture due to higher revenue and a $3 million increase from our SESH pipeline joint venture due to higher revenue; and

- an increase of $8 million in other primarily due to the realization of proceeds from a shipper bankruptcy settlement; partially offset by
- an increase of $7 million in selling, general and administrative expenses primarily due to a $4 million adjustment related to accrued excise taxes in the prior period and an aggregate $3 million increase in employee costs, allocated costs and insurance expense.

Midstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Gathered volumes (BBtu/d)	22,941	21,581	1,360	22,259	21,111	1,148
NGLs produced (MBbls/d)	1,269	1,149	120	1,224	1,140	84
Equity NGLs (MBbls/d)	74	67	7	74	64	10
Revenues	$ 3,909	$ 2,992	$ 917	$ 9,774	$ 9,783	$ (9)
Cost of products sold	2,512	1,746	766	5,578	5,917	(339)
Segment margin	1,397	1,246	151	4,196	3,866	330
Operating expenses, excluding non-cash compensation expense	(485)	(459)	(26)	(1,444)	(1,296)	(148)
Selling, general and administrative expenses, excluding non-cash compensation expense	(54)	(48)	(6)	(160)	(151)	(9)
Adjusted EBITDA related to unconsolidated affiliates	5	11	(6)	15	22	(7)
Other	1	1	—	28	3	25
Segment Adjusted EBITDA	$ 864	$ 751	$ 113	$ 2,635	$ 2,444	$ 191

Volumes. For the three and nine months ended September 30, 2026 compared to the same periods last year, gathering and processing volumes increased in most regions, primarily from new and upgraded plants in the Permian region and dry gas gathering in the Northeast and Ark-La-Tex regions. NGL production increased primarily due to increased Permian plant utilization from new and existing plants.

Segment Adjusted EBITDA. For the three months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impact of the following:

- an increase of $151 million in segment margin primarily due to an $82 million increase attributable to higher gathered and processed volumes from increased processing capacity and operational efficiencies, which includes an intercompany imbalance that is fully offset within our NGL and refined products transportation and services segment, as well as higher NGL prices of $61 million and higher natural gas prices of $9 million; partially offset by
- an increase of $6 million in selling, general, and administrative expenses due to higher corporate allocations;
- an increase of $26 million in operating expenses due to a $17 million increase in employee costs, a $13 million increase due to an increase in project activity, and a $3 million increase related to assets placed in service, partially offset by a $5 million decrease related to power optimization and a $5 million decrease in one-time items; and
- a decrease of $6 million in Adjusted EBITDA related to unconsolidated affiliates due to the one-time recognition of fee credits associated with a contract restructuring in the prior period.

For the nine months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impact of the following:

- an increase of $330 million in segment margin primarily due to a $250 million increase attributable to higher gathered and processed volumes from increased processing capacity and operational efficiencies, higher NGL prices of $127 million, higher natural gas prices of $17 million, and a $14 million increase due to reduced third-party NGL transportation and fractionation costs from our Oklahoma processing facilities, partially offset by a $160 million decrease attributable to the non-recurring recognition of certain amounts associated with Winter Storm Uri in the prior period; and
- an increase of $25 million in other income due to $15 million in proceeds from a shipper bankruptcy settlement and $11 million from the recognition of proceeds from a business interruption claim; partially offset by

- an increase of $148 million in operating expenses due to a $52 million increase in employee costs, a $43 million increase in environmental reserves, a $39 million increase related to the 2025 adjustment of certain estimates, a $12 million increase related to an asset abandonment, and an $8 million increase related to assets placed in service, partially offset by a $5 million decrease in ad valorem taxes;
- an increase of $9 million in selling, general, and administrative expenses primarily due to higher corporate allocations; and
- a decrease of $7 million in Adjusted EBITDA related to unconsolidated affiliates due to the one-time recognition of fee credits associated with a contract restructuring in the prior period.

NGL and Refined Products Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
NGL transportation volumes (MBbls/d)	2,630	2,487	143	2,566	2,333	233
Refined products transportation volumes (MBbls/d)	539	601	(62)	567	591	(24)
NGL and refined products terminal volumes (MBbls/d)	1,805	1,660	145	1,798	1,556	242
NGL fractionation volumes (MBbls/d)	1,184	1,123	61	1,192	1,121	71
Revenues	$ 7,633	$ 5,853	$ 1,780	$ 22,025	$ 18,703	$ 3,322
Cost of products sold	6,351	4,493	1,858	17,762	14,769	2,993
Segment margin	1,282	1,360	(78)	4,263	3,934	329
Unrealized (gains) losses on commodity risk management activities	276	(4)	280	379	(64)	443
Operating expenses, excluding non-cash compensation expense	(313)	(294)	(19)	(895)	(771)	(124)
Selling, general and administrative expenses, excluding non-cash compensation expense	(47)	(41)	(6)	(143)	(130)	(13)
Adjusted EBITDA related to unconsolidated affiliates	26	33	(7)	88	96	(8)
Other	—	—	—	3	—	3
Segment Adjusted EBITDA	$ 1,224	$ 1,054	$ 170	$ 3,695	$ 3,065	$ 630

Volumes. For the three and nine months ended September 30, 2026 compared to the same periods last year, NGL transportation, fractionation, and terminal throughput volumes increased due to higher volumes from the Permian region, as well as increased NGL exports.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Transportation margin	$ 726	$ 743	$ (17)	$ 2,071	$ 2,062	$ 9
Fractionators and refinery services margin	257	230	27	791	692	99
Terminal services margin	287	271	16	869	755	114
Storage margin	80	81	(1)	256	237	19
Marketing margin	208	31	177	655	124	531
Unrealized gains (losses) on commodity risk management activities	(276)	4	(280)	(379)	64	(443)
Total segment margin	$ 1,282	$ 1,360	$ (78)	$ 4,263	$ 3,934	$ 329

