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, 2021

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 Louisiana Street, 10th Floor
Houston, Texas 77002
(Address of Principal Executive Offices, including Zip Code)
(713) 381-6500
(Registrant's Telephone Number, including Area Code)

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange On Which Registered
Common Units	**EPD**	**New York 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 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 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 ☑

There were 2,182,129,957 common units of Enterprise Products Partners L.P. outstanding at the close of business on October 31, 2021.

ENTERPRISE PRODUCTS PARTNERS L.P.
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PART I. FINANCIAL INFORMATION.

ITEM 1. FINANCIAL STATEMENTS.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	September 30, 2021	December 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,213.5	$ 1,059.9
Restricted cash	144.6	98.2
Accounts receivable – trade, net of allowance for credit losses of $50.0 at September 30, 2021 and $46.5 at December 31, 2020	6,119.5	4,802.6
Accounts receivable – related parties	3.0	5.6
Inventories (see Note 3)	3,095.9	3,303.5
Derivative assets (see Note 13)	694.9	228.6
Prepaid and other current assets	557.0	411.0
Total current assets	12,828.4	9,909.4
Property, plant and equipment, net (see Note 4)	42,253.8	41,912.8
Investments in unconsolidated affiliates (see Note 5)	2,433.4	2,429.2
Intangible assets, net (see Note 6)	3,190.0	3,309.1
Goodwill (see Note 6)	5,448.9	5,448.9
Other assets	1,165.4	1,097.3
Total assets	$ 67,319.9	$ 64,106.7
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 7)	$ 1,399.3	$ 1,325.0
Accounts payable – trade	708.1	704.6
Accounts payable – related parties	124.7	149.5
Accrued product payables	7,997.1	5,395.4
Accrued interest	225.2	455.6
Derivative liabilities (see Note 13)	770.1	349.2
Other current liabilities	646.2	608.7
Total current liabilities	11,870.7	8,988.0
Long-term debt (see Note 7)	28,132.8	28,540.7
Deferred tax liabilities (see Note 15)	511.3	464.7
Other long-term liabilities	771.2	686.6
Commitments and contingent liabilities (see Note 16)		
Redeemable preferred limited partner interests: (see Note 8)		
Series A cumulative convertible preferred units (“preferred units”) (50,412 units outstanding at September 30, 2021 and 50,138 units outstanding at December 31, 2020)	49.3	49.3
Equity: (see Note 8)		
Partners’ equity:		
Common limited partner interests (2,182,129,957 units issued and outstanding at September 30, 2021, 2,182,308,958 units issued and outstanding at December 31, 2020)	26,390.3	25,766.6
Treasury units, at cost	(1,297.3)	(1,297.3)
Accumulated other comprehensive loss	(171.8)	(165.2)
Total partners’ equity	24,921.2	24,304.1
Noncontrolling interests in consolidated subsidiaries	1,063.4	1,073.3
Total equity	25,984.6	25,377.4
Total liabilities, preferred units, and equity	$ 67,319.9	$ 64,106.7

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Revenues:				
Third parties	$ 10,800.4	$ 6,914.5	$ 29,382.2	$ 20,126.3
Related parties	30.9	7.5	54.5	29.2
Total revenues (see Note 9)	10,831.3	6,922.0	29,436.7	20,155.5
Costs and expenses:				
Operating costs and expenses:				
Third party and other costs	9,068.1	5,288.2	24,063.9	15,087.4
Related parties	340.4	283.0	964.7	914.5
Total operating costs and expenses	9,408.5	5,571.2	25,028.6	16,001.9
General and administrative costs:				
Third party and other costs	16.4	16.3	56.6	63.1
Related parties	30.9	34.0	98.5	99.7
Total general and administrative costs	47.3	50.3	155.1	162.8
Total costs and expenses (see Note 10)	9,455.8	5,621.5	25,183.7	16,164.7
Equity in income of unconsolidated affiliates	137.6	82.0	447.2	336.1
Operating income	1,513.1	1,382.5	4,700.2	4,326.9
Other income (expense):				
Interest expense	(315.9)	(320.5)	(954.8)	(958.2)
Change in fair market value of Liquidity Option	–	–	–	(2.3)
Interest income	0.9	2.2	2.7	12.3
Other, net	0.1	0.7	(0.1)	2.5
Total other expense, net	(314.9)	(317.6)	(952.2)	(945.7)
Income before income taxes	1,198.2	1,064.9	3,748.0	3,381.2
Benefit from (provision for) income taxes (see Note 15)	(16.1)	19.1	(57.3)	138.6
Net income	1,182.1	1,084.0	3,690.7	3,519.8
Net income attributable to noncontrolling interests	(28.3)	(31.4)	(82.3)	(82.4)
Net income attributable to preferred units	(0.8)	–*	(2.7)	–*
Net income attributable to common unitholders	$ 1,153.0	$ 1,052.6	$ 3,605.7	$ 3,437.4

*Amount is negligible

Earnings per unit: (see Note 11)				
Basic and diluted earnings per common unit	$ 0.52	$ 0.48	$ 1.64	$ 1.56

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
Net income	$ 1,182.1	$ 1,084.0	$ 3,690.7	$ 3,519.8
Other comprehensive income (loss):				
Cash flow hedges: (see Note 13)				
Commodity hedging derivative instruments:				
Changes in fair value of cash flow hedges	(100.6)	(4.2)	(852.2)	392.7
Reclassification of losses (gains) to net income	117.1	29.5	633.8	(334.8)
Interest rate hedging derivative instruments:				
Changes in fair value of cash flow hedges	–	62.6	182.9	(207.7)
Reclassification of losses to net income	10.3	9.9	29.1	29.2
Total cash flow hedges	26.8	97.8	(6.4)	(120.6)
Other	0.1	–	(0.2)	(0.1)
Total other comprehensive income (loss)	26.9	97.8	(6.6)	(120.7)
Comprehensive income	1,209.0	1,181.8	3,684.1	3,399.1
Comprehensive income attributable to noncontrolling interests	(28.3)	(31.4)	(82.3)	(82.4)
Comprehensive income attributable to preferred units	(0.8)	_*	(2.7)	_*
Comprehensive income attributable to common unitholders	$ 1,179.9	$ 1,150.4	$ 3,599.1	$ 3,316.7

*Amount is negligible

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For the Nine Months Ended September 30, 2021	For the Nine Months Ended September 30, 2020
Operating activities:		
Net income	$ 3,690.7	$ 3,519.8
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation and accretion	1,281.0	1,262.6
Amortization of intangible assets	113.3	109.3
Amortization of major maintenance costs for reaction-based plants	19.0	–
Other amortization expense	180.4	173.2
Impairment of assets other than goodwill (see Note 4)	112.9	90.4
Equity in income of unconsolidated affiliates	(447.2)	(336.1)
Distributions received from unconsolidated affiliates attributable to earnings	405.9	337.4
Net losses (gains) attributable to asset sales and related matters	8.4	(2.1)
Deferred income tax expense (benefit)	33.1	(149.0)
Change in fair market value of derivative instruments	(86.3)	(53.7)
Change in fair market value of Liquidity Option	–	2.3
Non-cash expense related to long-term operating leases (see Note 16)	29.5	29.6
Net effect of changes in operating accounts (see Note 17)	1,047.1	(692.0)
Other operating activities	(0.5)	(0.1)
Net cash flows provided by operating activities	6,387.3	4,291.6
Investing activities:		
Capital expenditures	(1,805.7)	(2,671.6)
Investments in unconsolidated affiliates	(1.3)	(9.9)
Distributions received from unconsolidated affiliates attributable to the return of capital	41.2	124.9
Proceeds from asset sales	58.1	8.4
Other investing activities	(13.8)	(16.0)
Cash used in investing activities	(1,721.5)	(2,564.2)
Financing activities:		
Borrowings under debt agreements	11,158.5	6,672.1
Repayments of debt	(11,491.8)	(4,406.6)
Debt issuance costs	(15.1)	(46.3)
Monetization of interest rate derivative instruments	75.2	(33.3)
Cash distributions paid to common unitholders (see Note 8)	(2,948.5)	(2,919.6)
Cash payments made in connection with distribution equivalent rights	(23.1)	(20.0)
Cash distributions paid to noncontrolling interests	(115.1)	(97.8)
Cash contributions from noncontrolling interests	23.0	21.2
Repurchase of common units under 2019 Buyback Program (see Note 8)	(88.8)	(173.8)
Net cash proceeds from the issuance of preferred units	–	32.5
Other financing activities	(40.1)	(34.7)
Cash used in financing activities	(3,465.8)	(1,006.3)
Net change in cash and cash equivalents, including restricted cash	1,200.0	721.1
Cash and cash equivalents, including restricted cash, at beginning of period	1,158.1	410.0
Cash and cash equivalents, including restricted cash, at end of period	$ 2,358.1	$ 1,131.1

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2021
(Dollars in millions)

	Partners' Equity				
	Common Limited Partner Interests	Treasury Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests in Consolidated Subsidiaries	Total
For the Three Months Ended September 30, 2021:					
Balance, June 30, 2021	$ 26,268.8	$ (1,297.3)	$ (198.7)	$ 1,074.0	$ 25,846.8
Net income	1,153.0	–	–	28.3	1,181.3
Cash distributions paid to common unitholders	(983.5)	–	–	–	(983.5)
Cash payments made in connection with distribution equivalent rights	(7.9)	–	–	–	(7.9)
Cash distributions paid to noncontrolling interests	–	–	–	(43.7)	(43.7)
Cash contributions from noncontrolling interests	–	–	–	4.9	4.9
Amortization of fair value of equity-based awards	35.1	–	–	–	35.1
Repurchase and cancellation of common units under 2019 Buyback Program (see Note 8)	(74.9)	–	–	–	(74.9)
Cash flow hedges	–	–	26.8	–	26.8
Other, net	(0.3)	–	0.1	(0.1)	(0.3)
Balance, September 30, 2021	$ 26,390.3	$ (1,297.3)	$ (171.8)	$ 1,063.4	$ 25,984.6

	Partners' Equity				
	Common Limited Partner Interests	Treasury Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests in Consolidated Subsidiaries	Total
For the Nine Months Ended September 30, 2021:					
Balance, December 31, 2020	$ 25,766.6	$ (1,297.3)	$ (165.2)	$ 1,073.3	$ 25,377.4
Net income	3,605.7	–	–	82.3	3,688.0
Cash distributions paid to common unitholders	(2,948.5)	–	–	–	(2,948.5)
Cash payments made in connection with distribution equivalent rights	(23.1)	–	–	–	(23.1)
Cash distributions paid to noncontrolling interests	–	–	–	(115.1)	(115.1)
Cash contributions from noncontrolling interests	–	–	–	23.0	23.0
Amortization of fair value of equity-based awards	114.6	–	–	–	114.6
Repurchase and cancellation of common units under 2019 Buyback Program (see Note 8)	(88.8)	–	–	–	(88.8)
Cash flow hedges	–	–	(6.4)	–	(6.4)
Other, net	(36.2)	–	(0.2)	(0.1)	(36.5)
Balance, September 30, 2021	$ 26,390.3	$ (1,297.3)	$ (171.8)	$ 1,063.4	$ 25,984.6

See Notes to Unaudited Condensed Consolidated Financial Statements. For information regarding Unit History and Accumulated Other Comprehensive Income (Loss), see Note 8.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2020
(Dollars in millions)

	Partners' Equity				
	Common Limited Partner Interests	Treasury Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests in Consolidated Subsidiaries	Total
For the Three Months Ended September 30, 2020:					
Balance, June 30, 2020	$ 26,321.1	$ (1,297.3)	$ (147.1)	$ 1,064.7	$ 25,941.4
Net income	1,052.6	–	–	31.4	1,084.0
Cash distributions paid to common unitholders	(972.7)	–	–	–	(972.7)
Cash payments made in connection with distribution equivalent rights	(7.1)	–	–	–	(7.1)
Cash distributions paid to noncontrolling interests	–	–	–	(36.0)	(36.0)
Cash contributions from noncontrolling interests	–	–	–	1.5	1.5
Amortization of fair value of equity-based awards	39.5	–	–	–	39.5
Repurchase and cancellation of common units under 2019 Buyback Program (see Note 8)	(33.7)	–	–	–	(33.7)
Common units exchanged for preferred units, with common units received being immediately cancelled	(17.5)	–	–	–	(17.5)
Cash flow hedges	–	–	97.8	–	97.8
Other, net	(0.3)	–	–	7.8	7.5
Balance, September 30, 2020	$ 26,381.9	$ (1,297.3)	$ (49.3)	$ 1,069.4	$ 26,104.7

	Partners' Equity				
	Common Limited Partner Interests	Treasury Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests in Consolidated Subsidiaries	Total
For the Nine Months Ended September 30, 2020:					
Balance, December 31, 2019	$ 24,692.6	$ –	$ 71.4	$ 1,063.5	$ 25,827.5
Net income	3,437.4	–	–	82.4	3,519.8
Cash distributions paid to common unitholders	(2,919.6)	–	–	–	(2,919.6)
Cash payments made in connection with distribution equivalent rights	(20.0)	–	–	–	(20.0)
Cash distributions paid to noncontrolling interests	–	–	–	(97.8)	(97.8)
Cash contributions from noncontrolling interests	–	–	–	21.2	21.2
Amortization of fair value of equity-based awards	120.1	–	–	–	120.1
Repurchase and cancellation of common units under 2019 Buyback Program (see Note 8)	(173.8)	–	–	–	(173.8)
Common units issued to Skyline North Americas, Inc. in connection with settlement of Liquidity Option	1,297.3	–	–	–	1,297.3
Treasury units acquired in connection with settlement of Liquidity Option, at cost	–	(1,297.3)	–	–	(1,297.3)
Common units exchanged for preferred units, with common units received being immediately cancelled	(17.5)	–	–	–	(17.5)
Cash flow hedges	–	–	(120.6)	–	(120.6)
Other, net	(34.6)	–	(0.1)	0.1	(34.6)
Balance, September 30, 2020	$ 26,381.9	$ (1,297.3)	$ (49.3)	$ 1,069.4	$ 26,104.7

See Notes to Unaudited Condensed Consolidated Financial Statements. For information regarding Unit History and Accumulated Other Comprehensive Income (Loss), see Note 8.

KEY REFERENCES USED IN THESE NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Unless the context requires otherwise, references to “we,” “us” or “our” within these Notes to Unaudited Condensed Consolidated Financial Statements are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to the “Partnership” mean Enterprise Products Partners L.P. on a standalone basis.

References to “EPO” mean Enterprise Products Operating LLC, which is an indirect wholly owned subsidiary of the Partnership, and its consolidated subsidiaries, through which the Partnership conducts its business. We are managed by our general partner, Enterprise Products Holdings LLC (“Enterprise GP”), which is a wholly owned subsidiary of Dan Duncan LLC, a privately held Texas limited liability company.

The membership interests of Dan Duncan LLC are owned by a voting trust, the current trustees (“DD LLC Trustees”) of which are: (i) Randa Duncan Williams, who is also a director and Chairman of the Board of Directors (the “Board”) of Enterprise GP; (ii) Richard H. Bachmann, who is also a director and Vice Chairman of the Board of Enterprise GP; and (iii) W. Randall Fowler, who is also a director and the Co-Chief Executive Officer and Chief Financial Officer of Enterprise GP. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as managers of Dan Duncan LLC.

References to “EPCO” mean Enterprise Products Company, a privately held Texas corporation, and its privately held affiliates. The outstanding voting capital stock of EPCO is owned by a voting trust, the current trustees (“EPCO Trustees”) of which are: (i) Ms. Duncan Williams, who serves as Chairman of EPCO; (ii) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO; and (iii) Mr. Fowler, who serves as an Executive Vice President and the Chief Financial Officer of EPCO. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as directors of EPCO.

We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. EPCO, together with its privately held affiliates, owned approximately 32.2% of the Partnership’s common units outstanding at September 30, 2021.

With the exception of per unit amounts, or as noted within the context of each disclosure, the dollar amounts presented in the tabular data within these disclosures are stated in millions of dollars.

Note 1. Partnership Organization and Operations

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Our preferred units are not publicly traded. We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products. We are owned by our limited partners (preferred and common unitholders) from an economic perspective. Enterprise GP, which owns a non-economic general partner interest in us, manages our Partnership. We conduct substantially all of our business operations through EPO and its consolidated subsidiaries.

Our fully integrated, midstream energy asset network (or "value chain") links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and the Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include:

- natural gas gathering, treating, processing, transportation and storage;
- NGL transportation, fractionation, storage, and marine terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane);
- crude oil gathering, transportation, storage, and marine terminals;
- propylene production facilities (including propane dehydrogenation ("PDH") facilities), butane isomerization, octane enhancement, isobutane dehydrogenation ("iBDH") and high purity isobutylene ("HPIB") production facilities;
- petrochemical and refined products transportation, storage, and marine terminals (including those used to export ethylene and polymer grade propylene ("PGP")); and
- a marine transportation business that operates on key U.S. inland and intracoastal waterway systems.

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. See Note 14 for information regarding related party matters.

Our results of operations for the nine months ended September 30, 2021 are not necessarily indicative of results expected for the full year of 2021. In our opinion, the accompanying Unaudited Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate and make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with United States ("U.S.") generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC").

These Unaudited Condensed Consolidated Financial Statements and Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2020 (the "2020 Form 10-K") filed with the SEC on March 1, 2021.

Note 2. Summary of Significant Accounting Policies

Apart from those matters described in this footnote, there have been no updates to our significant accounting policies since those reported under Note 2 of the 2020 Form 10-K.

Allowance for Credit Losses

We estimate our allowance for credit losses (formerly, the allowance for doubtful accounts) at each reporting date using a current expected credit loss model, which requires the measurement of expected credit losses for financial assets (e.g., accounts receivable) based on historical experience with customers, current economic conditions, and reasonable and supportable forecasts. We may also increase the allowance for credit losses in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties.

The following table presents our allowance for credit losses activity since December 31, 2020:

Allowance for credit losses, December 31, 2020	$ 46.5
Charged to costs and expenses	2.5
Charged to other accounts	4.4
Deductions	(3.4)
Allowance for credit losses, September 30, 2021	$ 50.0

Cash, Cash Equivalents and Restricted Cash

The following table provides a reconciliation of cash and cash equivalents, and restricted cash reported within the Unaudited Condensed Consolidated Balance Sheets that sum to the total of the amounts shown in the Unaudited Condensed Statements of Consolidated Cash Flows.

	September 30, 2021	December 31, 2020
Cash and cash equivalents	$ 2,213.5	$ 1,059.9
Restricted cash	144.6	98.2
Total cash, cash equivalents and restricted cash shown in the Unaudited Condensed Statements of Consolidated Cash Flows	$ 2,358.1	$ 1,158.1

Restricted cash primarily represents amounts held in segregated bank accounts by our clearing brokers as margin in support of our commodity derivative instruments portfolio and related physical purchases and sales of natural gas, NGLs, crude oil, refined products and power. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or margin requirements change. See Note 13 for information regarding our derivative instruments and hedging activities.

Note 3. Inventories

Our inventory amounts by product type were as follows at the dates indicated:

	September 30, 2021	December 31, 2020
NGLs	$ 2,500.8	$ 1,888.1
Petrochemicals and refined products	368.9	642.6
Crude oil	201.3	758.1
Natural gas	24.9	14.7
Total	$ 3,095.9	$ 3,303.5

Due to fluctuating commodity prices, we recognize lower of cost or net realizable value adjustments when the carrying value of our available-for-sale inventories exceeds their net realizable value. The following table presents our total cost of sales amounts and lower of cost or net realizable value adjustments for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Cost of sales (1)	$ 8,112.8	$ 4,313.7	$ 21,215.8	$ 12,331.9
Lower of cost or net realizable value adjustments recognized in cost of sales	1.3	4.4	14.2	55.6

(1) Cost of sales is a component of "Operating costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations. Fluctuations in these amounts are primarily due to changes in energy commodity prices and sales volumes associated with our marketing activities.