Segment Adjusted EBITDA. For the three months ended September 30, 2026 compared to the same period last 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 $177 million in marketing margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $143 million increase resulting from more favorable market conditions (which we anticipate will be partially offset with $100 million in realized derivative losses in future periods) and a $35 million increase in refined product margins as a result of higher spreads;
- an increase of $27 million in fractionators and refinery services margin primarily due to higher throughput; and
- an increase of $16 million in terminal services margin primarily due to a $12 million increase in fees from increased export volumes and rates at our Nederland and Marcus Hook terminals, and a $4 million increase from higher throughput and storage at our refined product terminals; partially offset by
- a decrease of $17 million in transportation margin due to a $22 million decrease on our Gulf Coast pipeline due primarily to an intercompany imbalance that is fully offset within our midstream segment, and a $2 million decrease due to lower refined product transportation volumes due to third-party refinery issues. These decreases were partially offset by a $7 million increase related to higher rates on our Northeast NGL pipelines;
- an increase of $19 million in operating expenses primarily due to a $15 million increase in utilities costs driven by higher utility pricing, a $9 million increase in employee costs, and an $8 million increase in office expenses. These increases were partially offset by a $15 million decrease related to investigation and remediation costs;
- a decrease of $7 million in Adjusted EBITDA related to unconsolidated affiliates due to downtime resulting from weather related issues at a joint venture facility; and
- an increase of $6 million in selling, general and administrative expenses primarily due to higher corporate allocations.

For the nine months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impact of the following:

- an increase of $531 million in marketing margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $354 million increase resulting from more favorable market conditions (which we anticipate will be partially offset with $100 million in realized derivative losses in future periods), a $112 million increase in refined product margins as result of higher spreads, and $65 million in hedge-related gains during the first quarter of 2026 which offset physical losses realized during the fourth quarter of 2025;
- an increase of $114 million in terminal services margin primarily due to a $92 million increase in fees from loading increased volumes at higher rates for export at our Nederland and Marcus Hook terminals and a $22 million increase from higher throughput and storage at our refined product terminals;
- an increase of $99 million in fractionators and refinery services margin primarily due to higher throughput;
- an increase of $9 million in transportation margin due to a $59 million increase primarily related to higher throughput transporting volumes from our Mont Belvieu fractionation facility to our Nederland terminal for export. This increase was partially offset by a $39 million intercompany imbalance that is completely offset within our midstream segment, a $6 million decrease from lower NGL throughput on our Mariner West system due to a third-party operational issue, and a $5 million decrease due to lower refined product transport volumes due to third-party refinery issues; and
- an increase of $19 million in storage margin primarily due to an increase in fees generated from export volumes, as well as increases related to blending activity due to a more favorable pricing environment; partially offset by
- an increase of $124 million in operating expenses primarily due to a $57 million increase in utilities costs driven by higher utility pricing across our system, a $28 million increase from certain one-time credits recognized in the prior period, a $22 million increase in employee costs, a $7 million increase in office expenses, and increases totaling $10 million from various other operating expenses;
- an increase of $13 million in selling, general and administrative expenses primarily due to higher legal fees and corporate allocations; and
- a decrease of $8 million in Adjusted EBITDA related to unconsolidated affiliates due to downtime resulting from weather related issues at a joint venture facility.

Crude Oil Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Crude oil transportation volumes (MBbls/d)	7,107	7,023	84	7,243	6,932	311
Crude oil terminal volumes (MBbls/d)	4,167	4,262	(95)	4,533	4,500	33
Revenues	$ 9,414	$ 6,043	$ 3,371	$ 28,223	$ 17,999	$ 10,224
Cost of products sold	8,425	5,047	3,378	24,983	14,986	9,997
Segment margin	989	996	(7)	3,240	3,013	227
Unrealized (gains) losses on commodity risk management activities	152	18	134	89	(7)	96
Operating expenses, excluding non-cash compensation expense	(245)	(243)	(2)	(699)	(693)	(6)
Selling, general and administrative expenses, excluding non-cash compensation expense	(38)	(36)	(2)	(84)	(118)	34
Adjusted EBITDA related to unconsolidated affiliates	12	11	1	27	25	2
Other	1	—	1	1	—	1
Segment Adjusted EBITDA	$ 871	$ 746	$ 125	$ 2,574	$ 2,220	$ 354

Volumes. For the three and nine months ended September 30, 2026 compared to the same periods last year, crude oil transportation volumes were higher due to higher volumes on our Texas pipeline system, Bakken gathering systems, and Mid-continent pipelines, partially offset by lower Bakken Pipeline and Bayou Bridge volumes. Crude terminal volumes were lower for the three-month period due to lower customer throughput at our Gulf Coast Terminals, but higher for the nine-month period due to higher customer throughput related to strategic petroleum reserve releases and crude export demand at our Gulf Coast terminals.

Segment Adjusted EBITDA. For the three months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the net impact of the following:

- an increase of $127 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $193 million increase from crude marketing activities due to more favorable market conditions (which we anticipate will be partially offset with $100 million in realized derivative losses in future periods) and a $7 million increase from crude terminal revenue. Segment margin was also impacted by a $50 million decrease in transportation revenue and a $22 million decrease in gathering revenue; partially offset by
- an increase of $2 million in operating expenses primarily due to a $5 million increase in utilities costs driven by higher utility pricing and a $5 million increase in employee costs, partially offset by a reduction in ad valorem taxes; and
- an increase of $2 million in selling, general and administrative expenses primarily due to higher corporate allocations.

For the nine months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the net impact of the following:

- an increase of $323 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) due to a $365 million increase from crude marketing activities due to more favorable market conditions (which we anticipate will be partially offset with $100 million in realized derivative losses in future periods), a $30 million increase in gathering revenue, and a $7 million increase in crude terminal revenue; partially offset by a $78 million decrease in transportation revenue;
- a decrease of $34 million in selling, general and administrative expenses primarily due to an adjustment to the accrual for a litigation contingency; and
- an increase of $2 million in Adjusted EBITDA related to unconsolidated affiliates due to higher volumes and crude prices; partly offset by
- an increase of $6 million in operating expenses primarily due to a $17 million increase in employee-related expenses and a $14 million increase in utilities costs driven by higher utility pricing, partially offset by a $9 million decrease in ad valorem taxes and a $15 million decrease from maintenance project-related expenses and third-party trucking.

Investment in Sunoco LP

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Revenues	$ 18,029	$ 6,032	$ 11,997	$ 42,978	$ 16,601	$ 26,377
Cost of products sold	16,469	5,386	11,083	38,265	14,733	23,532
Segment margin	1,560	646	914	4,713	1,868	2,845
Unrealized (gains) losses on commodity risk management activities	(57)	15	(72)	(7)	7	(14)
Operating expenses, excluding non-cash compensation expense	(380)	(180)	(200)	(1,195)	(500)	(695)
Selling, general and administrative expenses, excluding non-cash compensation expense	(143)	(47)	(96)	(449)	(130)	(319)
Adjusted EBITDA related to unconsolidated affiliates	56	58	(2)	200	159	41
Inventory valuation adjustments	(19)	(10)	(9)	(445)	(31)	(414)
Other	32	7	25	72	28	44
Segment Adjusted EBITDA	$ 1,049	$ 489	$ 560	$ 2,889	$ 1,401	$ 1,488

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

Segment Adjusted EBITDA. For the three months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our investment in Sunoco LP segment increased due to the net impact of the following:

- an increase of $833 million in segment margin (excluding unrealized gains and losses on commodity risk management activities and inventory valuation adjustments) primarily due to recent acquisitions; partially offset by
- an increase of $200 million in operating expenses primarily due to increased costs resulting from recently acquired businesses; and
- an increase of $96 million in selling, general and administrative expenses primarily due to increased costs resulting from recently acquired businesses.

For the nine months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our investment in Sunoco LP segment increased due to the net impact of the following:

- an increase of $2.42 billion in segment margin (excluding unrealized gains and losses on commodity risk management activities and inventory valuation adjustments) primarily due to recent acquisitions, as well as a $102 million favorable impact from a one-time gain on sale of inventory in the first quarter of the current year; and
- an increase of $41 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to the Parkland acquisition and ET-S Permian joint venture; partially offset by
- an increase of $695 million in operating expenses primarily due to increased costs resulting from recently acquired businesses; and
- an increase of $319 million in selling, general and administrative expenses primarily due to increased costs resulting from recently acquired businesses.

Investment in USAC

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Revenues	$ 358	$ 251	$ 107	$ 1,031	$ 746	$ 285
Cost of products sold	34	34	—	96	112	(16)
Segment margin	324	217	107	935	634	301
Operating expenses, excluding non-cash compensation expense	(99)	(43)	(56)	(279)	(133)	(146)
Selling, general and administrative expenses, excluding non-cash compensation expense	(30)	(14)	(16)	(90)	(42)	(48)
Other	3	—	3	14	—	14
Segment Adjusted EBITDA	$ 198	$ 160	$ 38	$ 580	$ 459	$ 121

The investment in USAC segment reflects the consolidated results of USAC.

Segment Adjusted EBITDA. For the three months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our investment in USAC segment increased due to the net impact of the following:

- an increase of $107 million in segment margin primarily due to the J-W Power Acquisition and increases in USAC's legacy business; partially offset by
- an increase of $72 million in operating expense and selling, general and administrative expense primarily related to the J-W Power Acquisition, as well as increased expenses in outside services and professional fees and increased unit-based compensation expenses.

For the nine months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our investment in USAC segment increased due to the net impact of the following:

- an increase of $301 million in segment margin primarily due to the J-W Power Acquisition and increases in USAC's legacy business; partially offset by
- an increase of $194 million in operating expense and selling, general and administrative expense primarily related to the J-W Power Acquisition, as well as increased expenses in outside services and professional fees and increased unit-based compensation expenses.

All Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	Change	2026	2025	Change
Revenues	$ 911	$ 923	$ (12)	$ 2,530	$ 2,854	$ (324)
Cost of products sold	923	895	28	2,419	2,799	(380)
Segment margin	(12)	28	(40)	111	55	56
Unrealized gains on commodity risk management activities	—	(13)	13	(7)	(7)	—
Operating expenses, excluding non-cash compensation expense	(5)	(17)	12	(18)	(18)	—
Selling, general and administrative expenses, excluding non-cash compensation expense	(14)	(11)	(3)	(31)	(37)	6
Adjusted EBITDA related to unconsolidated affiliates	2	2	—	5	4	1
Other and eliminations	8	(12)	20	(59)	(55)	(4)
Segment Adjusted EBITDA	$ (21)	$ (23)	$ 2	$ 1	$ (58)	$ 59

Amounts reflected in our all other segment primarily include:

- our natural gas marketing operations;

- our wholly owned natural gas compression operations; and
- our natural resources business.