Note 4. Property, Plant and Equipment

The historical costs of our property, plant and equipment and related balances were as follows at the dates indicated:

	Estimated Useful Life in Years	September 30, 2021	December 31, 2020
Plants, pipelines and facilities (1)	3-45(5)	$ 50,766.1	$ 49,972.8
Underground and other storage facilities (2)	5-40(6)	4,281.2	4,207.5
Transportation equipment (3)	3-10	208.2	204.9
Marine vessels (4)	15-30	941.8	932.7
Land		383.0	371.9
Construction in progress		2,182.6	1,807.7
Subtotal		58,762.9	57,497.5
Less accumulated depreciation		16,593.1	15,584.7
Subtotal property, plant and equipment, net		42,169.8	41,912.8
Capitalized major maintenance costs for reaction-based plants, net of accumulated amortization (7)		84.0	–
Property, plant and equipment, net		$ 42,253.8	$ 41,912.8

(1) Plants, pipelines and facilities include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; buildings; office furniture and equipment; laboratory and shop equipment and related assets.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(4) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(5) In general, the estimated useful lives of major assets within this category are: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; buildings, 20-40 years; office furniture and equipment, 3-20 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.
(7) For reaction-based plants, we use the deferral method when accounting for major maintenance activities. Under the deferral method, major maintenance costs are capitalized and amortized over the period until the next major overhaul project. On a weighted-average basis, the expected amortization period for these costs is 2.6 years.

Property, plant and equipment at September 30, 2021 and December 31, 2020 includes $79.1 million and $69.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our asset retirement obligations, or AROs, since December 31, 2020:

ARO liability balance, December 31, 2020	$ 149.5
Liabilities incurred (1)	6.5
Revisions in estimated cash flows (2)	3.9
Liabilities settled (3)	(0.7)
Accretion expense (4)	8.0
ARO liability balance, September 30, 2021	$ 167.2

(1) Represents the initial recognition of estimated ARO liabilities during period.
(2) Represents subsequent adjustments to estimated ARO liabilities during period.
(3) Represents cash payments to settle ARO liabilities during period.
(4) Represents net change in ARO liability balance attributable to the passage of time and other adjustments, including true-up amounts associated with revised closure estimates.

Of the $167.2 million total ARO liability recorded at September 30, 2021, $12.9 million was reflected as a current liability and $154.3 million as a long-term liability.

The following table summarizes our depreciation and accretion expense and capitalized interest amounts for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Depreciation expense (1)	$ 425.3	$ 420.7	$ 1,273.0	$ 1,251.6
Accretion expense (1)	4.2	0.8	8.0	11.0
Capitalized interest (2)	23.0	34.5	63.8	96.9

(1) Depreciation and accretion expense is a component of “Third party and other costs” within “Costs and expenses” as presented on our Unaudited Condensed Statements of Consolidated Operations.
(2) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset’s estimated useful life as a component of depreciation expense. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise.

Asset impairment charges

In March 2021, we entered into agreements to sell a coal bed natural gas gathering system and related Val Verde treating facility, both of which were components of our San Juan Gathering System, to a third party for $39.1 million in cash. The transaction closed and was effective on April 1, 2021. We recognized an impairment charge of $44.3 million attributable to this transaction, which reflects the write down of $37.5 million of property, plant and equipment and $6.8 million of intangible assets (see Note 6) to their respective fair values. The remainder of our impairment charges for the nine month periods ended September 30, 2021 and 2020 are attributable to the complete write-off of assets that are no longer expected to be used or constructed.

Asset impairment charges related to operations are a component of “Third party and other costs” within “Operating costs and expenses” as presented on our Unaudited Condensed Statements of Consolidated Operations.

We are closely monitoring the recoverability of our long-lived assets, investments in unconsolidated affiliates and goodwill in light of the adverse economic effects of the coronavirus disease 2019 (“COVID-19”) pandemic. If the adverse economic impacts of the pandemic persist for longer periods than currently expected, these developments could result in the recognition of non-cash impairment charges in the future.

Note 5. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. We account for these investments using the equity method.

	September 30, 2021	December 31, 2020
NGL Pipelines & Services	$ 656.4	$ 671.6
Crude Oil Pipelines & Services	1,742.1	1,723.7
Natural Gas Pipelines & Services	32.1	31.4
Petrochemical & Refined Products Services	2.8	2.5
Total	$ 2,433.4	$ 2,429.2

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
NGL Pipelines & Services	$ 30.5	$ 29.3	$ 87.5	$ 90.8
Crude Oil Pipelines & Services	105.2	51.8	354.2	243.2
Natural Gas Pipelines & Services	1.4	1.4	4.3	4.3
Petrochemical & Refined Products Services	0.5	(0.5)	1.2	(2.2)
Total	$ 137.6	$ 82.0	$ 447.2	$ 336.1

Note 6. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets by business segment at the dates indicated:

	September 30, 2021			December 31, 2020		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 447.8	$ (231.3)	$ 216.5	$ 447.8	$ (221.3)	$ 226.5
Contract-based intangibles	166.0	(59.3)	106.7	162.6	(55.0)	107.6
Segment total	613.8	(290.6)	323.2	610.4	(276.3)	334.1
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,195.0	(339.2)	1,855.8	2,195.0	(291.6)	1,903.4
Contract-based intangibles	283.1	(259.5)	23.6	283.1	(249.9)	33.2
Segment total	2,478.1	(598.7)	1,879.4	2,478.1	(541.5)	1,936.6
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,350.3	(541.1)	809.2	1,350.3	(512.2)	838.1
Contract-based intangibles	231.1	(181.2)	49.9	470.7	(403.8)	66.9
Segment total	1,581.4	(722.3)	859.1	1,821.0	(916.0)	905.0
Petrochemical & Refined Products Services:						
Customer relationship intangibles	181.4	(72.4)	109.0	181.4	(68.3)	113.1
Contract-based intangibles	44.9	(25.6)	19.3	44.9	(24.6)	20.3
Segment total	226.3	(98.0)	128.3	226.3	(92.9)	133.4
Total intangible assets	$ 4,899.6	$ (1,709.6)	$ 3,190.0	$ 5,135.8	$ (1,826.7)	$ 3,309.1

The following table presents the amortization expense of our intangible assets by business segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
NGL Pipelines & Services	$ 6.2	$ 6.2	$ 18.3	$ 19.0
Crude Oil Pipelines & Services	20.3	16.0	57.2	55.7
Natural Gas Pipelines & Services	11.5	9.0	32.7	28.8
Petrochemical & Refined Products Services	1.7	1.9	5.1	5.8
Total	$ 39.7	$ 33.1	$ 113.3	$ 109.3

The following table presents our forecast of amortization expense associated with existing intangible assets for the periods indicated:

Remainder of 2021	2022	2023	2024	2025
$ 37.4	$ 169.6	$ 173.8	$ 177.9	$ 174.4

Impairment of Intangible Asset

In March 2021, we recognized an impairment charge of $6.8 million for the write down of contract-based intangible assets associated with the sale of a portion of our San Juan Gathering System (see Note 4). The contract-based intangible assets were classified within our Natural Gas Pipelines & Services business segment.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. There has been no change in our goodwill amounts since those reported in our 2020 Form 10-K. We are closely monitoring the recoverability of our long-lived assets, which include goodwill, in light of the COVID-19 pandemic.

Note 7. Debt Obligations

The following table presents our consolidated debt obligations (arranged by company and maturity date) at the dates indicated:

	September 30, 2021	December 31, 2020
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$ –	$ –
Senior Notes TT, 2.80% fixed-rate, due February 2021	–	750.0
Senior Notes RR, 2.85% fixed-rate, due April 2021	–	575.0
Senior Notes VV, 3.50% fixed-rate, due February 2022	750.0	750.0
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0	650.0
September 2021 364-Day Revolving Credit Agreement, variable-rate, due September 2022	–	–
Senior Notes HH, 3.35% fixed-rate, due March 2023	1,250.0	1,250.0
Senior Notes JJ, 3.90% fixed-rate, due February 2024	850.0	850.0
Senior Notes MM, 3.75% fixed-rate, due February 2025	1,150.0	1,150.0
Senior Notes PP, 3.70% fixed-rate, due February 2026	875.0	875.0
September 2021 Multi-Year Revolving Credit Agreement, variable-rate, due September 2026	–	–
Senior Notes SS, 3.95% fixed-rate, due February 2027	575.0	575.0
Senior Notes WW, 4.15% fixed-rate, due October 2028	1,000.0	1,000.0
Senior Notes YY, 3.125% fixed-rate, due July 2029	1,250.0	1,250.0
Senior Notes AAA, 2.80% fixed-rate, due January 2030	1,250.0	1,250.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0	750.0
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0	1,100.0
Senior Notes II, 4.85% fixed-rate, due March 2044	1,400.0	1,400.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0	1,150.0
Senior Notes QQ, 4.90% fixed-rate, due May 2046	975.0	975.0
Senior Notes UU, 4.25% fixed-rate, due February 2048	1,250.0	1,250.0
Senior Notes XX, 4.80% fixed-rate, due February 2049	1,250.0	1,250.0
Senior Notes ZZ, 4.20% fixed-rate, due January 2050	1,250.0	1,250.0
Senior Notes BBB, 3.70% fixed-rate, due January 2051	1,000.0	1,000.0
Senior Notes DDD, 3.20% fixed-rate, due February 2052	1,000.0	1,000.0
Senior Notes EEE, 3.30% fixed-rate, due February 2053	1,000.0	–
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0	400.0
Senior Notes CCC, 3.95% fixed rate, due January 2060	1,000.0	1,000.0
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	27,175.0	27,500.0
EPO Junior Subordinated Notes C, variable-rate, due June 2067 (1)	232.2	232.2
EPO Junior Subordinated Notes D, fixed/variable-rate, due August 2077 (2)	700.0	700.0
EPO Junior Subordinated Notes E, fixed/variable-rate, due August 2077 (3)	1,000.0	1,000.0
EPO Junior Subordinated Notes F, fixed/variable-rate, due February 2078 (4)	700.0	700.0
TEPPCO Junior Subordinated Notes, variable-rate, due June 2067 (1)	14.2	14.2
Total principal amount of senior and junior debt obligations	29,821.4	30,146.4
Other, non-principal amounts	(289.3)	(280.7)
Less current maturities of debt	(1,399.3)	(1,325.0)
Total long-term debt	$ 28,132.8	$ 28,540.7

(1) Variable rate is reset quarterly and based on 3-month London Interbank Offered Rate ("LIBOR"), plus 2.778%.
(2) Fixed rate of 4.875% through August 15, 2022; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.986%.
(3) Fixed rate of 5.250% through August 15, 2027; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 3.033%.
(4) Fixed rate of 5.375% through February 14, 2028; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.57%.

References to "TEPPCO" mean TEPPCO Partners, L.P. prior to its merger with one of our wholly owned subsidiaries in October 2009.

Variable Interest Rates

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the nine months ended September 30, 2021:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	0.15% to 0.25%	0.21%
EPO Junior Subordinated Notes C and TEPPCO Junior Subordinated Notes	2.90% to 3.00%	2.95%

Amounts borrowed under EPO's September 2021 364-Day Revolving Credit Agreement and September 2021 Multi-Year Revolving Credit Agreement bear interest, at its election, equal to: (i) LIBOR, plus an additional variable spread; or (ii) an alternate base rate, which is the greatest of (a) the Prime Rate in effect on such day, (b) the Federal Funds Effective Rate in effect on such day plus 0.5%, or (c) LIBOR for an interest period of one month in effect on such day plus 1%, and a variable spread. The applicable spreads are determined based on EPO's debt ratings.

In July 2017, the Financial Conduct Authority in the U.K. announced a desire to phase out LIBOR as a benchmark by the end of June 2023. Financial industry working groups are developing replacement rates and methodologies to transition existing agreements that depend on LIBOR as a reference rate. We currently do not expect the transition from LIBOR to have a material financial impact on us.

Scheduled Maturities of Debt

The following table presents the scheduled maturities of principal amounts of EPO's consolidated debt obligations at September 30, 2021 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	Remainder of 2021	2022	2023	2024	2025	Thereafter
Senior Notes	$ 27,175.0	$ –	$ 1,400.0	$ 1,250.0	$ 850.0	$ 1,150.0	$ 22,525.0
Junior Subordinated Notes	2,646.4	–	–	–	–	–	2,646.4
Total	$ 29,821.4	$ –	$ 1,400.0	$ 1,250.0	$ 850.0	$ 1,150.0	$ 25,171.4

In February 2021, EPO repaid all of the $750.0 million in principal amount of its Senior Notes TT using remaining cash on hand attributable to its August 2020 senior notes offering and proceeds from the issuance of short-term notes under its commercial paper program.

In March 2021, EPO redeemed all of the $575.0 million outstanding principal amount of its Senior Notes RR one month prior to their scheduled maturity in April 2021. These notes were redeemed at par (i.e., at a redemption price equal to the outstanding principal amount of such notes to be redeemed, plus accrued and unpaid interest thereon) using proceeds from the issuance of short-term notes under its commercial paper program.

September 2021 364-Day Revolving Credit Agreement

In September 2021, EPO entered into a new 364-Day Revolving Credit Agreement (the "September 2021 364-Day Revolving Credit Agreement") that replaced its September 2020 364-Day Revolving Credit Agreement. There were no principal amounts outstanding under the September 2020 364-Day Revolving Credit Agreement when it was replaced by the September 2021 364-Day Revolving Credit Agreement. At September 30, 2021, there were no principal amounts outstanding under the September 2021 364-Day Revolving Credit Agreement.

Under the terms of the September 2021 364-Day Revolving Credit Agreement, EPO may borrow up to $1.5 billion (which may be increased by up to $200.0 million to $1.7 billion at EPO's election, provided certain conditions are met) at a variable interest rate for a term of up to 364 days, subject to the terms and conditions set forth therein. The September 2021 364-Day Revolving Credit Agreement matures in September 2022. To the extent that principal amounts are outstanding at the maturity date, EPO may elect to have the entire principal balance then outstanding continued as non-revolving term loans for a period of one additional year, payable in September 2023. Borrowings under the September 2021 364-Day Revolving Credit Agreement may be used for working capital, capital expenditures, acquisitions and general company purposes.

The September 2021 364-Day Revolving Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of any amounts borrowed under this credit agreement. The September 2021 364-Day Revolving Credit Agreement also restricts EPO's ability to pay cash distributions to the Partnership, if an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid or would result therefrom.

EPO's obligations under the September 2021 364-Day Revolving Credit Agreement are not secured by any collateral; however, they are guaranteed by the Partnership.

September 2021 Multi-Year Revolving Credit Agreement

In September 2021, EPO entered into a new revolving credit agreement that matures in September 2026 (the "September 2021 Multi-Year Revolving Credit Agreement"). The September 2021 Multi-Year Revolving Credit Agreement replaced EPO's prior multi-year revolving credit agreement that was scheduled to mature in September 2024. There were no principal amounts outstanding under the prior multi-year revolving credit agreement when it was replaced by the September 2021 Multi Year Revolving Credit Agreement. At September 30, 2021, there were no principal amounts outstanding under the September 2021 Multi-Year Revolving Credit Agreement.

Under the terms of the September 2021 Multi-Year Revolving Credit Agreement, EPO may borrow up to $3.0 billion (which may be increased by up to $500.0 million to $3.5 billion at EPO's election, provided certain conditions are met) at a variable interest rate for a term of five years, subject to the terms and conditions set forth therein. Borrowings under the September 2021 Multi-Year Revolving Credit Agreement may be used as a backstop for commercial paper and for working capital, capital expenditures, acquisitions and general company purposes.

The September 2021 Multi-Year Revolving Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of any amounts borrowed under this credit agreement. The September 2021 Multi-Year Revolving Credit Agreement also restricts EPO's ability to pay cash distributions to the Partnership, if an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid or would result therefrom.

EPO's obligations under the September 2021 Multi-Year Revolving Credit Agreement are not secured by any collateral; however, they are guaranteed by the Partnership.

September 2021 Senior Notes Offering

In September 2021, EPO issued $1.0 billion in principal amount of senior notes due February 2053 ("Senior Notes EEE"). Senior Notes EEE were issued at 99.170% of their principal amount and have a fixed rate of interest of 3.30% per year.

Net proceeds from the issuance of these senior notes will be used for general company purposes, including for growth capital investments, and the repayment of debt (including the repayment of a portion of our $750.0 million in principal amount of 3.50% Senior Notes VV and/or a portion of our $650.0 million in principal amount of 4.05% Senior Notes CC, in each case at their maturity in February 2022).

EPO's fixed-rate senior notes are unsecured obligations of EPO that rank equal with its existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. EPO's senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict its ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

Letters of Credit

At September 30, 2021, EPO had $88.0 million of letters of credit outstanding primarily related to our commodity hedging activities.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at September 30, 2021.

Parent-Subsidiary Guarantor Relationships

The Partnership acts as guarantor of the consolidated debt obligations of EPO, with the exception of the remaining debt obligations of TEPPCO. If EPO were to default on any of its guaranteed debt, the Partnership would be responsible for full and unconditional repayment of such obligations.

Note 8. Capital Accounts

Common Limited Partner Interests

The following table summarizes changes in the number of our common units outstanding since December 31, 2020:

Common units outstanding at December 31, 2020	2,182,308,958
Common unit repurchases under 2019 Buyback Program	(709,816)
Common units issued in connection with the vesting of phantom unit awards, net	3,553,313
Other	26,148
Common units outstanding at March 31, 2021	2,185,178,603
Common units issued in connection with the vesting of phantom unit awards, net	203,066
Common units outstanding at June 30, 2021	2,185,381,669
Common unit repurchases under 2019 Buyback Program	(3,367,377)
Common units issued in connection with the vesting of phantom unit awards, net	115,665
Common units outstanding at September 30, 2021	2,182,129,957

Registration Statements
We have a universal shelf registration statement (the "2019 Shelf") on file with the SEC which allows the Partnership and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

In addition, the Partnership has a registration statement on file with the SEC covering the issuance of up to $2.54 billion of its common units in amounts, at prices and on terms based on market conditions and other factors at the time of such offerings (referred to as the Partnership's at-the-market ("ATM") program). The Partnership did not issue any common units under its ATM program during the nine months ended September 30, 2021. The Partnership's capacity to issue additional common units under the ATM program remains at $2.54 billion as of September 30, 2021.

We may issue additional equity and debt securities to assist us in meeting our future liquidity requirements, including those related to capital investments.

Common Unit Repurchases Under 2019 Buyback Program
In January 2019, we announced that the Board of Enterprise GP had approved a $2.0 billion multi-year unit buyback program (the "2019 Buyback Program"), which provides the Partnership with an additional method to return capital to investors. The 2019 Buyback Program authorizes the Partnership to repurchase its common units from time to time, including through open market purchases and negotiated transactions. No time limit has been set for completion of the program, and it may be suspended or discontinued at any time.

The Partnership repurchased an aggregate 3,367,377 and 4,077,193 common units through open market purchases during the three and nine months ended September 30, 2021, respectively. The total cost of these repurchases, including commissions and fees, was $74.9 million and $88.8 million, respectively. During the three and nine months ended September 30, 2020, the Partnership repurchased 1,984,507 and 8,342,246 common units, respectively, under the 2019 Buyback Program. The total cost of these repurchases, including commissions and fees, was $33.7 million and $173.8 million, respectively. Units repurchased under the 2019 Buyback Program are immediately cancelled upon acquisition. At September 30, 2021, the remaining available capacity under the 2019 Buyback Program was $1.64 billion.

Common Units Issued in Connection With the Vesting of Phantom Unit Awards
After taking into account tax withholding requirements, the Partnership issued 3,872,044 new common units to employees in connection with the vesting of phantom unit awards during the nine months ended September 30, 2021. See Note 12 for information regarding our phantom unit awards.

Common Units Delivered Under DRIP and EUPP
The Partnership has registration statements on file with the SEC in connection with its distribution reinvestment plan ("DRIP") and employee unit purchase plan ("EUPP"). In July 2019, the Partnership announced that, beginning with the quarterly distribution payment paid in August 2019, it would use common units purchased on the open market, rather than issuing new common units, to satisfy its delivery obligations under the DRIP and EUPP. This election is subject to change in future quarters depending on the Partnership's need for equity capital.

During the nine months ended September 30, 2021, agents of the Partnership purchased 4,754,016 common units on the open market and delivered them to participants in the DRIP and EUPP. Apart from $2.9 million attributable to the plan discount available to all participants in the EUPP, the funds used to effect these purchases were sourced from the DRIP and EUPP participants. No other Partnership funds were used to satisfy these obligations. We plan to use open market purchases to satisfy DRIP and EUPP reinvestments in connection with the distribution expected to be paid on November 12, 2021.

Preferred Units

The following table summarizes changes in the number of our Series A Cumulative Convertible Preferred Units ("preferred units") outstanding since December 31, 2020:

Preferred units outstanding at December 31, 2020	50,138
Paid in-kind distribution to related party	274
Preferred units outstanding at March 31, 2021, June 30, 2021 and September 30, 2021	50,412

We present the capital accounts attributable to our preferred unitholders as mezzanine equity on our consolidated balance sheets since the terms of the preferred units allow for cash redemption by such unitholders in the event of a Change of Control (as defined in our partnership agreement), without regard to the likelihood of such an event.

During the nine months ended September 30, 2021, the Partnership made quarterly distributions to its third party and related party preferred unitholders valued at $2.8 million, consisting of paid-in-kind distributions of 274 new preferred units and $2.5 million of cash.

In March 2021, a privately held affiliate of EPCO sold its entire ownership interest in the Partnership's preferred units to third parties.

Accumulated Other Comprehensive Income (Loss)

The following tables present the components of accumulated other comprehensive income (loss) as reported on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

	Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Accumulated Other Comprehensive Income (Loss), December 31, 2020	$ (93.2)	$ (74.3)	$ 2.3	$ (165.2)
Other comprehensive income (loss) for period, before reclassifications	(852.2)	182.9	(0.3)	(669.6)
Reclassification of losses to net income during period	633.8	29.1	0.1	663.0
Total other comprehensive income (loss) for period	(218.4)	212.0	(0.2)	(6.6)
Accumulated Other Comprehensive Income (Loss), September 30, 2021	$ (311.6)	$ 137.7	$ 2.1	$ (171.8)

	Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Accumulated Other Comprehensive Income, December 31, 2019	$ 55.1	$ 13.9	$ 2.4	$ 71.4
Other comprehensive income (loss) for period, before reclassifications	392.7	(207.7)	(0.1)	184.9
Reclassification of losses (gains) to net income during period	(334.8)	29.2	–	(305.6)
Total other comprehensive income (loss) for period	57.9	(178.5)	(0.1)	(120.7)
Accumulated Other Comprehensive Income (Loss), September 30, 2020	$ 113.0	$ (164.6)	$ 2.3	$ (49.3)

The following table presents reclassifications of (income) loss out of accumulated other comprehensive income into net income during the periods indicated:

		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Losses (gains) on cash flow hedges:	**Location**	**2021**	**2020**	**2021**	**2020**
Interest rate derivatives	Interest expense	$ 10.3	$ 9.9	$ 29.1	$ 29.2
Commodity derivatives	Revenue	116.8	19.5	614.9	(344.7)
Commodity derivatives	Operating costs and expenses	0.3	10.0	18.9	9.9
Total		$ 127.4	$ 39.4	$ 662.9	$ (305.6)

For information regarding our interest rate and commodity derivative instruments, see Note 13.

Cash Distributions

On October 12, 2021, we announced that the Board declared a quarterly cash distribution of $0.45 per common unit, or $1.80 per common unit on an annualized basis, to be paid to the Partnership's common unitholders with respect to the third quarter of 2021. The quarterly distribution is payable on November 12, 2021 to unitholders of record as of the close of business on October 29, 2021. The total amount to be paid is $989.7 million, which includes $7.8 million for distribution equivalent rights ("DERs") on phantom unit awards.

The payment of quarterly cash distributions is subject to management's evaluation of our financial condition, results of operations and cash flows in connection with such payments and Board approval. In light of current economic conditions, management will evaluate any future increases in cash distributions on a quarterly basis.

Note 9. Revenues

We classify our revenues into sales of products and midstream services. Product sales relate primarily to our various marketing activities whereas midstream services represent our other integrated businesses (i.e., gathering, processing, transportation, fractionation, storage and terminaling). The following table presents our revenues by business segment, and further by revenue type, for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,169.6	$ 2,048.4	$ 9,151.0	$ 6,401.7
Segment midstream services:				
Natural gas processing and fractionation	253.6	205.4	688.5	575.8
Transportation	235.0	254.7	745.1	769.6
Storage and terminals	158.4	105.5	402.6	311.3
Total segment midstream services	647.0	565.6	1,836.2	1,656.7
Total NGL Pipelines & Services	3,816.6	2,614.0	10,987.2	8,058.4
Crude Oil Pipelines & Services:				
Sales of crude oil	2,890.0	1,216.1	6,868.2	4,059.7
Segment midstream services:				
Transportation	232.9	189.3	691.4	603.5
Storage and terminals	111.7	116.2	344.0	360.5
Total segment midstream services	344.6	305.5	1,035.4	964.0
Total Crude Oil Pipelines & Services	3,234.6	1,521.6	7,903.6	5,023.7
Natural Gas Pipelines & Services:				
Sales of natural gas	732.2	350.7	2,543.1	1,097.6
Segment midstream services:				
Transportation	247.7	256.2	732.7	765.1
Total segment midstream services	247.7	256.2	732.7	765.1
Total Natural Gas Pipelines & Services	979.9	606.9	3,275.8	1,862.7
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	2,537.8	1,966.2	6,523.6	4,593.7
Segment midstream services:				
Fractionation and isomerization	81.0	54.6	214.6	129.0
Transportation, including marine logistics	116.2	115.2	357.1	365.5
Storage and terminals	65.2	43.5	174.8	122.5
Total segment midstream services	262.4	213.3	746.5	617.0
Total Petrochemical & Refined Products Services	2,800.2	2,179.5	7,270.1	5,210.7
Total consolidated revenues	$ 10,831.3	$ 6,922.0	$ 29,436.7	$ 20,155.5

Substantially all of our revenues are derived from contracts with customers as defined within ASC 606, *Revenue from Contracts with Customers*.

Unbilled Revenue and Deferred Revenue

The following table provides information regarding our contract assets and contract liabilities at September 30, 2021:

Contract Asset	Location	Balance
Unbilled revenue (current amount)	Prepaid and other current assets	$ 164.9
Total		$ 164.9

Contract Liability	Location	Balance
Deferred revenue (current amount)	Other current liabilities	$ 164.9
Deferred revenue (noncurrent)	Other long-term liabilities	238.5
Total		$ 403.4

The following table presents significant changes in our unbilled revenue and deferred revenue balances for the nine months ended September 30, 2021:

	Unbilled Revenue	Deferred Revenue
Balance at December 31, 2020	$ 18.8	$ 343.5
Amount included in opening balance transferred to other accounts during period (1)	(18.8)	(134.4)
Amount recorded during period (2)	199.9	686.6
Amounts recorded during period transferred to other accounts (1)	(35.0)	(481.4)
Other changes	–	(10.9)
Balance at September 30, 2021	$ 164.9	$ 403.4

(1) Unbilled revenues are transferred to accounts receivable once we have an unconditional right to consideration from the customer. Deferred revenues are recognized as revenue upon satisfaction of our performance obligation to the customer.
(2) Unbilled revenue represents revenue that has been recognized upon satisfaction of a performance obligation, but cannot be contractually invoiced (or billed) to the customer at the balance sheet date until a future period. Deferred revenue is recorded when payment is received from a customer prior to our satisfaction of the associated performance obligation.

Remaining Performance Obligations

The following table presents estimated fixed future consideration from revenue contracts that contain minimum volume commitments, deficiency and similar fees and the term of the contracts exceeds one year. These amounts represent the revenues we expect to recognize in future periods from these contracts as of September 30, 2021.

Period	Fixed Consideration
Three Months Ended December 31, 2021	$ 1,003.5
One Year Ended December 31, 2022	3,589.2
One Year Ended December 31, 2023	3,025.5
One Year Ended December 31, 2024	2,830.8
One Year Ended December 31, 2025	2,476.9
Thereafter	11,113.3
Total	$ 24,039.2

Note 10. Business Segments and Related Information

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold.

Financial information regarding these segments is evaluated regularly by our co-chief operating decision makers in deciding how to allocate resources and in assessing our operating and financial performance. The co-principal executive officers of our general partner have been identified as our co-chief operating decision makers. While these two officers evaluate results in a number of different ways, the business segment structure is the primary basis for which the allocation of resources and financial results are assessed.

The following information summarizes the assets and operations of each business segment:

- Our NGL Pipelines & Services business segment includes our natural gas processing and related NGL marketing activities, NGL pipelines, NGL fractionation facilities, NGL and related product storage facilities, and NGL marine terminals.

- Our Crude Oil Pipelines & Services business segment includes our crude oil pipelines, crude oil storage and marine terminals, and related crude oil marketing activities.

- Our Natural Gas Pipelines & Services business segment includes our natural gas pipeline systems that provide for the gathering, treating and transportation of natural gas. This segment also includes our natural gas marketing activities.

- Our Petrochemical & Refined Products Services business segment includes our (i) propylene production facilities, which include propylene fractionation units and a PDH facility, and related pipelines and marketing activities, (ii) butane isomerization complex and related deisobutanizer operations, (iii) octane enhancement, iBDH and HPIB production facilities, (iv) refined products pipelines, terminals and related marketing activities, (v) ethylene export terminal and related operations; and (vi) marine transportation business.

Segment Gross Operating Margin

We evaluate segment performance based on our financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. Gross operating margin is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests. Our calculation of gross operating margin may or may not be comparable to similarly titled measures used by other companies.

The following table presents our measurement of total segment gross operating margin for the periods presented. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
Operating income	$ 1,513.1	$ 1,382.5	$ 4,700.2	$ 4,326.9
Adjustments to reconcile operating income to total segment gross operating margin (addition or subtraction indicated by sign):				
Depreciation, amortization and accretion expense in operating costs and expenses (1)	502.7	484.2	1,497.9	1,461.3
Asset impairment charges in operating costs and expenses	29.3	77.0	112.7	90.4
Net losses (gains) attributable to asset sales and related matters in operating costs and expenses	(2.2)	(0.6)	9.0	(2.1)
General and administrative costs	47.3	50.3	155.1	162.8
Non-refundable payments received from shippers attributable to make-up rights (2)	25.4	49.3	67.0	79.1
Subsequent recognition of revenues attributable to make-up rights (3)	(35.2)	(9.4)	(113.4)	(25.0)
Total segment gross operating margin	$ 2,080.4	$ 2,033.3	$ 6,428.5	$ 6,093.4

(1) Excludes amortization of major maintenance costs for reaction-based plants, which are a component of gross operating margin.
(2) Since make-up rights entail a future performance obligation by the pipeline to the shipper, these receipts are recorded as deferred revenue for GAAP purposes; however, these receipts are included in gross operating margin in the period of receipt since they are nonrefundable to the shipper.
(3) As deferred revenues attributable to make-up rights are subsequently recognized as revenue under GAAP, gross operating margin must be adjusted to remove such amounts to prevent duplication since the associated non-refundable payments were previously included in gross operating margin.

Gross operating margin by segment is calculated by subtracting segment operating costs and expenses from segment revenues, with both segment totals reflecting the adjustments noted in the preceding table, as applicable, and before the elimination of intercompany transactions. The following table presents gross operating margin by segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
Gross operating margin by segment:				
NGL Pipelines & Services	$ 1,022.9	$ 1,028.1	$ 3,206.9	$ 3,038.2
Crude Oil Pipelines & Services	422.9	481.8	1,242.0	1,569.1
Natural Gas Pipelines & Services	223.3	208.4	960.5	701.1
Petrochemical & Refined Products Services	411.3	315.0	1,019.1	785.0
Total segment gross operating margin	$ 2,080.4	$ 2,033.3	$ 6,428.5	$ 6,093.4

Summarized Segment Financial Information

Information by business segment, together with reconciliations to amounts presented on, or included in, our Unaudited Condensed Statements of Consolidated Operations, is presented in the following table:

	Reportable Business Segments					
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:						
Three months ended September 30, 2021	$ 3,814.5	$ 3,210.0	$ 975.7	$ 2,800.2	$ –	$ 10,800.4
Three months ended September 30, 2020	2,612.4	1,518.0	604.6	2,179.5	–	6,914.5
Nine months ended September 30, 2021	10,979.6	7,867.3	3,265.2	7,270.1	–	29,382.2
Nine months ended September 30, 2020	8,053.4	5,007.0	1,855.2	5,210.7	–	20,126.3
Revenues from related parties:						
Three months ended September 30, 2021	2.1	24.6	4.2	–	–	30.9
Three months ended September 30, 2020	1.6	3.6	2.3	–	–	7.5
Nine months ended September 30, 2021	7.6	36.3	10.6	–	–	54.5
Nine months ended September 30, 2020	5.0	16.7	7.5	–	–	29.2
Intersegment and intrasegment revenues:						
Three months ended September 30, 2021	13,753.5	6,611.2	145.9	6,149.9	(26,660.5)	–
Three months ended September 30, 2020	7,098.2	6,422.5	117.0	1,297.8	(14,935.5)	–
Nine months ended September 30, 2021	37,140.3	21,907.8	441.0	18,979.7	(78,468.8)	–
Nine months ended September 30, 2020	18,826.6	18,302.7	325.0	2,815.6	(40,269.9)	–
Total revenues:						
Three months ended September 30, 2021	17,570.1	9,845.8	1,125.8	8,950.1	(26,660.5)	10,831.3
Three months ended September 30, 2020	9,712.2	7,944.1	723.9	3,477.3	(14,935.5)	6,922.0
Nine months ended September 30, 2021	48,127.5	29,811.4	3,716.8	26,249.8	(78,468.8)	29,436.7
Nine months ended September 30, 2020	26,885.0	23,326.4	2,187.7	8,026.3	(40,269.9)	20,155.5
Equity in income (loss) of unconsolidated affiliates:						
Three months ended September 30, 2021	30.5	105.2	1.4	0.5	–	137.6
Three months ended September 30, 2020	29.3	51.8	1.4	(0.5)	–	82.0
Nine months ended September 30, 2021	87.5	354.2	4.3	1.2	–	447.2
Nine months ended September 30, 2020	90.8	243.2	4.3	(2.2)	–	336.1

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany transactions. Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base.

Information by business segment, together with reconciliations to our Unaudited Condensed Consolidated Balance Sheet totals, is presented in the following table:

	Reportable Business Segments					
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	Consolidated Total
Property, plant and equipment, net: (see Note 4)						
At September 30, 2021	$ 17,330.0	$ 6,927.3	$ 8,280.3	$ 7,533.6	$ 2,182.6	$ 42,253.8
At December 31, 2020	17,128.3	6,982.6	8,465.8	7,528.4	1,807.7	41,912.8
Investments in unconsolidated affiliates: (see Note 5)						
At September 30, 2021	656.4	1,742.1	32.1	2.8	–	2,433.4
At December 31, 2020	671.6	1,723.7	31.4	2.5	–	2,429.2
Intangible assets, net: (see Note 6)						
At September 30, 2021	323.2	1,879.4	859.1	128.3	–	3,190.0
At December 31, 2020	334.1	1,936.6	905.0	133.4	–	3,309.1
Goodwill: (see Note 6)						
At September 30, 2021	2,651.7	1,841.0	–	956.2	–	5,448.9
At December 31, 2020	2,651.7	1,841.0	–	956.2	–	5,448.9
Segment assets:						
At September 30, 2021	20,961.3	12,389.8	9,171.5	8,620.9	2,182.6	53,326.1
At December 31, 2020	20,785.7	12,483.9	9,402.2	8,620.5	1,807.7	53,100.0

Supplemental Revenue and Expense Information

The following table presents additional information regarding our consolidated revenues and costs and expenses for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Consolidated revenues:				
NGL Pipelines & Services	$ 3,816.6	$ 2,614.0	$ 10,987.2	$ 8,058.4
Crude Oil Pipelines & Services	3,234.6	1,521.6	7,903.6	5,023.7
Natural Gas Pipelines & Services	979.9	606.9	3,275.8	1,862.7
Petrochemical & Refined Products Services	2,800.2	2,179.5	7,270.1	5,210.7
Total consolidated revenues	$ 10,831.3	$ 6,922.0	$ 29,436.7	$ 20,155.5
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	$ 8,112.8	$ 4,313.7	$ 21,215.8	$ 12,331.9
Other operating costs and expenses (1)	757.3	696.9	2,174.2	2,120.4
Depreciation, amortization and accretion	511.3	484.2	1,516.9	1,461.3
Asset impairment charges	29.3	77.0	112.7	90.4
Net losses (gains) attributable to asset sales and related matters	(2.2)	(0.6)	9.0	(2.1)
General and administrative costs	47.3	50.3	155.1	162.8
Total consolidated costs and expenses	$ 9,455.8	$ 5,621.5	$ 25,183.7	$ 16,164.7

(1) Represents the cost of operating our plants, pipelines and other fixed assets excluding: depreciation, amortization and accretion charges; asset impairment charges; and net losses (or gains) attributable to asset sales and related matters.

Fluctuations in our product sales revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to product sales; however, these higher commodity prices would also be expected to increase the associated cost of sales as purchase costs are higher. The same type of relationship would be true in the case of lower energy commodity sales prices and purchase costs.

Note 11. Earnings Per Unit

The following table presents our calculation of basic and diluted earnings per common unit for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
BASIC EARNINGS PER COMMON UNIT				
Net income attributable to common unitholders	$ 1,153.0	$ 1,052.6	$ 3,605.7	$ 3,437.4
Earnings allocated to phantom unit awards (1)	(9.1)	(7.5)	(29.0)	(24.9)
Net income allocated to common unitholders	$ 1,143.9	$ 1,045.1	$ 3,576.7	$ 3,412.5
Basic weighted-average number of common units outstanding	2,184.0	2,185.5	2,184.2	2,186.7
Basic earnings per common unit	$ 0.52	$ 0.48	$ 1.64	$ 1.56
DILUTED EARNINGS PER COMMON UNIT				
Net income attributable to common unitholders	$ 1,153.0	$ 1,052.6	$ 3,605.7	$ 3,437.4
Net income attributable to preferred units	0.8	–*	2.7	–*
Net income attributable to limited partners	$ 1,153.8	$ 1,052.6	$ 3,608.4	$ 3,437.4
Diluted weighted-average number of units outstanding:				
Distribution-bearing common units	2,184.0	2,185.5	2,184.2	2,186.7
Phantom units (2)	17.5	15.9	17.6	15.7
Preferred units (2)	2.5	–*	2.5	–*
Total	2,204.0	2,201.4	2,204.3	2,202.4
Diluted earnings per common unit	$ 0.52	$ 0.48	$ 1.64	$ 1.56

* Amount is negligible

(1) Phantom units are considered participating securities for purposes of computing basic earnings per unit. See Note 12 for information regarding the phantom units.
(2) We use the "if-converted method" to determine the potential dilutive effect of the vesting of phantom unit awards and the conversion of preferred units outstanding. See Note 12 for information regarding phantom unit awards. See Note 8 for information regarding preferred units.

Note 12. Equity-Based Awards

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes compensation expense we recognized in connection with equity-based awards for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Equity-classified awards:				
Phantom unit awards	$ 35.0	$ 37.3	$ 111.0	$ 113.1
Profits interest awards	0.6	2.2	4.7	7.2
Liability-classified awards	–	–	0.1	–
Total	$ 35.6	$ 39.5	$ 115.8	$ 120.3

The fair value of equity-classified awards is amortized to earnings over the requisite service or vesting period. Equity-classified awards are expected to result in the issuance of the Partnership's common units upon vesting. Compensation expense for liability-classified awards is recognized over the requisite service or vesting period based on the fair value of the award remeasured at each reporting date. Liability-classified awards are settled in cash upon vesting.

Phantom Unit Awards

Subject to customary forfeiture provisions, phantom unit awards allow recipients to acquire the Partnership's common units once a defined vesting period expires (at no cost to the recipient apart from fulfilling required service and other conditions). The following table presents phantom unit award activity for the period indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Phantom unit awards at December 31, 2020	15,669,442	$ 26.76
Granted (2)	7,720,645	$ 21.30
Vested	(5,574,695)	$ 27.01
Forfeited	(514,907)	$ 24.48
Phantom unit awards at September 30, 2021	17,300,485	$ 24.31

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of phantom unit awards issued during 2021 was $164.4 million based on a grant date market price of the Partnership's common units ranging from $20.79 to $22.05 per unit. An estimated annual forfeiture rate of 2.0% was applied to these awards.

Each phantom unit award includes a DER, which entitles the participant to nonforfeitable cash payments equal to the product of the number of phantom unit awards outstanding for the participant and the cash distribution per common unit paid by the Partnership to its common unitholders. Cash payments made in connection with DERs are charged to partners' equity when the phantom unit award is expected to result in the issuance of common units; otherwise, such amounts are expensed.