Segment Adjusted EBITDA. For the three months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment increased due to the net impact of the following:

- an increase of $13 million due to a decrease in the intersegment elimination of Sunoco LP's 32.5% share of ET-S Permian, which is consolidated in our crude oil transportation and services segment and also reflected as an unconsolidated affiliate in our investment in Sunoco LP segment; partially offset by
- a decrease of $6 million in our dual drive compression business; and
- a decrease of $6 million in our natural gas marketing business due to lower spreads and lower hedge gains.

For the nine months ended September 30, 2026 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment increased due to the net impact of the following:

- an increase of $78 million in our natural gas marketing driven by higher spreads and gains on residue gas sales; partially offset by
- a decrease of $15 million in our dual drive compression business.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our ability to satisfy obligations and pay distributions to unitholders will depend on our future performance, which will be subject to prevailing economic, financial, business and weather conditions, and other factors, many of which are beyond management's control. We believe that we have sufficient liquidity and sources of funding to meet our cash requirements over the near term and for the longer term.

We currently expect capital expenditures in 2026 to be approximately as follows (including capitalized interest and overhead and only our proportionate share for joint ventures, but excluding capital expenditures related to our investments in Sunoco LP and USAC):

	Growth	Maintenance
Intrastate transportation and storage	$ 1,455	$ 80
Interstate transportation and storage	785	265
Midstream	1,420	385
NGL and refined products transportation and services	1,225	165
Crude oil transportation and services	375	170
All other (including eliminations)	240	85
Total capital expenditures	$ 5,500	$ 1,150

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, including as a result of the recent governmental action on tariffs, and other factors beyond our control. However, we have included these factors in our anticipated growth capital expenditures for each year.

We generally fund capital expenditures and distributions with cash flows from operating activities.

Sunoco LP currently expects to spend between $400 million and $450 million in maintenance capital expenditures and at least $600 million in growth capital for the full year 2026.

USAC currently plans to invest between $60 million and $70 million in maintenance capital expenditures and between $230 million and $250 million in expansion capital expenditures for the full year 2026.

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 for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions and other factors.

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations"), 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 acquisition 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 price risk management assets and liabilities, the timing of accounts receivable collection, the timing of payments on accounts payable, the timing of purchase and sales of inventories and the timing of advances and deposits received from customers.

Nine months ended September 30, 2026 compared to nine months ended September 30, 2025. Cash provided by operating activities during 2026 was $11.67 billion compared to $8.25 billion for 2025, and net income was $6.32 billion for 2026 and $4.47 billion for 2025. The difference between net income and net cash provided by operating activities for the nine months ended September 30, 2026 primarily consisted of net changes in operating assets and liabilities (net of effects of acquisitions) of $784 million, cash distributions of $199 million received from unconsolidated affiliates that are deemed to be paid from cumulative earnings, cash distributions of $39 million paid on unvested awards, and other items totaling $4.41 billion, which includes non-cash items and items related to investing and financing activities that are included in net income.

The non-cash activity in 2026 and 2025 consisted primarily of depreciation, depletion and amortization of $4.76 billion and $4.19 billion, respectively, deferred income tax expense of $188 million and $68 million, respectively, favorable inventory valuation adjustments of $445 million and $31 million, respectively, non-cash compensation expense of $137 million and $110 million, respectively, and in 2026, loss on foreign currency exchange of $94 million related to Sunoco LP's foreign operations. For 2026 and 2025, net income also included equity in earnings of unconsolidated affiliates of $330 million and $313 million, respectively, losses on extinguishments of debt of $7 million and $31 million, respectively, and impairment losses of $2 million and $8 million, respectively.

Cash paid for interest, net of interest capitalized, was $2.45 billion and $2.05 billion for the nine months ended September 30, 2026 and 2025, respectively. Interest capitalized was $174 million and $98 million for the nine months ended September 30, 2026 and 2025, respectively.

Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid for acquisitions, capital expenditures, cash contributions to our joint ventures and cash proceeds from sales or contributions of assets or businesses. In addition, distributions from equity investees are included in cash flows from investing activities if the distributions are deemed to be a return of the Partnership's investment. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Nine months ended September 30, 2026 compared to nine months ended September 30, 2025. Cash used in investing activities during 2026 was $6.01 billion compared to $4.43 billion for 2025. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2026 were $5.26 billion compared to $4.15 billion for 2025. Additional detail related to our capital expenditures is provided in the table below.

In 2026, USAC paid $445 million, net of cash acquired, for the acquisition of J-W Power Company. In 2026, Sunoco LP paid $194 million, net of cash acquired, for the TanQuid acquisition; $75 million, net of cash acquired, for the Delta acquisition; and $87 million in cash for other acquisitions.

In 2025, we paid $176 million in cash for the acquisition of two terminal facilities and Sunoco LP paid $189 million in cash for acquisitions of fuel equipment, motor fuel inventory, supply agreements, and fuel distribution consignment sites.

In 2026 and 2025, we received cash distributions from unconsolidated affiliates in excess of cumulative earnings of $114 million and $77 million, respectively, and we paid cash contributions to unconsolidated affiliates of $40 million and $5 million, respectively.