The following table presents supplemental information regarding phantom unit awards for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Cash payments made in connection with DERs	$ 7.9	$ 7.1	$ 23.1	$ 20.0
Total intrinsic value of phantom unit awards that vested during period	3.5	2.0	122.6	113.4

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $185.1 million at September 30, 2021, of which our share of such cost is currently estimated to be $153.0 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.0 years.

Profits Interest Awards

In 2016 and 2018, EPCO Holdings Inc., a privately held affiliate of EPCO, contributed a portion of the Partnership common units it owned to form limited partnerships (referred to as "Employee Partnerships") that serve as long-term incentive arrangements for key employees of EPCO by providing them a "profits interest" (in the form of a Class B limited partner interest) in an Employee Partnership.

The Class B limited partner interests of two of the four Employee Partnerships outstanding at January 1, 2021, EPD PubCo Unit II L.P. and EPD PrivCo Unit I L.P., vested on June 11, 2021 when the closing market price of the Partnership's common units exceeded $25.41 per unit. As a result of these vesting events, we recognized an aggregate $1.9 million of non-cash, compensation expense in the three months ended June 30, 2021.

The Class B limited partner interests of EPD Unit IV L.P. and EPCO Unit II L.P. remain outstanding. At September 30, 2021, our share of the total unrecognized compensation cost related to these two Employee Partnerships was $10.4 million, which we expect to recognize over a weighted-average period of 2.2 years.

Note 13. Hedging Activities and Fair Value Measurements

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with assets, liabilities and certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward-starting swaps, options to enter into forward-starting swaps ("swaptions"), and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy may be used in controlling our overall cost of capital associated with such borrowings.

Forward-Starting Swaps
As a result of favorable market conditions, we terminated an aggregate $675.0 million notional amount of forward-starting swaps in March 2021, which resulted in a net cash payment of $0.1 million. Since the original swaptions associated with these forward-starting swaps were not designated as hedging instruments and were subject to mark-to-market accounting, we previously incurred an unrealized, mark-to-market loss at inception of the forward starting swaps of $47.6 million that was reflected as an increase in interest expense in 2019. Immediately following exercise of the swaptions and our being put into the forward-starting swaps, these instruments were designated as cash flow hedges. For the period from inception through the termination date in March 2021, we recognized cumulative gains on the forward-starting swaps of $47.5 million in accumulated other comprehensive income, of which $45.9 million will be reclassified to earnings (as a decrease in interest expense) over the life of the associated debt obligations. We reclassified $1.6 million of the cumulative gain as a decrease in interest expense in March 2021.

We terminated an additional aggregate $400.0 million notional amount of forward-starting swaps in March 2021 due to favorable market conditions, which resulted in net cash proceeds of $75.3 million. As cash flow hedges, gains on these derivative instruments are reflected as a component of accumulated other comprehensive income and will be reclassified to earnings (as a decrease in interest expense) over the life of the associated future debt obligations.

As a result of these terminations, we do not have any interest rate derivative instruments outstanding at September 30, 2021.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, petrochemicals and refined products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps and basis swaps.

At September 30, 2021, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging natural gas processing margins and (iii) hedging the fair value of commodity products held in inventory.

The following table summarizes our portfolio of commodity derivative instruments outstanding at September 30, 2021 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (billion cubic feet (“Bcf”))	18.8	2.6	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	0.6	0.1	Cash flow hedge
Octane enhancement:			
Forecasted sales of octane enhancement products (MMBbls)	23.0	2.8	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	2.4	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	126.5	4.7	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	142.4	2.7	Cash flow hedge
NGLs inventory management activities (MMBbls)	1.8	n/a	Fair value hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	10.5	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	10.7	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	4.1	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	5.9	0.1	Cash flow hedge
Petrochemical marketing:			
Forecasted purchases of petrochemical products (MMBbls)	0.5	n/a	Cash flow hedge
Forecasted sales of petrochemical products (MMBbls)	0.9	n/a	Cash flow hedge
Commercial energy:			
Forecasted purchases of power related to asset operations (terawatt hours (“TWh”))	0.7	0.2	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3)	5.3	0.2	Mark-to-market
NGL risk management activities (MMBbls) (3)	42.3	14.3	Mark-to-market
Refined products risk management activities (MMBbls) (3)	8.1	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (3)	28.6	2.4	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2023, January 2022 and December 2023, respectively.
(3) Reflects the use of derivative instruments to manage risks associated with our transportation, processing and storage assets.

The carrying amount of our inventories subject to fair value hedges was $151.5 million and $144.0 million at September 30, 2021 and December 31, 2020, respectively.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	September 30, 2021		December 31, 2020		September 30, 2021		December 31, 2020	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Current assets	$ –	Current assets	$ –	Current liabilities	$ –	Current liabilities	$ 109.1
Interest rate derivatives	Other assets	–	Other assets	12.4	Other liabilities	–	Other liabilities	11.0
Total interest rate derivatives		–		12.4		–		120.1
Commodity derivatives	Current assets	637.4	Current assets	210.5	Current liabilities	706.0	Current liabilities	234.0
Commodity derivatives	Other assets	8.4	Other assets	0.4	Other liabilities	12.3	Other liabilities	6.1
Total commodity derivatives		645.8		210.9		718.3		240.1
Total derivatives designated as hedging instruments		$ 645.8		$ 223.3		$ 718.3		$ 360.2
Derivatives not designated as hedging instruments								
Commodity derivatives	Current assets	$ 57.5	Current assets	$ 18.1	Current liabilities	$ 64.1	Current liabilities	$ 6.1
Commodity derivatives	Other assets	8.4	Other assets	0.2	Other liabilities	7.5	Other liabilities	0.1
Total commodity derivatives		65.9		18.3		71.6		6.2
Total derivatives not designated as hedging instruments		$ 65.9		$ 18.3		$ 71.6		$ 6.2

Certain of our commodity derivative instruments are subject to master netting arrangements or similar agreements. The following tables present our derivative instruments subject to such arrangements at the dates indicated:

	Offsetting of Financial Assets and Derivative Assets						
				Gross Amounts Not Offset in the Balance Sheet			
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Financial Instruments	Cash Collateral Received	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)			(v) = (iii) + (iv)
As of September 30, 2021:							
Commodity derivatives	$ 711.7	$ –	$ 711.7	$ (711.2)	$ –	$ –	$ 0.5
As of December 31, 2020:							
Interest rate derivatives	$ 12.4	$ –	$ 12.4	$ –	$ –	$ –	$ 12.4
Commodity derivatives	229.2	–	229.2	(228.5)	–	–	0.7

	Offsetting of Financial Liabilities and Derivative Liabilities						
				Gross Amounts Not Offset in the Balance Sheet			
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Financial Instruments	Cash Collateral Received	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)			(v) = (iii) + (iv)
As of September 30, 2021:							
Commodity derivatives	$ 789.9	$ –	$ 789.9	$ (711.2)	$ –	$ (77.7)	$ 1.0
As of December 31, 2020:							
Interest rate derivatives	$ 120.1	$ –	$ 120.1	$ –	$ –	$ –	$ 120.1
Commodity derivatives	246.3	–	246.3	(228.5)	–	(17.3)	0.5

Derivative assets and liabilities recorded on our Unaudited Condensed Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. The tabular presentation above provides a means for comparing the gross amount of derivative assets and liabilities, excluding associated accounts payable and receivable, to the net amount that would likely be receivable or payable under a default scenario based on the existence of rights of offset in the respective derivative agreements. Any cash collateral paid or received is reflected in these tables, but only to the extent that it represents variation margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from these tables.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2021	2020	2021	2020
Commodity derivatives	Revenue	$ (49.5)	$ (19.8)	$ (236.6)	$ (69.1)
Total		$ (49.5)	$ (19.8)	$ (236.6)	$ (69.1)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2021	2020	2021	2020
Commodity derivatives	Revenue	$ 21.5	$ 22.4	$ 230.0	$ 142.6
Total		$ 21.5	$ 22.4	$ 230.0	$ 142.6

The gain (loss) corresponding to the hedge ineffectiveness on the fair value hedges was negligible for all periods presented. The remaining gain (loss) for each period presented is primarily attributable to prompt-to-forward month price differentials that were excluded from the assessment of hedge effectiveness.

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Operations and Unaudited Condensed Statements of Consolidated Comprehensive Income for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) on Derivative			
	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Interest rate derivatives	$ –	$ 62.6	$ 182.9	$ (207.7)
Commodity derivatives – Revenue (1)	(110.8)	2.6	(843.5)	404.5
Commodity derivatives – Operating costs and expenses (1)	10.2	(6.8)	(8.7)	(11.8)
Total	$ (100.6)	$ 58.4	$ (669.3)	$ 185.0

(1) The fair value of these derivative instruments will be reclassified to their respective locations on the Unaudited Condensed Statement of Consolidated Operations when the forecasted transactions affect earnings.

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2021	2020	2021	2020
Interest rate derivatives	Interest expense	$ (10.3)	$ (9.9)	$ (29.1)	$ (29.2)
Commodity derivatives	Revenue	(116.8)	(19.5)	(614.9)	344.7
Commodity derivatives	Operating costs and expenses	(0.3)	(10.0)	(18.9)	(9.9)
Total		$ (127.4)	$ (39.4)	$ (662.9)	$ 305.6

Over the next twelve months, we expect to reclassify $28.2 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $283.6 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, with $294.3 million as a decrease in revenue and $10.7 million as a decrease in operating costs and expenses.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2021	2020	2021	2020
Commodity derivatives	Revenue	$ 107.2	$ 14.7	$ 143.6	$ 113.4
Commodity derivatives	Operating costs and expenses	1.5	0.1	1.5	0.9
Total		$ 108.7	$ 14.8	$ 145.1	$ 114.3

The $145.1 million gain recognized for the nine months ended September 30, 2021 (as noted in the preceding table) from derivatives not designated as hedging instruments consists of $7.3 million of realized gains and $137.8 million of net unrealized mark-to-market gains attributable to commodity derivatives.

Fair Value Measurements

The following tables set forth, by level within the Level 1, 2 and 3 fair value hierarchy, the carrying values of our financial assets and liabilities at the dates indicated. These assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input used to estimate their fair value. Our assessment of the relative significance of such inputs requires judgment.

The values for commodity derivatives are presented before and after the application of Chicago Mercantile Exchange (“CME”) Rule 814, which deems that financial instruments cleared by the CME are settled daily in connection with variation margin payments. As a result of this exchange rule, CME-related derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes; however, the derivatives remain outstanding and subject to future commodity price fluctuations until they are settled in accordance with their contractual terms. Derivative transactions cleared on exchanges other than the CME (e.g., the Intercontinental Exchange or ICE) continue to be reported on a gross basis.

	At September 30, 2021 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Commodity derivatives:				
Value before application of CME Rule 814	$ 435.3	$ 2,344.1	$ 0.1	$ 2,779.5
Impact of CME Rule 814	(435.3)	(1,632.5)	–	(2,067.8)
Total commodity derivatives	–	711.6	0.1	711.7
Total	$ –	$ 711.6	$ 0.1	$ 711.7
Financial liabilities:				
Commodity derivatives:				
Value before application of CME Rule 814	$ 655.1	$ 2,594.5	$ 0.2	$ 3,249.8
Impact of CME Rule 814	(655.1)	(1,804.8)	–	(2,459.9)
Total commodity derivatives	–	789.7	0.2	789.9
Total	$ –	$ 789.7	$ 0.2	$ 789.9

	At December 31, 2020 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Interest rate derivatives	$ –	$ 12.4	$ –	$ 12.4
Commodity derivatives:				
Value before application of CME Rule 814	678.6	878.6	12.9	1,570.1
Impact of CME Rule 814	(678.6)	(650.4)	(11.9)	(1,340.9)
Total commodity derivatives	–	228.2	1.0	229.2
Total	$ –	$ 240.6	$ 1.0	$ 241.6
Financial liabilities:				
Interest rate derivatives	$ –	$ 120.1	$ –	$ 120.1
Commodity derivatives:				
Value before application of CME Rule 814	1,065.6	1,047.4	25.9	2,138.9
Impact of CME Rule 814	(1,065.6)	(807.3)	(19.7)	(1,892.6)
Total commodity derivatives	–	240.1	6.2	246.3
Total	$ –	$ 360.2	$ 6.2	$ 366.4

In the aggregate, the fair value of our commodity hedging portfolios at September 30, 2021 was a net derivative liability of $470.3 million prior to the impact of CME Rule 814.

Financial assets and liabilities recorded on the balance sheet at September 30, 2021 using significant unobservable inputs (Level 3) are not material to the Unaudited Condensed Consolidated Financial Statements.

Nonrecurring Fair Value Measurements

We did not have any significant nonrecurring fair value measurements during the nine months ended September 30, 2021 or 2020.

See Note 4 for information regarding other non-cash asset impairment charges.

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash balances), accounts receivable, commercial paper notes and accounts payable approximate their fair values based on their short-term nature. The estimated total fair value of our fixed-rate debt obligations was $33.9 billion and $35.0 billion at September 30, 2021 and December 31, 2020, respectively. The aggregate carrying value of these debt obligations was $29.58 billion and $29.9 billion at September 30, 2021 and December 31, 2020, respectively. These values are primarily based on quoted market prices for such debt or debt of similar terms and maturities (Level 2) and our credit standing. Changes in market rates of interest affect the fair value of our fixed-rate debt. The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

Note 14. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Revenues – related parties:				
Unconsolidated affiliates	$ 30.9	$ 7.5	$ 54.5	$ 29.2
Costs and expenses – related parties:				
EPCO and its privately held affiliates	$ 287.1	$ 283.9	$ 861.8	$ 847.0
Unconsolidated affiliates	84.2	33.1	201.4	167.2
Total	$ 371.3	$ 317.0	$ 1,063.2	$ 1,014.2

The following table summarizes our related party accounts receivable and accounts payable balances at the dates indicated:

	September 30, 2021	December 31, 2020
Accounts receivable - related parties:		
EPCO and its privately held affiliates	$ 1.3	$ 1.9
Unconsolidated affiliates	1.7	3.7
Total	$ 3.0	$ 5.6
Accounts payable - related parties:		
EPCO and its privately held affiliates	$ 110.1	$ 139.6
Unconsolidated affiliates	14.6	9.9
Total	$ 124.7	$ 149.5

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its privately held affiliates (including Enterprise GP, our general partner), which are not a part of our consolidated group of companies.

At September 30, 2021, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts) beneficially owned the following limited partner interests in us:

Total Number of Limited Partner Interests Held	Percentage of Common Units Outstanding
702,152,448 common units	32.2%

Of the total number of Partnership common units held by EPCO and its privately held affiliates, 92,976,464 have been pledged as security under the separate credit facilities of EPCO and its privately held affiliates at September 30, 2021. These credit facilities contain customary and other events of default, including defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of these units and affect the market price of the Partnership's common units.

The Partnership and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are also separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other activities and to meet their respective debt obligations. During the nine months ended September 30, 2021 and 2020, we paid EPCO and its privately held affiliates cash distributions totaling $918.1 million and $908.2 million, respectively.

We have no employees. All of our administrative and operating functions are provided either by employees of EPCO (pursuant to the ASA) or by other service providers. We and our general partner are parties to the ASA. The following table presents our related party costs and expenses attributable to the ASA with EPCO for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Operating costs and expenses	$ 253.7	$ 247.8	$ 755.5	$ 740.9
General and administrative expenses	33.4	32.1	98.0	94.6
Total costs and expenses	$ 287.1	$ 279.9	$ 853.5	$ 835.5

We lease office space from privately held affiliates of EPCO at rental rates that approximate market rates. For the three months ended September 30, 2021 and 2020, we recognized $3.4 million and $3.3 million, respectively, of related party operating lease expense in connection with these office space leases. For the nine months ended September 30, 2021 and 2020, we recognized $10.1 million and $9.6 million, respectively, of related party operating lease expense in connection with these office space leases.

Note 15. Income Taxes

The following table presents the components of our consolidated benefit from (provision for) income taxes for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Deferred tax benefit (expense) attributable to OTA Holdings, Inc. ("OTA")	$ (6.8)	$ 21.3	$ (20.1)	$ 158.0
Revised Texas Franchise Tax ("Texas Margin Tax")	(9.6)	(7.2)	(37.0)	(21.9)
Other	0.3	5.0	(0.2)	2.5
Benefit from (provision for) income taxes	$ (16.1)	$ 19.1	$ (57.3)	$ 138.6

Our federal, state and foreign income tax benefit (provision) is summarized below:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Current portion of income tax benefit (provision):				
Federal	$ 1.0	$ 5.3	$ 1.6	$ 3.0
State	(8.2)	(4.7)	(24.8)	(13.4)
Foreign	0.1	0.2	(1.0)	–
Total current portion	(7.1)	0.8	(24.2)	(10.4)
Deferred portion of income tax benefit (provision):				
Federal	(7.1)	18.7	(19.3)	145.1
State	(1.9)	(0.4)	(13.8)	3.9
Foreign	–	–	–	–
Total deferred portion	(9.0)	18.3	(33.1)	149.0
Total benefit from (provision for) income taxes	$ (16.1)	$ 19.1	$ (57.3)	$ 138.6

A reconciliation of the benefit from (provision for) income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Pre-Tax Net Book Income (“NBI”)	$ 1,198.2	$ 1,064.9	$ 3,748.0	$ 3,381.2
Texas Margin Tax (1)	(9.6)	(7.2)	(37.0)	(21.9)
State income tax benefit (provision), net of federal benefit (2)	(0.1)	1.6	(1.0)	9.7
Federal income tax benefit (provision) computed by applying the federal statutory rate to NBI of corporate entities	(3.3)	25.1	(9.8)	83.4
Federal benefit attributable to settlement of Liquidity Option Agreement (2)	–	–	–	67.8
Valuation allowance (3)	(3.1)	–	(9.3)	–
Other	–	(0.4)	(0.2)	(0.4)
Benefit from (provision for) income taxes	$ (16.1)	$ 19.1	$ (57.3)	$ 138.6
Effective income tax rate	(1.3)%	1.8%	(1.5)%	4.1%

(1) Although the Texas Margin Tax is not considered a state income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers our Texas-sourced revenues and expenses.
(2) The total benefit recognized in income tax expense on March 5, 2020 from settlement of the Liquidity Option was $72.2 million, which is comprised of $4.4 million of state income tax benefit and $67.8 million of federal income tax benefit.
(3) Management believes that it is more likely than not that the net deferred tax assets attributable to OTA will not be fully realizable; therefore, we have provided for a valuation allowance.

The following table presents the significant components of deferred tax assets and deferred tax liabilities at the dates indicated:

	September 30, 2021	December 31, 2020
Deferred tax liabilities:		
Attributable to investment in OTA	$ 376.7	$ 356.6
Attributable to property, plant and equipment	119.8	106.4
Attributable to investments in other entities	4.4	4.1
Other	13.5	–
Total deferred tax liabilities	514.4	467.1
Deferred tax assets:		
Net operating loss carryovers (1)	9.4	0.1
Temporary differences related to Texas Margin Tax	3.0	2.3
Total deferred tax assets	12.4	2.4
Valuation allowance	9.3	–
Total deferred tax assets, net of valuation allowance	3.1	2.4
Total net deferred tax liabilities	$ 511.3	$ 464.7

(1) Of the loss amount presented for September 30, 2021, $0.1 million expires in various years between 2021 and 2037. The remaining $9.3 million has an indefinite carryover period. All losses are subject to limitations on their utilization.

OTA Deferred Tax Liability

On March 5, 2020, the Partnership settled its obligations under a put option agreement (the "Liquidity Option Agreement" or "Liquidity Option") with OTA and Marquard & Bahls AG, and became the owner of OTA and indirectly assumed its deferred tax liability, which reflects OTA's outside basis difference in the limited partner interests it received from the Partnership in October 2014. Upon settlement of the Liquidity Option, the Liquidity Option liability recorded by the Partnership was effectively replaced by the deferred tax liability of OTA calculated in accordance with ASC 740, *Income Taxes*.

At March 5, 2020, the Liquidity Option liability amount was $511.9 million. Since the book value of the Liquidity Option liability exceeded OTA's estimated deferred tax liability of $439.7 million on that date, we recognized a non-cash benefit in earnings of $72.2 million, which is reflected in the "Benefit from (provision for) income taxes" line on our Unaudited Condensed Statement of Consolidated Operations for the nine months ended September 30, 2020. OTA recognized an additional net, non-cash deferred income tax benefit of $85.8 million at September 30, 2020 primarily due to a decrease in the outside basis difference of its investment in the Partnership attributable to a decline in the market price of the Partnership's common units subsequent to March 5, 2020 through September 30, 2020. In total, our earnings for the nine months ended September 30, 2020 reflect $158.0 million of net deferred income tax benefit attributable to OTA.

Note 16. Commitments and Contingent Liabilities

Litigation

As part of our normal business activities, we may be named as defendants in legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully indemnify us against losses arising from future legal proceedings. We will vigorously defend the Partnership in litigation matters.

Our accruals for litigation contingencies were $0.2 million and $6.1 million at September 30, 2021 and December 31, 2020, respectively. We have classified our accruals for litigation contingencies in our Unaudited Condensed Consolidated Balance Sheets as a component of "Other current liabilities" or "Other long-term liabilities" based on management's estimate regarding the timing of settlement.

PDH 1 Litigation

In July 2013, we executed a contract with Foster Wheeler USA Corporation ("Foster Wheeler") pursuant to which Foster Wheeler was to serve as the general contractor responsible for the engineering, procurement, construction and installation of our first propane dehydrogenation facility ("PDH 1"). In November 2014, Foster Wheeler was acquired by an affiliate of AMEC plc to form Amec Foster Wheeler plc, and Foster Wheeler is now known as Amec Foster Wheeler USA Corporation ("AFW"). In December 2015, Enterprise and AFW entered into a transition services agreement under which AFW was partially terminated from the PDH 1 project. In December 2015, Enterprise engaged a second contractor, Optimized Process Designs LLC, to complete the construction and installation of PDH 1.

On September 2, 2016, we terminated AFW for cause and filed a lawsuit in the 151st Judicial Civil District Court of Harris County, Texas against AFW and its parent company, Amec Foster Wheeler plc, asserting claims for breach of contract, breach of warranty, fraudulent inducement, string-along fraud, gross negligence, professional negligence, negligent misrepresentation and attorneys' fees. We intend to diligently prosecute these claims and seek all direct, consequential, and exemplary damages to which we may be entitled.

Contractual Obligations

Scheduled Maturities of Debt

We have long-term and short-term payment obligations under debt agreements. In total, the principal amount of our consolidated debt obligations were $29.82 billion and $30.15 billion at September 30, 2021 and December 31, 2020, respectively. The year-to-date reduction in debt principal amount outstanding is due to EPO's repayment of Senior Notes TT and RR, partially offset by EPO's issuance of Senior Notes EEE. See Note 7 for additional information regarding our scheduled future maturities of debt principal.

Lease Accounting Matters

There has been no significant change in our operating lease obligations since those disclosed in the 2020 Form 10-K.

The following table presents information regarding operating leases where we are the lessee at September 30, 2021:

Asset Category	ROU Asset Carrying Value (1)	Lease Liability Carrying Value (2)	Weighted-Average Remaining Term	Weighted-Average Discount Rate (3)
Storage and pipeline facilities	$ 164.0	$ 164.5	12 years	3.6%
Transportation equipment	22.6	24.4	2 years	2.6%
Office and warehouse space	166.3	190.2	15 years	3.2%
Total	$ 352.9	$ 379.1		

(1) Right-of-use ("ROU") asset amounts are a component of "Other assets" on our Unaudited Condensed Consolidated Balance Sheet.
(2) At September 30, 2021, lease liabilities of $35.5 million and $343.6 million were included within "Other current liabilities" and "Other long-term liabilities," respectively.
(3) The discount rate for each category of assets represents the weighted average of either (i) the implicit rate applicable to the underlying leases (where determinable) or (ii) our incremental borrowing rate adjusted for collateralization (if the implicit rate is not determinable). In general, the discount rates are based on either information available at the lease commencement date or January 1, 2019 for leases existing at the adoption date for ASC 842, *Leases*.

The following table disaggregates our total operating lease expense for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Long-term operating leases:				
Fixed lease expense:				
Non-cash lease expense (amortization of ROU assets)	$ 10.9	$ 9.8	$ 29.5	$ 29.6
Related accretion expense on lease liability balances	3.2	3.1	9.3	9.8
Total fixed lease expense	14.1	12.9	38.8	39.4
Variable lease expense	0.2	0.1	0.8	0.4
Subtotal operating lease expense	14.3	13.0	39.6	39.8
Short-term operating leases	15.0	12.3	41.4	37.3
Total operating lease expense	$ 29.3	$ 25.3	$ 81.0	$ 77.1

Cash payments attributable to operating lease liabilities were $10.8 million and $9.8 million for the three months ended September 30, 2021 and 2020, respectively. For the nine months ended September 30, 2021 and 2020, cash paid for operating lease liabilities was $29.2 million and $28.1 million, respectively.

Operating lease income for the three months ended September 30, 2021 and 2020 was $3.1 million and $2.3 million, respectively. For the nine months ended September 30, 2021 and 2020, operating lease income was $9.2 and $8.4 million, respectively.

Purchase Obligations

We have contractual future product purchase commitments for natural gas, NGLs, crude oil, petrochemicals and refined products representing enforceable and legally binding agreements as of the reporting date. Our product purchase commitments increased from $14.8 billion at December 31, 2020 to $22.1 billion at September 30, 2021 primarily due to an increase in crude oil and NGL prices between the two reporting dates.

Note 17. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating accounts and cash payments for interest and income taxes for the periods indicated:

	For the Nine Months Ended September 30,	
	2021	2020
Decrease (increase) in:		
Accounts receivable – trade	$ (1,541.0)	$ 1,119.5
Accounts receivable – related parties	2.0	1.0
Inventories	520.2	(1,063.2)
Prepaid and other current assets	409.7	288.2
Other assets	104.0	(27.7)
Increase (decrease) in:		
Accounts payable – trade	35.6	147.0
Accounts payable – related parties	(24.8)	(41.0)
Accrued product payables	2,501.8	(621.9)
Accrued interest	(230.4)	(196.6)
Other current liabilities	(696.3)	(212.3)
Other liabilities	(33.7)	(85.0)
Net effect of changes in operating accounts	$ 1,047.1	$ (692.0)
Cash payments for interest, net of $63.8 and $96.9 capitalized during the nine months ended September 30, 2021 and 2020, respectively	$ 1,143.5	$ 1,107.4
Cash payments for federal and state income taxes	$ 17.0	$ 24.9

We incurred liabilities for construction in progress that had not been paid at September 30, 2021 and December 31, 2020 of $194.6 million and $236.1 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Unaudited Condensed Statements of Consolidated Cash Flows.

We recognized non-cash charges totaling $11.3 million for involuntary conversions during the nine months ended September 30, 2021 that are a component of net losses attributable to asset sales and related matters.

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

For the Three and Nine Months Ended September 30, 2021 and 2020

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and accompanying Notes included in this quarterly report on Form 10-Q and the Audited Consolidated Financial Statements and related Notes, together with our discussion and analysis of financial position and results of operations, included in our annual report on Form 10-K for the year ended December 31, 2020 (the "2020 Form 10-K"), as filed on March 1, 2021 with the U.S. Securities and Exchange Commission ("SEC"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States ("U.S.").

Cautionary Statement Regarding Forward-Looking Information

This quarterly report on Form 10-Q for the nine months ended September 30, 2021 (our "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 us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "would," "will," "believe," "may," "scheduled," "potential" 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 our expectations reflected in such forward-looking statements (including any forward-looking statements/expectations of third parties referenced in this quarterly report) are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct.

Forward-looking statements are subject to a variety of risks (including those attributable to the Coronavirus disease 2019 ("COVID-19") pandemic), uncertainties and assumptions as described in more detail under Part I, Item 1A of our 2020 Form 10-K. 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. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this quarterly report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Key References Used in this Management's Discussion and Analysis

Unless the context requires otherwise, references to "we," "us" or "our" within this quarterly report are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to the "Partnership" mean Enterprise Products Partners L.P. on a standalone basis.

References to "EPO" mean Enterprise Products Operating LLC, which is an indirect wholly owned subsidiary of the Partnership, and its consolidated subsidiaries, through which the Partnership conducts its business. We are managed by our general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a privately held Texas limited liability company.

The membership interests of Dan Duncan LLC are owned by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director and Chairman of the Board of Directors (the "Board") of Enterprise GP; (ii) Richard H. Bachmann, who is also a director and Vice Chairman of the Board of Enterprise GP; and (iii) W. Randall Fowler, who is also a director and the Co-Chief Executive Officer and Chief Financial Officer of Enterprise GP. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company, a privately held Texas corporation, and its privately held affiliates. The outstanding voting capital stock of EPCO is owned by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Duncan Williams, who serves as Chairman of EPCO; (ii) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO; and (iii) Mr. Fowler, who serves as an Executive Vice President and the Chief Financial Officer of EPCO. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as directors of EPCO.

We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. EPCO, together with its privately held affiliates, owned approximately 32.2% of the Partnership's common units outstanding at September 30, 2021. In March 2021, a privately held affiliate of EPCO sold its entire ownership interest in the Partnership's Series A Cumulative Convertible Preferred Units ("preferred units") to third parties.

As generally used in the energy industry and in this quarterly report, the acronyms below have the following meanings:

/d	=	per day	MMBPD	=	million barrels per day
BBtus	=	billion British thermal units	MMBtus	=	million British thermal units
Bcf	=	billion cubic feet	MMcf	=	million cubic feet
BPD	=	barrels per day	MWac	=	megawatts, alternating current
MBPD	=	thousand barrels per day	MWdc	=	megawatts, direct current
MMBbls	=	million barrels	TBtus	=	trillion British thermal units

As used in this quarterly report, the phrase "quarter-to-quarter" means the third quarter of 2021 compared to the third quarter of 2020. Likewise, the phrase "period-to-period" means the nine months ended September 30, 2021 compared to the nine months ended September 30, 2020.

Business Summary

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Our preferred units are not publicly traded. We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products. We are owned by our limited partners (preferred and common unitholders) from an economic perspective. Enterprise GP, which owns a non-economic general partner interest in us, manages our Partnership. We conduct substantially all of our business operations through EPO and its consolidated subsidiaries.

Our fully integrated, midstream energy asset network (or "value chain") links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and the Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include:

- natural gas gathering, treating, processing, transportation and storage;

- NGL transportation, fractionation, storage, and marine terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane);

- crude oil gathering, transportation, storage, and marine terminals;

- propylene production facilities (including propane dehydrogenation ("PDH") facilities), butane isomerization, octane enhancement, isobutane dehydrogenation ("iBDH") and high purity isobutylene ("HPIB") production facilities;

- petrochemical and refined products transportation, storage, and marine terminals (including those used to export ethylene and polymer grade propylene ("PGP")); and

- a marine transportation business that operates on key U.S. inland and intracoastal waterway systems.

The safe operation of our assets is a top priority. We are committed to protecting the environment and the health and safety of the public and those working on our behalf by conducting our business activities in a safe and environmentally responsible manner. For additional information, see "*Environmental, Safety and Conservation*" within the Regulatory Matters section of Part I, Items 1 and 2 of the 2020 Form 10-K.

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers.

Our financial position, results of operations and cash flows are subject to certain risks. For information regarding such risks, see "*Risk Factors*" included under Part I, Item 1A of the 2020 Form 10-K.

We provide investors access to additional information regarding the Partnership and our consolidated businesses, including information relating to governance procedures and principles, through our website, *www.enterpriseproducts.com*.

Current Outlook

As noted previously under "Cautionary Statement Regarding Forward-Looking Information" within this Part I, Item 2, this quarterly report on Form 10-Q, including this update to our outlook on business conditions, contains forward-looking statements that are based on our beliefs and those of Enterprise GP. In addition, it reflects assumptions made by us and information currently available to us, which includes forecast information published by third parties. All references to U.S. Energy Information Administration ("EIA") forecasts and expectations are derived from its October 2021 Short-Term Energy Outlook ("October 2021 STEO"), which was published on October 13, 2021. The forecasts and other forward-looking information cited in the following discussion remain subject to uncertainty since global mitigation efforts and medical developments related to COVID-19 continue to evolve.

The outlook on business conditions in our 2020 Form 10-K addressed observations that production cuts within the Organization of the Petroleum Exporting Countries ("OPEC") and Russia (collectively, the "OPEC+" group), along with market-driven cuts in U.S., Brazilian and Canadian supplies, were providing much-needed support for international energy markets coping with the ongoing weakness in hydrocarbon demand attributable to the COVID-19 pandemic. We also discussed downstream demand beginning to recover from the lows of 2020, but remaining depressed due to the continued effects of the pandemic.

Throughout the first half of 2021, we highlighted the positive impact that the widespread implementation of vaccination programs and the related easing of COVID-19 mobility restrictions have had on global hydrocarbon demand and stated our belief that energy fundamentals (and global economic conditions in general) remained highly dependent on the successful containment of COVID-19, especially its more contagious emerging variants (e.g., the "Delta" variant), through the distribution, acceptance and administration of proven vaccines and therapeutics for the disease.

While we maintain our view that the successful containment of COVID-19 is crucial to sustained improvements in energy markets, we believe that production cuts are no longer necessary to support international energy markets and that global downstream demand, while stronger, has not fully recovered.

The global economy, including the U.S., experienced robust growth during 2021, mainly due to restocking inventories and efforts to satisfy consumer demand suppressed by the pandemic. According to the EIA, U.S. gross domestic product ("GDP") is forecast to increase 5.7% in 2021 and 4.5% in 2022, following a decline of 3.4% in 2020. During this time, we have observed a steady transition from near record levels of crude oil inventories in the U.S. to a more normalized level today as U.S. consumption has outpaced U.S. supply. We are now seeing temporary shortfalls in global natural gas and coal supplies as reports from some countries, particularly in Europe and Asia, have revealed a rationing of energy supplies and curtailments of industrial production. Some reports have referred to the current situation as an "energy crisis," which could become even more severe if the world experiences a colder than normal winter. We believe that U.S. supply and demand have become more balanced, but anticipate a slight supply shortfall going into 2022. The EIA estimates that U.S. production of petroleum and related liquids will average 18.6 MMBPD in 2021 and 20.0 MMBPD in 2022, while U.S. demand for petroleum and related liquids will average 19.7 MMBPD in 2021 and 20.4 MMBPD in 2022.

Throughout this period, prices have increased considerably as evidenced by the price of West Texas Intermediate ("WTI") crude oil at Cushing, Oklahoma (as reported by the New York Mercantile Exchange, or "NYMEX"). It reached six-year highs in October 2021 and averaged $71.54 per barrel in September 2021 compared to $52.10 per barrel in January 2021 and an average of $39.34 per barrel in 2020. The price of natural gas at Henry Hub, Louisiana (as reported by NYMEX) reached twelve-year highs in October 2021 and averaged $5.11 per MMBtu in September 2021 compared to $2.65 per MMBtu in January 2021 and an average of $2.13 per MMBtu in 2020.

Significant uncertainty exists with respect to the capabilities and willingness of OPEC+ to increase production enough to alleviate high crude oil prices and whether hydrocarbon demand will remain resilient as prices continue to rise. Despite ongoing pressures faced by many producers in the U.S. to preserve cash, return capital to their investors and reduce crude oil and natural gas production activities altogether, potential cash flows from these high price levels may eventually become too attractive for U.S. energy investors to forego. The EIA forecasts U.S. crude oil production will increase from an average of 11.0 MMBPD in 2021 to 11.7 MMBPD in 2022; however, these levels still lag behind the record level of 12.3 MMBPD in 2019. As U.S. production rises, we believe that our integrated, diversified and fee-based business will have additional opportunities to provide midstream services to our producers and customers.

Recent Developments

Enterprise and Chevron Explore Carbon Storage Business Opportunities

In September 2021, we and Chevron U.S.A. Inc. ("Chevron") jointly announced a framework to study and evaluate opportunities for carbon dioxide capture, utilization and storage from our respective business operations in the U.S. Midcontinent and Gulf Coast. Projects resulting from this evaluation would seek to combine our extensive midstream pipeline and storage network with Chevron's sub-surface expertise to create opportunities to capture, aggregate, transport and sequester carbon dioxide in support of the evolving energy landscape. The initial phase of the study in which we will evaluate specific business opportunities is expected to last about six months.

Issuance of $1.0 Billion of Senior Notes in September 2021

In September 2021, EPO issued $1.0 billion principal amount of senior notes due February 2053 ("Senior Notes EEE").   Net proceeds from this offering will be used for general company purposes, including for growth capital investments, and the repayment of debt (including the repayment of a portion of our $750.0 million in principal amount of 3.50% Senior Notes VV and/or a portion of our $650.0 million in principal amount of 4.05% Senior Notes CC, in each case at their maturity in February 2022).

Senior Notes EEE were issued at 99.170% of their principal amount and have a fixed rate of interest of 3.30% per year. The Partnership guaranteed these senior notes through an unconditional guarantee on an unsecured and unsubordinated basis.

Enterprise and Magellan Team Up With Intercontinental Exchange for New Houston Crude Oil Futures Contract

In June 2021, we, Magellan Midstream Partners, L.P ("Magellan") and Intercontinental Exchange, Inc. ("ICE") announced the establishment of a new futures contract for the physical delivery of crude oil in the Houston, Texas area in response to market interest for a Houston-based index with greater scale, flow assurance and price transparency. It will utilize the capabilities and global reach of ICE's industry-recognized, state-of-the-art trading platform and is due to be launched by ICE by early 2022, subject to regulatory approval.

The quality specifications of the new futures contract will be consistent with WTI originating from the Permian Basin with common delivery options at either our ECHO terminal in Houston or Magellan's East Houston terminal. In support of this new futures contract, we and Magellan expect to discontinue provisions for delivery services under legacy futures contracts that are deliverable at each terminal once the new futures contract is finalized and receives regulatory approval.

Enterprise to Increase Its Use of Power from Renewable Resources

In March 2021, we announced the execution of a power purchase agreement with EDF Renewables North America that will increase our use of electricity from solar power by 100 MWac/132 MWdc. We are committed to being a responsible steward of the environment, including using energy sustainably across our footprint. We estimate that by 2025, approximately 25% of our power will be from renewable resources.

Selected Energy Commodity Price Data

The following table presents selected average index prices for natural gas and selected NGL and petrochemical products for the periods indicated:

	Natural Gas, $/MMBtu	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound	Indicative Gas Processing Gross Spread $/gallon
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(4)
2020 by quarter:									
1st Quarter	$1.95	$0.14	$0.37	$0.57	$0.63	$0.93	$0.31	$0.18	$0.19
2nd Quarter	$1.71	$0.19	$0.41	$0.43	$0.44	$0.41	$0.26	$0.11	$0.17
3rd Quarter	$1.98	$0.22	$0.50	$0.58	$0.60	$0.80	$0.35	$0.17	$0.25
4th Quarter	$2.67	$0.21	$0.57	$0.76	$0.68	$0.92	$0.41	$0.24	$0.22
2020 Averages	$2.08	$0.19	$0.46	$0.59	$0.59	$0.77	$0.33	$0.18	$0.21
2021 by quarter:									
1st Quarter	$2.71	$0.24	$0.89	$0.94	$0.93	$1.33	$0.73	$0.44	$0.38
2nd Quarter	$2.83	$0.26	$0.87	$0.97	$0.98	$1.46	$0.67	$0.27	$0.41
3rd Quarter	$4.02	$0.35	$1.16	$1.34	$1.34	$1.62	$0.82	$0.36	$0.51
2021 Averages	$3.19	$0.28	$0.98	$1.09	$1.08	$1.47	$0.74	$0.36	$0.43

(1) Natural gas prices are based on Henry-Hub Inside FERC commercial index prices as reported by Platts, which is a division of S&P Global, Inc.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service ("OPIS") by IHS Markit ("IHS").
(3) Polymer grade propylene prices represent average contract pricing for such product as reported by IHS. Refinery grade propylene ("RGP") prices represent weighted-average spot prices for such product as reported by IHS.
(4) The "Indicative Gas Processing Gross Spread" represents our generic estimate of the gross economic benefit from extracting NGLs from natural gas production based on certain pricing assumptions. Specifically, it is the amount by which the assumed economic value of a composite gallon of NGLs at Mont Belvieu, Texas exceeds the value of the equivalent amount of energy in natural gas at Henry Hub, Louisiana. Our estimate of the indicative spread does not consider the operating costs incurred by a natural gas processing facility to extract the NGLs nor the transportation and fractionation costs to deliver the NGLs to market. In addition, the actual gas processing spread earned at each plant is further influenced by regional pricing and extraction dynamics.