The following is a summary of capital expenditures (including only our proportionate share for joint ventures, net of contributions in aid of construction costs) on an accrual basis for the nine months ended September 30, 2026:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Intrastate transportation and storage	$ 1,184	$ 50	$ 1,234
Interstate transportation and storage	496	178	674
Midstream	954	252	1,206
NGL and refined products transportation and services	903	106	1,009
Crude oil transportation and services	235	112	347
Investment in Sunoco LP	352	286	638
Investment in USAC	161	45	206
All other (including eliminations)	147	68	215
Total capital expenditures	$ 4,432	$ 1,097	$ 5,529

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 increase between the periods based on increases in the number of common units outstanding or increases in the distribution rate.

Nine months ended September 30, 2026 compared to nine months ended September 30, 2025. Cash used in financing activities during 2026 was $6.01 billion compared to $562 million for 2025. During 2026, we had a net increase in our debt level of $231 million compared to a net increase of $3.41 billion for 2025. In 2026 and 2025, we paid debt issuance costs of $80 million and $111 million, respectively. In 2026, we paid $900 million in cash for the redemption of our Series H Preferred Units and in 2025, we paid $500 million in cash for the redemption of our Series F Preferred Units. In 2025, Sunoco LP received $1.47 billion in cash from the issuance of the Sunoco LP Series A Preferred Units.

In 2026 and 2025, we paid distributions of $3.61 billion and $3.50 billion, respectively, to our partners, we paid distributions of $1.66 billion and $1.31 billion, respectively, to noncontrolling interests, and we paid distributions of $30 million and $45 million, respectively, to redeemable noncontrolling interests.

In 2026 and 2025, we received capital contributions of $11 million and $27 million, respectively, in cash from noncontrolling interests. In 2026, we received capital contributions of $16 million in cash from redeemable noncontrolling interests.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	September 30, 2026	December 31, 2025
Energy Transfer indebtedness:		
Notes and debentures[1] [2]	$ 51,470	$ 48,870
Five-Year Credit Facility[2]	565	2,856
Subsidiary indebtedness:		
Transwestern senior notes	75	75
Bakken Project senior notes	850	850
Sunoco LP senior notes, bonds and lease-related obligations[1][2]	13,131	13,470
USAC senior notes	2,350	1,750
Sunoco LP credit facility	111	—
USAC credit facility	684	795
Other long-term debt	15	19
Net unamortized premiums, discounts and fair value adjustments	12	32
Deferred debt issuance costs	(413)	(384)
Total debt	68,850	68,333
Less: current maturities of long-term debt	12	25
Long-term debt, less current maturities	$ 68,838	$ 68,308

[1] As of September 30, 2026, these balances included approximately $4.35 billion aggregate principal amount due on or before September 30, 2027, which were classified as long-term as management has the intent and ability to refinance the borrowings on a long-term basis.

[2] See additional information below under “Recent Transactions.”

Recent Transactions

Energy Transfer Notes Issuances and Redemptions

In January 2026, the Partnership issued $1.00 billion aggregate principal amount of 4.55% senior notes due 2031, $1.00 billion aggregate principal amount of 5.35% senior notes due 2036 and $1.00 billion aggregate principal amount of 6.30% senior notes due 2056. The Partnership used the net proceeds to refinance existing indebtedness, including to repay commercial paper and borrowings under its Five-Year Credit Facility.

In January 2026, the Partnership redeemed its $1.00 billion aggregate principal amount of 4.75% senior notes due January 2026 using cash on hand and commercial paper borrowings.

In February 2026, the Partnership redeemed its $600 million aggregate principal amount of 5.625% senior notes due May 2027 using cash on hand and commercial paper borrowings.

In July 2026, the Partnership issued $650 million aggregate principal amount of its Series 2026A Junior Subordinated Notes due 2057 (the “Series 2026A notes”) and $1.10 billion aggregate principal amount of its Series 2026B Junior Subordinated Notes due 2057 (the “Series 2026B notes”). Initially, the Series 2026A notes will bear interest at an annual rate of 6.550% and the Series 2026B notes will bear interest at an annual rate of 6.700%. The Partnership used the net proceeds to redeem the Series H Preferred Units, to repay borrowings under its Five-Year Credit Facility and for general partnership purposes.

In July 2026, the Partnership redeemed its $550 million aggregate principal amount of 3.90% senior notes due July 2026 using cash on hand and commercial paper borrowings.

Sunoco LP Senior Notes Issuances and Redemption

In March 2026, Sunoco LP issued $600 million aggregate principal amount of 5.375% senior notes due 2031 and $600 million aggregate principal amount of 5.625% senior notes due 2034. These notes will mature on July 15, 2031 and July 15, 2034, respectively, and interest is payable semi-annually on January 15 and July 15 of each year, commencing on July 15, 2026. Sunoco LP used a portion of the net proceeds from this private offering to redeem in full its $500 million aggregate principal amount of 6.000% senior notes due 2026 and its $600 million aggregate principal amount of 6.000% senior notes due 2027.

In March 2026, Sunoco LP redeemed Parkland’s remaining senior notes.

In June 2026, Sunoco LP redeemed all of its outstanding 3.875% CAD senior notes due 2026.

In August 2026, Sunoco LP redeemed all of its outstanding 6.000% CAD senior notes due 2028.

USAC Senior Note Issuance

In September 2026, USAC issued $600 million aggregate principal amount of 6.750% senior notes due 2035. These notes will mature on April 1, 2035, and interest is payable semi-annually on April 1 and October 1 of each year, commencing on April 1, 2027.

Credit Facilities and Commercial Paper

Five-Year Credit Facility

As of September 30, 2026, the Five-Year Credit Facility had $565 million of outstanding borrowings, $441 million of which consisted of commercial paper. The amount available for future borrowings was $4.41 billion, after accounting for outstanding letters of credit in the amount of $29 million. The weighted average interest rate on the total amount outstanding as of September 30, 2026 was 4.36%.