The weighted-average indicative market price for NGLs was $0.84 per gallon in the third quarter of 2021 versus $0.41 per gallon in the third quarter of 2020. Likewise, the weighted-average indicative market price for NGLs was $0.70 per gallon during the nine months ended September 30, 2021 compared to $0.36 per gallon during the same period in 2020.

The following table presents selected average index prices for crude oil for the periods indicated:

	WTI Crude Oil, $/barrel	Midland Crude Oil, $/barrel	Houston Crude Oil $/barrel	LLS Crude Oil, $/barrel
	(1)	(2)	(2)	(3)
2020 by quarter:				
1st Quarter	$46.17	$45.51	$47.81	$48.15
2nd Quarter	$27.85	$28.22	$29.68	$30.12
3rd Quarter	$40.93	$41.05	$41.77	$42.47
4th Quarter	$42.66	$43.07	$43.63	$44.08
2020 Averages	$39.40	$39.46	$40.72	$41.21
2021 by quarter:				
1st Quarter	$57.84	$59.00	$59.51	$59.99
2nd Quarter	$66.07	$66.41	$66.90	$67.95
3rd Quarter	$70.56	$70.74	$71.17	$71.51
2021 Averages	$64.82	$65.38	$65.86	$66.48

(1) WTI prices are based on commercial index prices at Cushing, Oklahoma as measured by the NYMEX.
(2) Midland and Houston crude oil prices are based on commercial index prices as reported by Argus.
(3) Light Louisiana Sweet ("LLS") prices are based on commercial index prices as reported by Platts.

Fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. An increase in our consolidated marketing revenues due to higher energy commodity sales prices may not result in an increase in gross operating margin or cash available for distribution, since our consolidated cost of sales amounts would also be expected to increase due to comparable increases in the purchase prices of the underlying energy commodities. The same type of relationship would be true in the case of lower energy commodity sales prices and purchase costs.

We attempt to mitigate commodity price exposure through our hedging activities and the use of fee-based arrangements. See Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report and "*Quantitative and Qualitative Disclosures About Market Risk*" under Part I, Item 3 of this quarterly report for information regarding our commodity hedging activities.

Income Statement Highlights

The following table summarizes the key components of our consolidated results of operations for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Revenues	$ 10,831.3	$ 6,922.0	$ 29,436.7	$ 20,155.5
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	8,112.8	4,313.7	21,215.8	12,331.9
Other operating costs and expenses	757.3	696.9	2,174.2	2,120.4
Depreciation, amortization and accretion expenses	511.3	484.2	1,516.9	1,461.3
Asset impairment charges	29.3	77.0	112.7	90.4
Net losses (gains) attributable to asset sales and related matters	(2.2)	(0.6)	9.0	(2.1)
Total operating costs and expenses	9,408.5	5,571.2	25,028.6	16,001.9
General and administrative costs	47.3	50.3	155.1	162.8
Total costs and expenses	9,455.8	5,621.5	25,183.7	16,164.7
Equity in income of unconsolidated affiliates	137.6	82.0	447.2	336.1
Operating income	1,513.1	1,382.5	4,700.2	4,326.9
Other income (expense):				
Interest expense	(315.9)	(320.5)	(954.8)	(958.2)
Other, net	1.0	2.9	2.6	12.5
Total other expense, net	(314.9)	(317.6)	(952.2)	(945.7)
Income before income taxes	1,198.2	1,064.9	3,748.0	3,381.2
Benefit from (provision for) income taxes	(16.1)	19.1	(57.3)	138.6
Net income	1,182.1	1,084.0	3,690.7	3,519.8
Net income attributable to noncontrolling interests	(28.3)	(31.4)	(82.3)	(82.4)
Net income attributable to preferred units	(0.8)	*	(2.7)	*
Net income attributable to common unitholders	$ 1,153.0	$ 1,052.6	$ 3,605.7	$ 3,437.4

** Amount is negligible*

Revenues

The following table presents each business segment's contribution to consolidated revenues for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,169.6	$ 2,048.4	$ 9,151.0	$ 6,401.7
Midstream services	647.0	565.6	1,836.2	1,656.7
Total	3,816.6	2,614.0	10,987.2	8,058.4
Crude Oil Pipelines & Services:				
Sales of crude oil	2,890.0	1,216.1	6,868.2	4,059.7
Midstream services	344.6	305.5	1,035.4	964.0
Total	3,234.6	1,521.6	7,903.6	5,023.7
Natural Gas Pipelines & Services:				
Sales of natural gas	732.2	350.7	2,543.1	1,097.6
Midstream services	247.7	256.2	732.7	765.1
Total	979.9	606.9	3,275.8	1,862.7
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	2,537.8	1,966.2	6,523.6	4,593.7
Midstream services	262.4	213.3	746.5	617.0
Total	2,800.2	2,179.5	7,270.1	5,210.7
Total consolidated revenues	$ 10,831.3	$ 6,922.0	$ 29,436.7	$ 20,155.5

Third Quarter of 2021 Compared to Third Quarter of 2020. Total revenues for the third quarter of 2021 increased $3.91 billion when compared to the third quarter of 2020 primarily due to a $3.75 billion increase in marketing revenues. Revenues from the marketing of NGLs and crude oil increased a combined $2.8 billion quarter-to-quarter primarily due to higher average sales prices, which accounted for a $2.16 billion increase, and higher sales volumes, which accounted for an additional $636.9 million increase. Revenues from the marketing of natural gas, petrochemicals and refined products increased a combined net $953.2 million quarter-to-quarter primarily due to higher average sales prices, which accounted for a $2.13 billion increase, partially offset by lower sales volumes, which accounted for a $1.18 billion decrease.

Revenues from midstream services for the third quarter of 2021 increased $161.1 million when compared to the third quarter of 2020. Revenues from our terminal facilities increased $58.2 million quarter-to-quarter primarily due to higher deficiency fee revenue. Revenues from our natural gas processing facilities increased $46.2 million quarter-to-quarter primarily due to higher market values for the equity NGLs we receive as non-cash consideration for processing services. Revenues from our crude oil pipeline assets increased $43.6 million quarter-to-quarter, primarily due to higher demand for crude oil transportation services. Revenues from our propylene production facilities increased $22.0 million quarter-to-quarter primarily due to higher processing fees.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Total revenues for the nine months ended September 30, 2021 increased $9.28 billion when compared to the nine months ended September 30, 2020 primarily due to an $8.93 billion increase in marketing revenues. Revenues from the marketing of NGLs, natural gas, petrochemicals and refined products increased a combined net $6.12 billion period-to-period primarily due to higher average sales prices, which accounted for a $7.85 billion increase, partially offset by lower sales volumes, which accounted for a $1.73 billion decrease. Revenues from the marketing of crude oil increased $2.81 billion period-to-period primarily due to higher average sales prices, which accounted for a $1.8 billion increase, and higher sales volumes, which accounted for an additional $1.01 billion increase.

Revenues from midstream services for the nine months ended September 30, 2021 increased $348.0 million when compared to the nine months ended September 30, 2020. Revenues from our terminal facilities increased $110.8 million period-to-period primarily due to higher deficiency fee revenue. Revenues from our natural gas processing facilities increased $104.5 million period-to-period primarily due to higher market values for the equity NGLs we receive as non-cash consideration for processing services. Revenues from our crude oil pipeline assets increased $87.9 million period-to-period, primarily due to higher demand for crude oil transportation services. Revenues from our propylene production facilities increased $73.9 million period-to-period primarily due to higher processing fees.

Operating costs and expenses

Total operating costs and expenses for the three and nine months ended September 30, 2021 increased $3.84 billion and $9.03 billion, respectively, when compared to the same periods in 2020.

Cost of sales
Third Quarter of 2021 Compared to Third Quarter of 2020. Cost of sales for the third quarter of 2021 increased $3.8 billion when compared to the third quarter of 2020. The cost of sales associated with our marketing of NGLs and crude oil increased a combined $3.19 billion quarter-to-quarter primarily due to higher average purchase prices, which accounted for a $2.6 billion increase, and higher sales volumes, which accounted for an additional $586.0 million increase. The cost of sales associated with our marketing of natural gas, petrochemicals and refined products increased a combined net $611.1 million quarter-to-quarter primarily due to higher average purchase prices, which accounted for a $1.74 billion increase, partially offset by lower sales volumes, which accounted for a $1.13 billion decrease.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Cost of sales for the nine months ended September 30, 2021 increased $8.88 billion when compared to the nine months ended September 30, 2020. The cost of sales associated with our marketing of NGLs, natural gas, petrochemicals and refined products increased a combined net $5.58 billion period-to-period primarily due to higher average purchase prices, which accounted for a $7.0 billion increase, partially offset by lower sales volumes, which accounted for a $1.42 billion decrease. The cost of sales associated with our marketing of crude oil increased $3.3 billion period-to-period primarily due to higher average purchase prices, which accounted for a $2.37 billion increase, and higher sales volumes, which accounted for an additional $930.5 million increase.

Other operating costs and expenses
Other operating costs and expenses for the third quarter of 2021 increased $60.4 million when compared to the third quarter of 2020 primarily due to higher maintenance and utility costs, ad valorem taxes, and costs attributable to new assets placed into service during or since the respective quarter in 2020. Other operating costs and expenses for the nine months ended September 30, 2021 increased $53.8 million when compared to the nine months ended September 30, 2020 primarily due to higher maintenance and employee compensation costs, ad valorem taxes, and costs attributable to new assets placed into service during or since the respective period in 2020.

Depreciation, amortization and accretion expenses
Depreciation, amortization and accretion expense for the three and nine months ended September 30, 2021 increased a combined $27.1 million and $55.6 million, respectively, when compared to the same periods in 2020. The quarter-to-quarter and period-to-period increases are primarily due to assets placed into full or limited service (e.g., Chambers County Frac X and XI, and the Midland-to-ECHO 3 pipeline) since the end of the respective periods in 2020 and major maintenance activities accounted for under the deferral method.

Under the deferral method, major maintenance costs are capitalized and amortized over the period until the next major overhaul project. We adopted the deferral method for our reaction-based plants in November 2020.

Asset impairment charges
Non-cash asset impairment charges for the three and nine months ended September 30, 2021 decreased $47.7 million and increased $22.3 million, respectively, when compared to the same periods in 2020. We recorded non-cash impairment charges of $44.3 million during the nine months ended September 30, 2021 due to the sale of a coal bed natural gas gathering system and the related Val Verde treating facility, both of which were components of our San Juan Gathering System. The remainder of our asset impairment charges for the three and nine months ended September 30, 2021 and 2020 are attributable to the write-off of assets that are no longer expected to be used or constructed, including the cancellation of the Midland-to-ECHO 4 crude oil pipeline construction project in September 2020.

We are closely monitoring the recoverability of our long-lived assets, investments in unconsolidated affiliates and goodwill in light of the adverse economic effects of the COVID-19 pandemic. If the adverse economic impacts of the pandemic persist for longer periods than currently expected, these developments could result in the recognition of non-cash impairment charges in the future.

General and administrative costs

General and administrative costs for the three and nine months ended September 30, 2021 decreased $3.0 million and $7.7 million, respectively, when compared to the same periods in 2020 primarily due to lower professional services costs.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates for the three and nine months ended September 30, 2021 increased $55.6 million and $111.1 million, respectively, when compared to the same periods in 2020 primarily due to higher earnings from investments in crude oil pipelines.

Operating income

Operating income for the three and nine months ended September 30, 2021 increased $130.6 million and $373.3 million, respectively, when compared to the same periods in 2020 due to the previously described quarter-to-quarter and period-to-period changes.

Interest expense

The following table presents the components of our consolidated interest expense for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Interest charged on debt principal outstanding	$ 322.1	$ 334.9	$ 969.8	$ 1,000.4
Impact of interest rate hedging program, including related amortization	10.2	9.9	29.0	29.2
Interest costs capitalized in connection with construction projects (1)	(23.0)	(34.5)	(63.8)	(96.9)
Other (2)	6.6	10.2	19.8	25.5
Total	$ 315.9	$ 320.5	$ 954.8	$ 958.2

(1) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. Capitalized interest amounts become part of the historical cost of an asset and are charged to earnings (as a component of depreciation expense) on a straight-line basis over the estimated useful life of the asset once the asset enters its intended service. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise. Capitalized interest amounts fluctuate based on the timing of when projects are placed into service, our capital investment levels and the interest rates charged on borrowings.
(2) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization of debt issuance costs.

Interest charged on debt principal outstanding, which is a key driver of interest expense, decreased $12.8 million quarter-to-quarter primarily due to lower debt principal amounts outstanding during the third quarter of 2021. Our weighted-average debt principal balance for the third quarter of 2021 was $29.07 billion compared to $30.27 billion for the third quarter of 2020.

For the nine months ended September 30, 2021, interest charged on debt principal outstanding decreased $30.6 million period-to-period primarily due to lower debt principal amounts outstanding during the nine months ended September 30, 2021, which accounted for an $21.8 million decrease, and the effects of lower overall interest rates during the nine months ended September 30, 2021, which accounted for an additional $8.8 million decrease. Our weighted-average debt principal balance for the nine months ended September 30, 2021 was $29.38 billion compared to $29.84 billion for the nine months ended September 30, 2020.

For additional information regarding our debt obligations, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report. For a discussion of our capital projects, see "*Capital Investments*" within this Part I, Item 2.

Income taxes

The following table presents the components of our consolidated benefit from (provision for) income taxes for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Deferred tax benefit (expense) attributable to OTA	$ (6.8)	$ 21.3	$ (20.1)	$ 158.0
Revised Texas Franchise Tax (“Texas Margin Tax”)	(9.6)	(7.2)	(37.0)	(21.9)
Other	0.3	5.0	(0.2)	2.5
Benefit from (provision for) income taxes	$ (16.1)	$ 19.1	$ (57.3)	$ 138.6

On February 25, 2020, we received notice from Marquard & Bahls AG (“M&B”) of its election to exercise its rights under the Liquidity Option Agreement among the Partnership, OTA Holdings, Inc. (a Delaware corporation previously named Oiltanking Holding Americas, Inc. (“OTA”)), and M&B dated October 1, 2014 (the “Liquidity Option Agreement”). The Partnership settled its obligations under the Liquidity Option Agreement on March 5, 2020 and indirectly assumed the deferred tax liability of OTA, which reflects OTA’s outside basis difference in the limited partner interests it received from the Partnership in October 2014.

At March 5, 2020, the Partnership’s liability recognized in connection with the Liquidity Option Agreement was $511.9 million (referred to as the “Liquidity Option liability”). Upon settlement of the Liquidity Option Agreement, the Liquidity Option liability was effectively replaced by the deferred tax liability of OTA calculated in accordance with ASC 740, *Income Taxes*. Since the book value of the Liquidity Option liability exceeded OTA’s estimated deferred tax liability of $439.7 million on that date, we recognized a non-cash benefit in earnings of $72.2 million, which is reflected in the “Benefit from (provision for) income taxes” line on our Unaudited Condensed Statement of Consolidated Operations for the nine months ended September 30, 2020. OTA recognized an additional net, non-cash deferred income tax benefit of $85.8 million, which reflected a decrease in the outside basis difference of its investment in the Partnership caused by a decline in the market price of the Partnership’s common units subsequent to March 5, 2020 through September 30, 2020. In total, our earnings for the nine months ended September 30, 2020 reflect $158.0 million of deferred income tax benefit attributable to OTA.

On September 30, 2020, OTA exchanged the Partnership common units it owned for non-publicly traded preferred units having a stated value of $1,000 per unit. As a result, beginning September 30, 2020, OTA’s deferred tax liability no longer fluctuates due to market price changes in our common units.

Income tax expense attributable to the Texas Margin Tax increased $2.4 million quarter-to-quarter and $15.1 million period-to-period primarily due to an increase in the Texas apportionment factor and higher Partnership earnings.

Business Segment Highlights

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on our non-generally accepted accounting principle (“non-GAAP”) financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results.

The following table presents gross operating margin by segment and non-GAAP total gross operating margin for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Gross operating margin by segment:				
NGL Pipelines & Services	$ 1,022.9	$ 1,028.1	$ 3,206.9	$ 3,038.2
Crude Oil Pipelines & Services	422.9	481.8	1,242.0	1,569.1
Natural Gas Pipelines & Services	223.3	208.4	960.5	701.1
Petrochemical & Refined Products Services	411.3	315.0	1,019.1	785.0
Total segment gross operating margin (1)	2,080.4	2,033.3	6,428.5	6,093.4
Net adjustment for shipper make-up rights	9.8	(39.9)	46.4	(54.1)
Total gross operating margin (non-GAAP)	$ 2,090.2	$ 1,993.4	$ 6,474.9	$ 6,039.3

(1) Within the context of this table, total segment gross operating margin represents a subtotal and corresponds to measures similarly titled within our business segment disclosures found under Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Total gross operating margin includes equity in the earnings of unconsolidated affiliates, but is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Total gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests. Our calculation of gross operating margin may or may not be comparable to similarly titled measures used by other companies. Segment gross operating margin for NGL Pipelines & Services and Crude Oil Pipelines & Services reflect adjustments for shipper make-up rights that are included in management's evaluation of segment results. However, these adjustments are excluded from non-GAAP total gross operating margin.

The GAAP financial measure most directly comparable to total gross operating margin is operating income. For a discussion of operating income and its components, see the previous section titled "*Income Statement Highlights*" within this Part I, Item 2. The following table presents a reconciliation of operating income to total gross operating margin for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Operating income	$ 1,513.1	$ 1,382.5	$ 4,700.2	$ 4,326.9
Adjustments to reconcile operating income to total gross operating margin (addition or subtraction indicated by sign):				
Depreciation, amortization and accretion expense in operating costs and expenses (1)	502.7	484.2	1,497.9	1,461.3
Asset impairment charges in operating costs and expenses	29.3	77.0	112.7	90.4
Net losses (gains) attributable to asset sales and related matters in operating costs and expenses	(2.2)	(0.6)	9.0	(2.1)
General and administrative costs	47.3	50.3	155.1	162.8
Total gross operating margin (non-GAAP)	$ 2,090.2	$ 1,993.4	$ 6,474.9	$ 6,039.3

(1) Excludes amortization of major maintenance costs for reaction-based plants, which are a component of gross operating margin.

Each of our business segments benefits from the supporting role of our marketing activities. The main purpose of our marketing activities is to support the utilization and expansion of assets across our midstream energy asset network by increasing the volumes handled by such assets, which results in additional fee-based earnings for each business segment. In performing these support roles, our marketing activities also seek to participate in supply and demand opportunities as a supplemental source of gross operating margin for us. The financial results of our marketing efforts fluctuate due to changes in volumes handled and overall market conditions, which are influenced by current and forward market prices for the products bought and sold.

Two major winter storms, Uri and Viola, impacted Texas and the southern U.S. in mid-February 2021 (the "February 2021 winter storms"). The storms had a major impact on the electric power grid in Texas, which resulted in widespread power outages. Voluntarily and in accordance with our agreements with the Electric Reliability Council of Texas, Inc. ("ERCOT"), we temporarily shut down our non-essential plants and other operations in Texas to support residential power consumption. Those Texas assets that remained operational (e.g., our natural gas processing plants, storage facilities and Texas Intrastate System) were impacted by rolling blackouts. The economic impacts of these disruptions, higher power and natural gas costs, as well as losses on natural gas hedges, were mitigated by sales of natural gas to electricity generators, natural gas utilities and industrial customers to assist them in meeting their requirements. During and following the storms, many of our customers also experienced downtime due to freeze-related damage and repairs that impacted our volumes.

Estimated Impact of Hurricane Ida on Results for the Third Quarter of 2021

In late August 2021, southern Louisiana and Mississippi, including its critical energy infrastructure, were impacted by the cumulative effects of Hurricane Ida. Impacts on the energy industry included, but were not limited to, severe flooding and limited access to facilities, disruptions to offshore production in the Gulf of Mexico, and reduced energy demand from area refineries and petrochemical facilities. Our plant, pipeline and storage assets in southern Louisiana and Mississippi did not experience significant property damage, and the majority have returned to normal operations. We expect our volumes impacted by the remaining third-party facility disruptions to return to normal levels as repairs are completed and production is fully restored.