Sunoco LP Credit Facility

As of September 30, 2026, Sunoco LP's credit facility, which matures in June 2030, had $111 million of outstanding borrowings, substantially all of which were CAD-denominated, and $84 million in standby letters of credit. The unused availability on Sunoco LP's revolving credit facility as of September 30, 2026 was $2.30 billion. The weighted average interest rate on the total amount outstanding as of September 30, 2026 was 4.35%.

Sunoco LP Receivables Financing Agreement

Upon the closing of Sunoco LP's acquisition of NuStar, the commitments under NuStar's receivables financing agreement were reduced to zero during a suspension period, for which the period end has not been determined. As of September 30, 2026, this facility had no outstanding borrowings. On October 8, 2026, pursuant to a payoff letter with PNC Bank, National Association, as administrative agent, the receivables financing agreement and the related transaction documents were terminated and all related security interests and liens were released.

USAC Credit Facility

As of September 30, 2026, USAC's credit facility, which matures in August 2030, had $684 million of outstanding borrowings and $2 million outstanding letters of credit. As of September 30, 2026, USAC's credit facility had $1.06 billion of remaining unused availability. The weighted average interest rate on the total amount outstanding as of September 30, 2026 was 5.64%.

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 September 30, 2026.

CASH DISTRIBUTIONS

Cash Distributions Paid by Energy Transfer

Under its Partnership Agreement, Energy Transfer will distribute all of its Available Cash, as defined in the Partnership Agreement, within 50 days following the end of each fiscal quarter. Available Cash generally means, with respect to any quarter, all cash on hand at the end of such quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of our General Partner to provide for future cash requirements.

Cash Distributions on Energy Transfer Common Units

Distributions declared and/or paid with respect to Energy Transfer common units subsequent to December 31, 2025 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2025	February 6, 2026	February 19, 2026	$ 0.3350
March 31, 2026	May 8, 2026	May 20, 2026	0.3375
June 30, 2026	August 7, 2026	August 19, 2026	0.3400
September 30, 2026	November 6, 2026	November 19, 2026	0.3425

Cash Distributions on Energy Transfer Preferred Units

Distributions declared on the Energy Transfer Preferred Units were as follows:

Period Ended	Record Date	Payment Date	Series B [2]	Series G [2]	Series H [2]	Series I [1]
December 31, 2025	February 1, 2026	February 15, 2026	$ 33.125	$ —	$ —	$ 0.2111
March 31, 2026	May 1, 2026	May 15, 2026	—	35.630	32.500	0.2111
June 30, 2026	August 3, 2026	August 17, 2026	33.125	—	16.611	0.2111
September 30, 2026	November 4, 2026	November 13, 2026	—	35.630	—	0.2111

(1) The record date and payment date shown above apply to all Energy Transfer Preferred Units, except for the Series I Preferred Units. For the period ended December 31, 2025, the cash distribution on Series I Preferred Units was paid on February 17, 2026 to unitholders of record as of the close of business on February 4, 2026. For the period ended March 31, 2026, the cash distribution on Series I Preferred Units was paid on May 15, 2026 to unitholders of record as of the close of business on May 4, 2026. For the period ended June 30, 2026, the cash distribution on Series I Preferred Units was paid on August 14, 2026 to unitholders of record as of the close of business on August 4, 2026. For the period ended September 30, 2026, the cash distribution on Series I Preferred Units will be paid on November 13, 2026 to unitholders of record as of the close of business on November 4, 2026.

(2) Series B and Series G distributions are currently paid on a semi-annual basis. Distributions on the Series B Preferred Units will begin to be paid quarterly on February 15, 2028. The final distributions on Series H Preferred Units were paid in conjunction with the Series H Preferred Unit redemption on August 17, 2026.

Description of Energy Transfer Preferred Units

A summary of the distribution and redemption rights associated with the Energy Transfer Preferred Units is included in Note 9 in "Item 1. Financial Statements."

Cash Distributions Paid by Subsidiaries

The Partnership's consolidated financial statements include SunocoCorp, Sunoco LP and USAC, as well as other non-wholly owned consolidated joint ventures. The following sections describe cash distributions made by our publicly traded subsidiaries, SunocoCorp, Sunoco LP and USAC, all of which are required to distribute all cash on hand (less appropriate reserves determined by the boards of directors of their respective general partners) subsequent to the end of each quarter.

Cash Distributions Paid by SunocoCorp

Distributions on SunocoCorp's common units declared and/or paid by SunocoCorp subsequent to December 31, 2025 were as follows:

Quarter Ended	Payment Date	Rate
December 31, 2025	February 19, 2026	$ 0.9317
March 31, 2026	May 20, 2026	0.9899
June 30, 2026	August 19, 2026	1.0023
September 30, 2026	November 19, 2026	1.0148

Cash Distributions Paid by Sunoco LP

Distributions on Sunoco LP's common units and Class D Units declared and/or paid by Sunoco LP subsequent to December 31, 2025 were as follows:

Quarter Ended	Payment Date	Rate
December 31, 2025	February 19, 2026	$ 0.9317
March 31, 2026	May 20, 2026	0.9899
June 30, 2026	August 19, 2026	1.0023
September 30, 2026	November 19, 2026	1.0148

Distributions on Sunoco LP's Series A Preferred Units, which are paid semi-annually, were as follows:

Record Date	Payment Date	Rate
March 2, 2026	March 18, 2026	$ 39.375
September 1, 2026	September 18, 2026	39.375

Cash Distributions Paid by USAC

Distributions on USAC's common units declared and/or paid by USAC subsequent to December 31, 2025 were as follows:

Quarter Ended	Payment Date	Rate
December 31, 2025	February 6, 2026	$ 0.525
March 31, 2026	May 8, 2026	0.525
June 30, 2026	August 7, 2026	0.525
September 30, 2026	November 6, 2026	0.525

CRITICAL ACCOUNTING ESTIMATES

The Partnership's critical accounting estimates are described in its Annual Report on Form 10-K filed with the SEC on February 19, 2026. We have not made any changes to the accounting policies involving critical accounting estimates subsequent to the Form 10-K filing. Changes to any of the related estimate amounts are discussed in the notes to consolidated financial statements included in "Item 1. Financial Statements" in this quarterly report on Form 10-Q.