We estimate that Hurricane Ida reduced our gross operating margin for the third quarter of 2021 by approximately $30 million, almost all of which is related to our Louisiana and Mississippi processing, transportation and fractionation assets and related marketing activities, which are a component of our NGL Pipelines & Services segment. Of this amount, approximately $25 million represents the combined net impact of lower than anticipated volumes and lost business opportunities. The remaining $5 million represents expenses, net of property damage insurance reimbursements, which we incurred during the quarter in connection with hurricane-related repair and recovery costs. As a result of our deductible levels, we do not expect any reimbursement from insurance in connection with business interruption claims from Hurricane Ida.

NGL Pipelines & Services

The following table presents segment gross operating margin and selected volumetric data for the NGL Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	$ 263.9	$ 256.8	$ 844.2	$ 708.3
NGL pipelines, storage and terminals	569.6	602.9	1,751.3	1,862.5
NGL fractionation	189.4	168.4	611.4	467.4
Total	$ 1,022.9	$ 1,028.1	$ 3,206.9	$ 3,038.2
Selected volumetric data:				
NGL pipeline transportation volumes (MBPD)	3,481	3,446	3,389	3,563
NGL marine terminal volumes (MBPD)	664	643	661	696
NGL fractionation volumes (MBPD)	1,254	1,350	1,229	1,357
Equity NGL production volumes (MBPD) (1)	150	141	169	156
Fee-based natural gas processing volumes (MMcf/d) (2,3)	3,990	4,105	4,064	4,299

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities.
(2) Volumes reported correspond to the revenue streams earned by our natural gas processing plants.
(3) Fee-based natural gas processing volumes are measured at either the wellhead or plant inlet in MMcf/d.

Natural gas processing and related NGL marketing activities
Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from natural gas processing and related NGL marketing activities for the third quarter of 2021 increased $7.1 million when compared to the third quarter of 2020.

Gross operating margin from our Permian Basin natural gas processing facilities increased $30.3 million quarter-to-quarter primarily due to higher average processing margins (including the impact of hedging), which accounted for a $16.3 million increase, and higher equity NGL production, which accounted for an additional $11.4 million increase. Fee-based natural gas processing volumes and equity NGL volumes at these facilities increased 144 MMcf/d and 33 MBPD, respectively, quarter-to-quarter.

Gross operating margin from our Rockies natural gas processing facilities (Meeker, Pioneer and Chaco) increased a combined $25.9 million quarter-to-quarter primarily due to higher average processing margins (including the impact of hedging activities). On a combined basis, fee-based natural gas processing volumes and equity NGL production at these facilities decreased 160 MMcf/d and 18 MBPD, respectively, quarter-to-quarter.

Gross operating margin from our Louisiana and Mississippi natural gas processing facilities increased $12.7 million quarter-to-quarter primarily due to higher average processing margins (including the impact of hedging activities). Fee-based natural gas processing volumes decreased 70 MMcf/d and equity NGL production increased 3 MBPD, quarter-to-quarter (net to our interest).

Gross operating margin from our South Texas natural gas processing facilities increased a net $4.5 million quarter-to-quarter primarily due to higher average processing margins (including the impact of hedging activities). Fee-based processing volumes and equity NGL production at our South Texas natural gas processing facilities decreased 3 MMcf/d and 5 MBPD, respectively, quarter-to-quarter.

Gross operating margin from our NGL marketing activities decreased $68.9 million quarter-to-quarter primarily due to lower average sales margins (including the impact of hedging activities). Results from NGL marketing strategies that optimize our transportation, storage, plant and export assets decreased a combined $117.9 million quarter-to-quarter, partially offset by higher earnings from non-cash mark-to-market activities, which accounted for a $49.0 million increase.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from natural gas processing and related NGL marketing activities for the nine months ended September 30, 2021 increased $135.9 million when compared to the nine months ended September 30, 2020.

Gross operating margin from our NGL marketing activities increased a net $53.0 million period-to-period primarily due to higher average sales margins (including the impact of hedging activities), which accounted for a $70.5 million increase, partially offset by lower sales volumes, which accounted for a $15.6 million decrease. Results from marketing strategies that optimize our export and storage assets decreased a combined $91.6 million period-to-period, partially offset by higher earnings from the optimization of our transportation and plant assets, which accounted for a $66.9 million increase. In addition, gross operating margin from our NGL marketing activities attributable to non-cash, mark-to-market earnings increased $77.7 million period-to-period.

Gross operating margin from our Permian Basin natural gas processing facilities increased a net $42.8 million period-to-period primarily due to higher fee-based natural gas processing volumes, which accounted for a $29.5 million increase, and higher average processing margins (including the impact of hedging), which accounted for an additional $20.4 million increase, partially offset by higher operating costs, which accounted for a $6.8 million decrease. Fee-based natural gas processing volumes and equity NGL production at these facilities increased 255 MMcf/d and 29 MBPD, respectively, period-to-period.

Gross operating margin from our Rockies natural gas processing facilities increased a combined net $33.5 million period-to-period primarily due to higher average processing margins (including the impact of hedging activities), which accounted for a $34.5 million increase, and lower operating costs, which accounted for an additional $6.3 million increase, partially offset by lower fee-based natural gas processing volumes, which accounted for a $7.9 million decrease. On a combined basis, fee-based natural gas processing volumes and equity NGL production at these facilities decreased 268 MMcf/d and 9 MBPD, respectively, period-to-period.

Gross operating margin from our Louisiana and Mississippi natural gas processing facilities increased a net $26.5 million period-to-period primarily due to higher average processing margins (including the impact of hedging activities), which accounted for a $28.9 million increase, and lower operating costs, which accounted for an additional $5.1 million increase, partially offset by lower average processing fees and volumes, which accounted for decreases of $7.7 million and $3.0 million, respectively. Fee-based natural gas processing volumes decreased 108 MMcf/d period-to-period (net to our interest).

Gross operating margin from our South Texas natural gas processing facilities decreased a net $22.7 million period-to-period primarily due to lower equity NGL production of 7 MBPD, which accounted for a $47.6 million decrease, and lower average processing fees, which accounted for an additional $38.3 million decrease, partially offset by higher average processing margins (including the impact of hedging activities), which accounted for a $67.9 million period-to-period increase. Fee-based processing volumes at these facilities decreased 88 MMcf/d period-to-period.

NGL pipelines, storage and terminals
Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from our NGL pipelines, storage and terminal assets during the third quarter of 2021 decreased $33.3 million when compared to the third quarter of 2020.

A number of our pipelines, including the Mid-America Pipeline System, Seminole NGL Pipeline, Chaparral NGL Pipeline, and Shin Oak NGL Pipeline, serve Permian Basin and/or Rocky Mountain producers. On a combined basis, gross operating margin from these pipelines decreased $30.6 million quarter-to-quarter primarily due to lower average transportation fees, which accounted for a $21.9 million decrease, and lower transportation volumes, which accounted for an additional $7.3 million decrease. Transportation volumes on these pipelines decreased a combined 10 MBPD quarter-to-quarter (net to our interest).

Gross operating margin at our Morgan's Point Ethane Export Terminal increased $6.3 million quarter-to-quarter primarily due to an increase in loading volumes of 23 MBPD, which accounted for a $4.3 million increase, and lower operating costs, which accounted for an additional $2.1 million increase.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from our NGL pipelines, storage and terminal assets during the nine months ended September 30, 2021 decreased $111.2 million when compared to the nine months ended September 30, 2020.

On a combined basis, gross operating margin from our pipelines that serve Permian Basin and/or Rocky Mountain producers decreased a net $58.9 million period-to-period primarily due to lower transportation volumes of 73 MBPD (net to our interest), which accounted for a $54.3 million decrease, and higher operating costs, which accounted for an additional $23.0 million decrease, partially offset by higher handling fee revenues, which accounted for an $11.6 million increase, and higher average transportation fees, which accounted for an additional $6.8 million increase.

Gross operating margin from LPG-related activities at our Enterprise Hydrocarbons Terminal ("EHT") decreased $26.0 million period-to-period primarily due to lower export volumes of 53 MBPD. Gross operating margin from our related Houston Ship Channel Pipeline decreased $4.9 million period-to-period primarily due to a 54 MBPD decrease in transportation volumes. Gross operating margin at our Morgan's Point Ethane Export Terminal increased $7.6 million period-to-period primarily due to higher loading volumes of 18 MBPD.

Gross operating margin from our Dixie Pipeline and related terminals decreased a combined $16.8 million period-to-period primarily due to higher maintenance and other operating costs, which accounted for a $9.6 million decrease, and lower transportation volumes of 20 MBPD, which accounted for an additional $7.3 million decrease.

Gross operating margin from our Chambers County storage complex decreased a net $10.2 million period-to-period primarily due to lower throughput fee revenues, which accounted for a $12.0 million decrease, and higher operating costs, which accounted for an additional $15.2 million decrease, partially offset by higher storage fee revenues, which accounted for a $17.0 million increase.

Gross operating margin from our South Texas NGL Pipeline System increased $12.1 million period-to-period primarily due to higher pipeline capacity fee revenues earned from an affiliate pipeline. Transportation volumes on our South Texas NGL Pipeline System decreased 11 MBPD period-to-period.

NGL fractionation
Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from NGL fractionation during the third quarter of 2021 increased $21.0 million when compared to the third quarter of 2020.

Gross operating margin from our Chambers County NGL fractionation complex increased a net $23.6 million quarter-to-quarter primarily due to higher fractionation volumes, which accounted for a $35.0 million increase, and higher ancillary service revenues, which accounted for an additional $17.1 million increase, partially offset by higher operating costs, which accounted for a $32.8 million decrease. NGL fractionation volumes at our Chambers County NGL fractionation complex, which includes the average daily operating rates for newly constructed assets from the time the asset was placed into service, decreased 40 MBPD quarter-to-quarter (net to our interest). While the average daily operating rate for our Chambers County NGL fractionation complex decreased quarter-to-quarter, total NGL fractionation volumes increased primarily due to a full quarter of contributions from Frac XI, which entered service in September 2020.

Gross operating margin from our Norco NGL fractionator decreased $4.9 million quarter-to-quarter primarily due to higher maintenance costs and lower fractionation volumes as a result of Hurricane Ida. NGL fractionation volumes at our Norco NGL fractionator decreased 22 MBPD quarter-to-quarter.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from NGL fractionation during the nine months ended September 30, 2021 increased $144.0 million when compared to the nine months ended September 30, 2020.

Gross operating margin from our Chambers County NGL fractionation complex increased a net $162.2 million period-to-period. This increase was primarily due to higher fractionation volumes, which accounted for a $107.6 million increase, and higher ancillary service revenues, which accounted for an additional $45.6 million increase, partially offset by higher operating costs, which accounted for a $114.0 million decrease. NGL fractionation volumes at our Chambers County NGL fractionation complex, which includes the average daily operating rates for newly constructed assets from the time the asset was placed into service, decreased 55 MBPD period-to-period (net to our interest). While the average daily operating rate for our Chambers County NGL fractionation complex decreased period-to-period, total NGL fractionation volumes increased primarily due to a full period of contributions from Frac X and Frac XI, which entered service in late March 2020 and September 2020, respectively.

In addition, gross operating margin at our Chambers County NGL fractionation complex increased due to $63.2 million in margins on the optimization of our power supply arrangements and $40.5 million of payments received in connection with our participation in the Texas Load Resources Demand Response Program ("LaaR") during the February 2021 winter storms. The amounts earned from optimization activities were based on the settlement of ERCOT prices, which were finalized by the State of Texas during the second quarter of 2021. The amounts earned from the LaaR program partially compensate us for higher electricity expenses incurred during the storms and for lost revenues resulting from voluntary outages during the storms.

Gross operating margin from our Norco NGL fractionator decreased $16.7 million period-to-period primarily due to higher maintenance costs and lower fractionation volumes as a result of downtime for major maintenance activities during the second quarter of 2021 and Hurricane Ida during the third quarter of 2021. NGL fractionation volumes at our Norco NGL fractionator decreased 21 MBPD period-to-period.

Crude Oil Pipelines & Services

The following table presents segment gross operating margin and selected volumetric data for the Crude Oil Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Segment gross operating margin:				
Midland-to-ECHO System and related business activities	$ 99.8	$ 82.3	$ 274.8	$ 264.7
Other crude oil pipelines, terminals and related marketing results	323.1	399.5	967.2	1,304.4
Total	$ 422.9	$ 481.8	$ 1,242.0	$ 1,569.1
Selected volumetric data:				
Crude oil pipeline transportation volumes (MBPD)	2,047	1,739	2,009	2,008
Crude oil marine terminal volumes (MBPD)	588	662	642	790

Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from our Crude Oil Pipelines & Services segment for the third quarter of 2021 decreased $58.9 million when compared to the third quarter of 2020.

Gross operating margin from our crude oil marketing activities (excluding those attributable to the Midland-to-ECHO System) decreased $71.5 million quarter-to-quarter primarily due to lower average sales margins (including the impact of hedging activities). Results from crude oil marketing strategies that optimize our storage and transportation assets decreased $55.3 million and $18.0 million quarter-to-quarter, respectively.

Gross operating margin from crude oil activities at EHT decreased $8.0 million quarter-to-quarter primarily due to lower storage revenues and other fees. Crude oil terminal volumes at EHT decreased 131 MBPD quarter-to-quarter.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased $5.8 million quarter-to-quarter primarily due to lower average transportation fees. Transportation volumes on our South Texas Crude Oil Pipeline System increased 17 MBPD quarter-to-quarter. Gross operating margin from our West Texas Pipeline System decreased $4.8 million quarter-to-quarter primarily due to lower average transportation fees. Transportation volumes on our West Texas Pipeline System increased 96 MBPD quarter-to-quarter.

Gross operating margin from our Midland-to-ECHO System and related business activities increased a net $17.5 million quarter-to-quarter primarily due to higher transportation volumes of 142 MBPD (net to our interest), which accounted for a $30.5 million increase, partially offset by lower average sales margins from marketing activities, which accounted for a $10.5 million decrease. The net quarter-to-quarter increase in transportation volumes for this system is generally due to the Midland-to-ECHO 3 pipeline, which was placed into service in October 2020.

Gross operating margin from our equity investment in the Seaway Pipeline increased $9.5 million quarter-to-quarter primarily due to higher transportation volumes. Transportation volumes on the Seaway Pipeline increased 49 MBPD quarter-to-quarter (net to our interest).

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from our Crude Oil Pipelines & Services segment for the nine months ended September 30, 2021 decreased $327.1 million when compared to the nine months ended September 30, 2020.

Gross operating margin from our crude oil marketing activities (excluding those attributable to the Midland-to-ECHO System) decreased $273.6 million period-to-period primarily due to lower average sales margins (including the impact of hedging activities). Results from crude oil marketing strategies that optimize our storage and transportation assets decreased $172.8 million and $46.9 million period-to-period, respectively. In addition, gross operating margin attributable to non-cash, mark-to-market earnings decreased $28.1 million period-to-period.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased $37.8 million period-to-period primarily due to lower transportation volumes of 17 MBPD, which accounted for a $20.9 million decrease, and lower average transportation fees, which accounted for an additional $17.7 million decrease. Gross operating margin from our equity investment in the Eagle Ford Crude Oil Pipeline decreased $11.3 million period-to-period primarily due to lower transportation volumes of 52 MBPD (net to our interest).

Gross operating margin from our West Texas Pipeline System decreased $33.1 million period-to-period primarily due to lower average transportation fees. Transportation volumes on our West Texas Pipeline System increased 20 MBPD period-to-period.

Gross operating margin from crude oil activities at EHT decreased $6.7 million period-to-period primarily due to lower storage revenues and other fees. Crude oil terminal volumes at EHT decreased 175 MBPD period-to-period.

Gross operating margin from our equity investment in the Seaway Pipeline increased $32.5 million period-to-period primarily due to LaaR payments from power service providers in connection with the February 2021 winter storms. Transportation volumes on our Seaway Pipeline decreased 61 MBPD period-to-period (net to our interest).

Gross operating margin from our Midland-to-ECHO System and related business activities increased a net $10.1 million period-to-period primarily due to higher transportation volumes of 115 MBPD (net to our interest), which accounted for a $45.8 million increase, and lower operating costs, which accounted for an additional $8.5 million increase, partially offset by lower average sales margins from marketing activities, which accounted for a $46.9 million decrease. As noted previously, the increase in transportation volumes is generally attributable to placing the Midland-to-ECHO 3 pipeline into service during the fourth quarter of 2020.

Natural Gas Pipelines & Services

The following table presents segment gross operating margin and selected volumetric data for the Natural Gas Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Segment gross operating margin	$ 223.3	$ 208.4	$ 960.5	$ 701.1
Selected volumetric data:				
Natural gas pipeline transportation volumes (BBtus/d)	14,556	13,131	14,144	13,322

Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from our Natural Gas Pipelines & Services segment for the third quarter of 2021 increased $14.9 million compared to the third quarter of 2020.

Gross operating margin from our natural gas marketing activities increased $37.5 million quarter-to-quarter primarily due to higher average sales margins, which benefited from higher regional natural gas price spreads in Louisiana and Texas.

Gross operating margin from our Acadian Gas System and Haynesville Gathering System increased a combined $10.1 million quarter-to-quarter primarily due to higher transportation volumes, which accounted for a $5.9 million increase, and higher capacity reservation revenues, which accounted for an additional $4.4 million increase. On a combined basis, transportation volumes increased 543 BBtus/d.

Gross operating margin from our Texas Intrastate System decreased a net $22.1 million quarter-to-quarter primarily due to lower capacity reservation revenues, which accounted for a $33.5 million decrease, partially offset by higher storage and other fees, which accounted for a $5.3 million increase, and higher transportation volumes of 782 BBtus/d, which accounted for an additional $3.8 million increase. The quarter-to-quarter increase in transportation volumes for this system is primarily due to the addition of new firm and interruptible transportation agreements.

Gross operating margin from our Permian Basin Gathering System decreased a net $8.8 million quarter-to-quarter primarily due to lower condensate sales, which accounted for a $9.5 million decrease, partially offset by higher natural gas gathering volumes of 184 BBtus/d, which accounted for a $2.3 million increase. The quarter-to-quarter increase in natural gas gathering volumes is attributable to deliveries at our Orla facility.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from our Natural Gas Pipelines & Services segment for the nine months ended September 30, 2021 increased $259.4 million when compared to the nine months ended September 30, 2020. As noted previously, two major winter storms impacted Texas and the southern U.S. in mid-February 2021. Given the higher demand for natural gas during the storms, we sold natural gas to assist electricity generators, natural gas utilities and industrial customers in meeting their requirements. Gross operating margin from our natural gas marketing activities increased $276.3 million period-to-period primarily due to higher average sales margins (including the impact of hedging activities) in connection with these unusual storm events.

Gross operating margin from our Permian Basin Gathering System increased $36.9 million period-to-period primarily due to higher condensate sales, which accounted for a $29.5 million increase, and higher natural gas gathering volumes of 359 BBtus/d, which accounted for an additional $8.9 million increase. The period-to-period increase in gathering volumes is attributable to deliveries at our Mentone and Orla facilities.

Gross operating margin from our Texas Intrastate System decreased a net $41.3 million period-to-period primarily due to lower capacity reservation revenues, which accounted for an $85.3 million decrease, partially offset by higher storage and other fees, which accounted for a $23.7 million increase, and higher transportation volumes of 596 BBtus/d, which accounted for an additional $14.5 million increase.

Petrochemical & Refined Products Services

The following table presents segment gross operating margin and selected volumetric data for the Petrochemical & Refined Products Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Segment gross operating margin:				
Propylene production and related activities	$ 259.7	$ 133.1	$ 609.5	$ 302.2
Butane isomerization and related operations	27.8	18.7	53.1	44.9
Octane enhancement and related plant operations	45.2	40.0	78.8	145.7
Refined products pipelines and related activities	57.9	101.5	229.8	242.9
Ethylene exports and other services	20.7	21.7	47.9	49.3
Total	$ 411.3	$ 315.0	$ 1,019.1	$ 785.0
Selected volumetric data:				
Propylene production volumes (MBPD)	96	83	98	84
Butane isomerization volumes (MBPD)	108	102	85	92
Standalone deisobutanizer (“DIB”) processing volumes (MBPD)	153	120	155	119
Octane enhancement and related plant sales volumes (MBPD) (1)	39	35	33	34
Pipeline transportation volumes, primarily refined products and petrochemicals (MBPD)	782	844	889	780
Marine terminal volumes, primarily refined products and petrochemicals (MBPD)	264	226	243	249

(1) Reflects aggregate sales volumes for our octane additive and iBDH facilities located at our Chambers County complex and our HPIB facility located adjacent to the Houston Ship Channel.