FORWARD-LOOKING STATEMENTS

This quarterly 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 quarterly 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 ability of our subsidiaries to make cash distributions to us, which is dependent on their results of operations, cash flows and financial condition;
- the actual amount of cash distributions by our subsidiaries to us;
- the volumes transported on our subsidiaries' pipelines and gathering systems;
- the level of throughput in our subsidiaries' processing and treating facilities;
- the fees our subsidiaries charge and the margins they realize for their gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- impacts of world health events;
- the possibility of cyber and malware attacks;
- 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, taxation and tariffs;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our subsidiaries' 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 subsidiaries' pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our subsidiaries' liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our subsidiaries' customers;
- risks related to the development of new infrastructure projects or other growth projects, including failure to make sufficient progress to justify continued development, delays in obtaining customers, increased costs of financing and raw materials and regulatory, environmental, political and legal uncertainties that may affect the timing and cost of these projects;
- risks associated with the construction of new pipelines, treating and processing facilities or other facilities, or additions to our subsidiaries' existing pipelines and their 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 subsidiaries' 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 our subsidiaries own noncontrolling interests, including risks related to management actions at such entities that our subsidiaries 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;
- the costs and effects of legal and administrative proceedings; and
- risks associated with a potential failure to successfully combine our business with those of companies we have acquired or may acquire in the future.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risks described under "Part I - Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2025 filed with the SEC on February 19, 2026, in "Part II - Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2026 filed with the SEC on May 7, 2026 and in the Current Report on Form 8-K12B filed with the SEC on July 6, 2026. Any forward-looking statement made by us in this Quarterly Report on Form 10-Q 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.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in "Part II - Item 7A - Quantitative and Qualitative Disclosures About Market Risk" included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2025 filed with the SEC on February 19, 2026, in addition to the accompanying notes and management's discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2025. Since December 31, 2025, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

The following table summarizes our commodity-related financial derivative instruments and fair values, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Dollar amounts are presented in millions.

	September 30, 2026			December 31, 2025		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
Natural Gas (BBtu)	(100,553)	$ 5	$ 14	(233,645)	$ 32	$ 9
Power (Megawatt)	(1,435,071)	10	9	(461,896)	2	4
Crude, NGL and refined products (MBbls)	(25,719)	(330)	175	(59,247)	106	131
Other	various	(63)	5	various	3	7
Fair Value Hedging Derivatives						
Natural Gas (BBtu)	(87,170)	7	15	(100,346)	22	20

The fair values of the commodity-related financial positions have been determined using independent third-party prices, readily available market information and appropriate valuation techniques. Non-trading positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above tables. Price-risk sensitivities were calculated by assuming a theoretical 10% change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in net income or in other comprehensive income. In the event of an actual 10% change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10% due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

Interest Rate Risk

As of September 30, 2026, we and our subsidiaries had $1.96 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $20 million annually. However, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock in the rate on a portion of anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes (dollar amounts presented in millions):

		Notional Amount Outstanding
Term	Type[1]	September 30, 2026
Sunoco LP:		
December 2030 [2]	Pay an average fixed rate of 2.5095% and receive a floating rate	$ 216

[1] Floating rates are based on EURIBOR.

[2] The December 2030 interest rate swap was acquired in conjunction with Sunoco LP's TanQuid acquisition in 2026, with a notional amount of €191 million ($216 million).

Foreign Currency Translation Risk

We generate revenues, incur expenses, and maintain investments and subsidiaries in currencies other than the U.S. dollar. As a result, our reported earnings, cash flows, and AOCI are exposed to fluctuations in foreign currency exchange rates. Changes in exchange rates can affect the U.S. dollar value of our foreign-currency-denominated assets and liabilities, as well as the translation of the operating results and financial position of our international subsidiaries. We may utilize derivative instruments, including foreign currency forward contracts and other hedging strategies, to mitigate the effects of foreign currency-denominated cash flow and earnings exposures. As of September 30, 2026, the Partnership did not have any material outstanding foreign currency derivatives.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Under the supervision and with the participation of senior management, including the Co-Chief Executive Officers (Co-Principal Executive Officers) and the Chief Financial Officer (Principal Financial Officer) of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Co-Principal Executive Officers and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of September 30, 2026 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) is accumulated and communicated to management, including the Co-Principal Executive Officers and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended September 30, 2026 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Annual Report on Form 10-K filed with the SEC on February 19, 2026 and Note 10 in "Item 1. Financial Statements" in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2026.

Additionally, we have received notices of violations and potential fines under various federal, state and local provisions relating to the discharge of materials into the environment or protection of the environment. While we believe that even if any one or more of the following environmental proceedings were decided against us, it would not be material to our financial position, results of operations or cash flows, we are required to report environmental governmental proceedings if we reasonably believe that such proceedings reasonably could result in monetary sanctions in excess of $1 million (previously $0.3 million).

Sunoco LP and certain of its affiliates are defendants in lawsuits alleging liability for climate change impacts from greenhouse gas emissions in Hawaii, Maine and Vermont. Plaintiffs in these cases allege deceptive marketing and concealment of information about these effects, violations of state consumer protection and unfair trade practices laws, and seek certain equitable relief, statutory and civil penalties, punitive damages, disgorgement of profits and attorney's fees. In May 2026, the Hawaii state circuit court denied the defendants' motion to stay the City and County of Honolulu proceedings pending the U.S. Supreme Court's decision in Suncor Energy Inc. v. Board of County Commissioners of Boulder County, which was argued on October 5, 2026, and concerns whether federal law precludes state-law claims of this type. We are unable to estimate the possible loss or range of loss in excess of amounts accrued. Sunoco LP intends to vigorously defend the subject claims.

ITEM 1A. RISK FACTORS

The following is an update to a risk factor that was previously disclosed by the Partnership and should be read in conjunction with our risk factors described in "Part I – Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2025 filed with the SEC on February 19, 2026, as updated by "Part II – Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2026 filed with the SEC on May 7, 2026 and by Exhibit 99.1 to our current report on Form 8-K filed on July 6, 2026.

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

Our common units and Series I Preferred Units are listed on the TXSE. Because we are a publicly traded partnership, the TXSE does not require us to have a majority of independent directors on our general partner's board of directors, or to establish a compensation committee, or a nominating and corporate governance committee. The TXSE also excludes limited partnerships from a number of its other corporate governance requirements applicable to certain other entities. Accordingly, unitholders do not have the same protections afforded to stockholders of certain corporations that are subject to all of the TXSE corporate governance requirements.

ITEM 6. EXHIBITS

The exhibits listed on the following exhibit index are filed or furnished, as indicated, as part of this report:

Exhibit Number	Description
2.1	Plan of Conversion of Energy Transfer LP, dated as of July 2, 2026 (incorporated by reference to Exhibit 2.1 of Form 8-K12B (File No. 1-32740) filed July 6, 2026)
3.1	Certificate of Formation of Energy Transfer LP, dated as of July 6, 2026 (incorporated by reference to Exhibit 3.1 of Form 8-K12B (File No. 1-32740) filed July 6, 2026)
3.2	Agreement of Limited Partnership of Energy Transfer LP, dated as of July 6, 2026 (incorporated by reference to Exhibit 3.2 of Form 8-K12B (File No. 1-32740) filed July 6, 2026)
4.1	Eleventh Supplemental Indenture, dated as of July 20, 2026, between Energy Transfer LP, as issuer, and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-32740) filed July 20, 2026)
4.2	Twelfth Supplemental Indenture, dated as of July 20, 2026, between Energy Transfer LP, as issuer, and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Form 8-K (File No. 1-32740) filed July 20, 2026)
10.1	Form of Commercial Paper Dealer Agreement between Energy Transfer LP, as Issuer, and the Dealer party thereto (incorporated by reference to Exhibit 10.1 of Form 10-Q (File No. 1-32740) filed August 6, 2026)
22.1	Issuers and Guarantors of Registered Securities (incorporated by reference to Exhibit 22.1 of Form 10-Q (File No. 1-32740) filed August 5, 2021)
31.1*	Certification of Co-Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Co-Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.3*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Co-Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Co-Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.3**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets; (ii) our Consolidated Statements of Operations; (iii) our Consolidated Statements of Comprehensive Income; (iv) our Consolidated Statements of Equity; (v) our Consolidated Statements of Cash Flows; and (vi) the notes to our Consolidated Financial Statements
104	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)
*	Filed herewith
**	Furnished herewith

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 thereunto duly authorized.

ENERGY TRANSFER LP

By: LE GP, LLC, its general partner

Date: November 5, 2026

By: /s/ A. Troy Sturrock
A. Troy Sturrock
Group Senior Vice President, Controller and Principal Accounting Officer

Exhibit 31.1

CERTIFICATION OF CO-CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Marshall S. McCrea, III, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 5, 2026

/s/ Marshall S. McCrea, III
Marshall S. McCrea, III
Co-Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CO-CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Thomas E. Long, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 5, 2026

/s/ Thomas E. Long
Thomas E. Long
Co-Chief Executive Officer

Exhibit 31.3

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Dylan A. Bramhall, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 5, 2026

/s/ Dylan A. Bramhall
Dylan A. Bramhall
Executive Vice President and Group Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Energy Transfer LP (the "Partnership") on Form 10-Q for the quarter ended September 30, 2026, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Marshall S. McCrea, III, Co-Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 5, 2026

/s/ Marshall S. McCrea, III
Marshall S. McCrea, III
Co-Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to and will be retained by Energy Transfer LP and furnished to the Securities and Exchange Commission upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Energy Transfer LP (the "Partnership") on Form 10-Q for the quarter ended September 30, 2026, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Thomas E. Long, Co-Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 5, 2026

/s/ Thomas E. Long
Thomas E. Long
Co-Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to and will be retained by Energy Transfer LP and furnished to the Securities and Exchange Commission upon request.

Exhibit 32.3

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Energy Transfer LP (the "Partnership") on Form 10-Q for the quarter ended September 30, 2026, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Dylan A. Bramhall, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 5, 2026

/s/ Dylan A. Bramhall
Dylan A. Bramhall
Executive Vice President and Group Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to and will be retained by Energy Transfer LP and furnished to the Securities and Exchange Commission upon request.