Propylene production and related activities

Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from propylene production and related activities for the third quarter of 2021 increased $126.6 million when compared to the third quarter of 2020. Gross operating margin from our Chambers County propylene production facilities increased a combined $128.8 million quarter-to-quarter primarily due to higher average sales margins. Propylene and associated by-product production volumes at these facilities increased a combined 12 MBPD quarter-to-quarter (net to our interest).

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from propylene production and related activities for the nine months ended September 30, 2021 increased $307.3 million when compared to the nine months ended September 30, 2020. Gross operating margin from our Chambers County propylene production facilities increased a combined $301.5 million period-to-period primarily due to higher average sales margins, which accounted for a $194.4 million increase, and higher propylene fractionation fees, which accounted for an additional $103.0 million increase. Propylene and associated by-product production volumes at these facilities increased a combined 12 MBPD period-to-period (net to our interest).

Butane isomerization and related operations

Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from butane isomerization and related operations increased $9.1 million quarter-to-quarter primarily due to higher by-product sales.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from butane isomerization and related operations increased $8.2 million period-to-period primarily due to higher by-product sales, which accounted for a $17.3 million increase, partially offset by higher operating costs, which accounted for a $10.5 million decrease.

Octane enhancement and related plant operations
Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from our octane enhancement and related plant operations increased $5.2 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a $9.3 million increase, partially offset by higher operating costs, which accounted for a $5.7 million decrease.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from our octane enhancement and related plant operations decreased $66.9 million period-to-period primarily due to lower average sales margins (including the impact of hedging activities), which accounted for a $41.3 million decrease, lower sales volumes, which accounted for an $8.2 million decrease, and higher operating costs, which accounted for an additional $17.9 million decrease. Production volumes at these facilities for 2021 were lower when compared to 2020 primarily due to planned major maintenance activities, which were completed in the last week of January 2021 for our HPIB plant and the beginning of May 2021 for our octane enhancement plant.

Refined products pipelines and related activities
Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from refined products pipelines and related activities for the third quarter of 2021 decreased $43.6 million when compared to the third quarter of 2020. Gross operating margin from our refined products marketing activities decreased $43.1 million quarter-to-quarter primarily due to lower average sales margins (including the impact of hedging activities).

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from refined products pipelines and related activities for the nine months ended September 30, 2021 decreased $13.1 million when compared to the nine months ended September 30, 2020.

Gross operating margin from our refined products marketing activities decreased a net $27.1 million period-to-period primarily due to lower average sales margins (including the impact of hedging activities), which accounted for a $44.3 million decrease, partially offset by higher sales volumes, which accounted for a $17.6 million increase.

Gross operating margin at our TE Products Pipeline System increased $11.1 million period-to-period primarily due to higher aggregate transportation volumes and related fees. Overall, transportation volumes on our TE Products Pipeline System increased a net 82 MBPD period-to-period.

Ethylene exports and other services
Third Quarter of 2021 Compared to Third Quarter of 2020. Gross operating margin from ethylene exports and other services during the third quarter of 2021 decreased $1.0 million when compared to the third quarter of 2020. Gross operating margin from marine transportation decreased $5.5 million quarter-to-quarter primarily due to higher operating costs. Gross operating margin from our ethylene export terminal and related operations increased $4.4 million quarter-to-quarter primarily due to higher storage revenues and other fees. Loading volumes at our ethylene terminal decreased 3 MBPD (net to our interest).

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Gross operating margin from ethylene exports and other services during the nine months ended September 30, 2021 decreased $1.4 million when compared to the nine months ended September 30, 2020. Gross operating margin from marine transportation decreased $24.2 million period-to-period primarily due to lower average fees and lower fleet utilization rates. Gross operating margin from our ethylene export terminal and its related operations increased $22.7 million period-to-period primarily due to higher loading volumes of 3 MBPD (net to our interest).

Liquidity and Capital Resources

Based on current market conditions (as of the filing date of this quarterly report), we believe that the Partnership and its consolidated businesses will have sufficient liquidity, cash flow from operations and access to capital markets to fund their capital investments and working capital needs for the reasonably foreseeable future. At September 30, 2021, we had $6.7 billion of consolidated liquidity, which was comprised of $4.5 billion of available borrowing capacity under EPO's revolving credit facilities and $2.2 billion of unrestricted cash on hand.

We may issue debt and equity securities to assist us in meeting our future funding and liquidity requirements, including those related to capital investments. We have a universal shelf registration statement on file with the SEC which allows the Partnership and EPO to issue an unlimited amount of equity and debt securities, respectively.

Enterprise Declares Cash Distribution for Third Quarter of 2021

On October 12, 2021, we announced that the Board declared a quarterly cash distribution of $0.45 per common unit, or $1.80 per unit on an annualized basis, to be paid to the Partnership's common unitholders with respect to the third quarter of 2021. The quarterly distribution is payable on November 12, 2021 to unitholders of record as of the close of business on October 29, 2021. The total amount to be paid is $989.7 million, which includes $7.8 million for distribution equivalent rights on phantom unit awards.

The payment of quarterly cash distributions is subject to management's evaluation of our financial condition, results of operations and cash flows in connection with such payments and Board approval. In light of current economic conditions, management will evaluate any future increases in cash distributions on a quarterly basis.

Consolidated Debt

At September 30, 2021, the average maturity of EPO's consolidated debt obligations was approximately 20.9 years. The following table presents the scheduled maturities of principal amounts of EPO's consolidated debt obligations at September 30, 2021 for the years indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	Remainder of 2021	2022	2023	2024	2025	Thereafter
Senior Notes	$ 27,175.0	$ –	$ 1,400.0	$ 1,250.0	$ 850.0	$ 1,150.0	$ 22,525.0
Junior Subordinated Notes	2,646.4	–	–	–	–	–	2,646.4
Total	$ 29,821.4	$ –	$ 1,400.0	$ 1,250.0	$ 850.0	$ 1,150.0	$ 25,171.4

In February 2021, EPO repaid all of the $750.0 million in principal amount of its Senior Notes TT using remaining cash on hand attributable to its August 2020 senior notes offering and proceeds from the issuance of short-term notes under its commercial paper program.

In March 2021, EPO redeemed all of the $575.0 million outstanding principal amount of its Senior Notes RR one month prior to their scheduled maturity in April 2021. These notes were redeemed at par (i.e., at a redemption price equal to the outstanding principal amount of such notes to be redeemed, plus accrued and unpaid interest thereon) using proceeds from the issuance of short-term notes under its commercial paper program.

In September 2021, EPO entered into a new 364-Day Revolving Credit Agreement (the "September 2021 364-Day Revolving Credit Agreement") that replaced its September 2020 364-Day Revolving Credit Agreement. The September 2021 364-Day Revolving Credit Agreement matures in September 2022. EPO's borrowing capacity was unchanged from the prior 364-day revolving credit agreement. As of September 30, 2021, there are no principal amounts outstanding under this new revolving credit agreement.

In September 2021, EPO entered into a new revolving credit agreement that matures in September 2026 (the "September 2021 Multi-Year Revolving Credit Agreement"). The September 2021 Multi-Year Revolving Credit Agreement replaced EPO's prior multi-year revolving credit agreement that was scheduled to mature in September 2024. EPO's borrowing capacity decreased from $3.5 billion under the prior multi-year revolving credit agreement to $3.0 billion (which may be increased by up to $500.0 million to $3.5 billion at EPO's election, provided certain conditions are met) under the September 2021 Multi-Year Revolving Credit agreement. As of September 30, 2021, there are no principal amounts outstanding under this new revolving credit agreement.

In September 2021, EPO issued $1.0 billion in principal amount of senior notes due February 2053 ("Senior Notes EEE"). Senior Notes EEE were issued at 99.170% of their principal amount and have a fixed rate of interest of 3.30% per year. Net proceeds from the issuance of these senior notes will be used for general company purposes, including for growth capital investments, and the repayment of debt (including the repayment of a portion of our $750.0 million in principal amount of 3.50% Senior Notes VV and/or a portion of our $650.0 million in principal amount of 4.05% Senior Notes CC, in each case at their maturity in February 2022).

For additional information regarding our consolidated debt obligations, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Credit Ratings

As of November 8, 2021, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's, Baa1 from Moody's and BBB+ from Fitch Ratings. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's, P-2 from Moody's and F-2 from Fitch Ratings. EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

Common Unit Repurchases Under 2019 Buyback Program

In January 2019, we announced that the Board had approved a $2.0 billion multi-year unit buyback program (the "2019 Buyback Program"), which provides the Partnership with an additional method to return capital to investors. The Partnership repurchased an aggregate 3,367,377 and 4,077,193 common units through open market purchases during the three and nine months ended September 30, 2021, respectively. The total cost of these repurchases, including commissions and fees, was $74.9 million and $88.8 million, respectively. As of September 30, 2021, the remaining available capacity under the 2019 Buyback Program was $1.64 billion.

Cash Flow Statement Highlights

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods indicated (dollars in millions).

	For the Nine Months Ended September 30,	
	2021	**2020**
Net cash flows provided by operating activities	$ 6,387.3	$ 4,291.6
Cash used in investing activities	1,721.5	2,564.2
Cash used in financing activities	3,465.8	1,006.3

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. Changes in energy commodity prices may impact the demand for natural gas, NGLs, crude oil, petrochemical and refined products, which could impact sales of our products and the demand for our midstream services. Changes in demand for our products and services may be caused by other factors, including prevailing economic conditions, reduced demand by consumers for the end products made with hydrocarbon products, increased competition, public health emergencies, adverse weather conditions and government regulations affecting prices and production levels. We may also incur credit and price risk to the extent customers do not fulfill their contractual obligations to us in connection with our marketing activities and long-term take-or-pay agreements. For a more complete discussion of these and other risk factors, see "*Risk Factors*" included under Part I, Item 1A of the 2020 Form 10-K.

For additional information regarding our cash flow amounts, please refer to our Unaudited Condensed Statements of Consolidated Cash Flows included under Part I, Item 1 of this quarterly report.

The following information highlights significant period-to-period fluctuations in our consolidated cash flow amounts:

Operating activities
Net cash flows provided by operating activities for the nine months ended September 30, 2021 increased $2.1 billion when compared to the nine months ended September 30, 2020 primarily due to:

- a $1.02 billion period-to-period increase primarily due to the timing of cash receipts and payments related to operations;

- a $715.9 million period-to-period increase attributable to the return of working capital employed in our marketing activities primarily related to storage optimization strategies;

- a $288.1 million period-to-period increase resulting from higher partnership earnings (determined by adjusting our $170.9 million period-to-period increase in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows); and

- a $68.5 million period-to-period increase in cash distributions received on earnings from unconsolidated affiliates primarily attributable to our investments in crude oil pipelines.

For information regarding significant period-to-period changes in our consolidated net income and underlying segment results, see "*Income Statement Highlights*" and "*Business Segment Highlights*" within this Part I, Item 2.

Investing activities
Cash used in investing activities during the nine months ended September 30, 2021 decreased $842.7 million when compared to the nine months ended September 30, 2020 primarily due to an $865.9 million period-to-period decrease in investments for property, plant and equipment (see "*Capital Investments*" within this Part I, Item 2 for additional information).

Financing activities
Cash used in financing activities during the nine months ended September 30, 2021 increased $2.46 billion when compared to the nine months ended September 30, 2020. The period-to-period increase was primarily due to a net cash outflow of $273.2 million related to debt during the nine months ended September 30, 2021 compared to a net cash inflow of $2.19 billion during the nine months ended September 30, 2020. During the nine months ended September 30, 2021, we repaid $1.33 billion aggregate principal amount of senior notes, partially offset by the issuance of $1.0 billion principal amount of senior notes. During the nine months ended September 30, 2020, we issued $4.25 billion aggregate principal amount of senior notes, partially offset by the repayment of $1.5 billion aggregate principal amount of senior notes. In addition, net repayments of short term notes under EPO's commercial paper program were $481.8 million during the nine months ended September 30, 2020.

Non-GAAP Cash Flow Measures

Distributable Cash Flow
Our partnership agreement requires us to make quarterly distributions to our common unitholders of all available cash, after any cash reserves established by Enterprise GP in its sole discretion. Cash reserves include those for the proper conduct of our business, including those for capital investments, debt service, working capital, operating expenses, common unit repurchases, commitments and contingencies and other amounts. The retention of cash allows us to reinvest in our growth and reduce our future reliance on the equity and debt capital markets.

We measure available cash by reference to distributable cash flow ("DCF"), which is a non-GAAP cash flow measure. DCF is an important financial measure for our limited partners since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flows at a level that can sustain our declared quarterly cash distributions. DCF is also a quantitative standard used by the investment community with respect to publicly traded partnerships since the value of a partnership unit is, in part, measured by its yield, which is based on the amount of cash distributions a partnership can pay to a unitholder. Our management compares the DCF we generate to the cash distributions we expect to pay our common unitholders. Using this metric, management computes our distribution coverage ratio. Our calculation of DCF may or may not be comparable to similarly titled measures used by other companies.

Based on the level of available cash each quarter, management proposes a quarterly cash distribution rate to the Board, which has sole authority in approving such matters. Enterprise GP has a non-economic ownership interest in the Partnership and is not entitled to receive any cash distributions from it based on incentive distribution rights or other equity interests.

Our use of DCF for the limited purposes described above and in this quarterly report is not a substitute for net cash flows provided by operating activities, which is the most comparable GAAP measure to DCF. For a discussion of net cash flows provided by operating activities, see "*Cash Flow Statement Highlights*" within this Part I, Item 2.

The following table summarizes our calculation of DCF for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Net income attributable to common unitholders (GAAP) (1)	$ 1,153.0	$ 1,052.6	$ 3,605.7	$ 3,437.4
Adjustments to net income attributable to common unitholders to derive DCF (addition or subtraction indicated by sign):				
Depreciation, amortization and accretion expenses	534.9	513.4	1,593.7	1,545.1
Cash distributions received from unconsolidated affiliates (2)	147.8	146.7	447.1	462.3
Equity in income of unconsolidated affiliates	(137.6)	(82.0)	(447.2)	(336.1)
Asset impairment charges	29.4	77.0	112.9	90.4
Change in fair market value of derivative instruments	(47.5)	37.7	(86.3)	(53.7)
Change in fair value of Liquidity Option	–	–	–	2.3
Deferred income tax expense (benefit)	9.0	(18.3)	33.1	(149.0)
Sustaining capital expenditures (3)	(70.3)	(83.1)	(330.9)	(226.0)
Other, net (4)	(13.3)	(1.3)	(112.4)	30.1
Operational DCF (5)	$ 1,605.4	$ 1,642.7	$ 4,815.7	$ 4,802.8
Proceeds from asset sales	7.8	4.3	58.1	8.4
Monetization of interest rate derivative instruments accounted for as cash flow hedges	–	–	75.2	(33.3)
DCF (non-GAAP)	$ 1,613.2	$ 1,647.0	$ 4,949.0	$ 4,777.9
Cash distributions paid to common unitholders with respect to period, including distribution equivalent rights on phantom unit awards	$ 989.7	$ 978.5	$ 2,972.6	$ 2,938.1
Cash distribution per common unit declared by Enterprise GP with respect to period (6)	$ 0.4500	$ 0.4450	$ 1.3500	$ 1.3350
Total DCF retained by the Partnership with respect to period (7)	$ 623.5	$ 668.5	$ 1,976.4	$ 1,839.8
Distribution coverage ratio (8)	1.6x	1.7x	1.7x	1.6x

(1) For a discussion of the primary drivers of changes in our comparative income statement amounts, see “Income Statement Highlights” within this Part I, Item 2.
(2) Reflects aggregate distributions received from unconsolidated affiliates attributable to both earnings and the return of capital.
(3) Sustaining capital expenditures include cash payments and accruals applicable to the period.
(4) The nine months ended September 30, 2021 includes $100 million of trade accounts receivable that we do not expect to collect in the normal billing cycle.
(5) Represents DCF before proceeds from asset sales and the monetization of interest rate derivative instruments accounted for as cash flow hedges.
(6) See Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for information regarding our cash distributions declared with respect to the periods indicated.
(7) Cash retained by the Partnership may be used for capital investments, debt service, working capital, operating expenses, common unit repurchases, commitments and contingencies and other amounts. The retention of cash reduces our reliance on the capital markets.
(8) Distribution coverage ratio is determined by dividing DCF by total cash distributions paid to common unitholders and in connection with distribution equivalent rights with respect to the period.

The following table presents a reconciliation of net cash flows provided by operating activities to DCF for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Net cash flows provided by operating activities (GAAP)	$ 2,370.3	$ 1,097.8	$ 6,387.3	$ 4,291.6
Adjustments to reconcile net cash flows provided by operating activities to DCF (addition or subtraction indicated by sign):				
Net effect of changes in operating accounts	(647.9)	603.0	(1,047.1)	692.0
Sustaining capital expenditures	(70.3)	(83.1)	(330.9)	(226.0)
Distributions received from unconsolidated affiliates attributable to the return of capital	4.3	66.9	41.2	124.9
Proceeds from asset sales	7.8	4.3	58.1	8.4
Net income attributable to noncontrolling interests	(28.3)	(31.4)	(82.3)	(82.4)
Monetization of interest rate derivative instruments accounted for as cash flow hedges	–	–	75.2	(33.3)
Other, net	(22.7)	(10.5)	(152.5)	2.7
DCF (non-GAAP)	$ 1,613.2	$ 1,647.0	$ 4,949.0	$ 4,777.9

Free Cash Flow

Free Cash Flow ("FCF"), a non-GAAP cash flow measure that is widely used by investors and other participants in the financial community, reflects how much cash flow a business generates during a period after accounting for all capital investments, including those for growth and sustaining capital projects. By comparison, only sustaining capital expenditures are reflected in DCF.

We believe that FCF is important to traditional investors since it reflects the amount of cash available for reducing debt, investing in additional capital projects, paying distributions, common unit repurchases and similar matters. Since business partners fund certain capital projects of our consolidated subsidiaries, our determination of FCF reflects the amount of cash contributed from and distributed to noncontrolling interests. Our calculation of FCF may or may not be comparable to similarly titled measures used by other companies.

Our use of FCF for the limited purposes described above and in this report is not a substitute for net cash flows provided by operating activities, which is the most comparable GAAP measure to FCF.

FCF fluctuates quarter-to-quarter based on a number of factors including earnings, the level of investing activities, the timing of operating cash receipts and payments, and contributions from noncontrolling interests. The following table summarizes our calculation of FCF for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2021	2020	2021	2020
Net cash flows provided by operating activities (GAAP)	$ 2,370.3	$ 1,097.8	$ 6,387.3	$ 4,291.6
Adjustments to net cash flows provided by operating activities to derive FCF (addition or subtraction indicated by sign):				
Cash used in investing activities	(492.8)	(633.7)	(1,721.5)	(2,564.2)
Cash contributions from noncontrolling interests	4.9	1.5	23.0	21.2
Cash distributions paid to noncontrolling interests	(43.7)	(36.0)	(115.1)	(97.8)
FCF (non-GAAP)	$ 1,838.7	$ 429.6	$ 4,573.7	$ 1,650.8

The elements used in calculating FCF are sourced directly from our Unaudited Condensed Statements of Consolidated Cash Flows presented under Part I, Item 1 of this quarterly report. For a discussion of significant quarter-to-quarter changes in our cash flow statement amounts, see "*Cash Flow Statement Highlights*" within this Part I, Item 2.

Capital Investments

The following table summarizes our capital investments for the periods indicated (dollars in millions):

	For the Nine Months Ended September 30,	
	2021	2020
Capital investments for property, plant and equipment: (1)		
Growth capital projects (2)	$ 1,473.6	$ 2,440.2
Sustaining capital projects (3)	332.1	231.4
Total	$ 1,805.7	$ 2,671.6
Investments in unconsolidated affiliates	$ 1.3	$ 9.9

(1) Growth and sustaining capital amounts are presented on a cash basis. In total, these amounts represent "Capital expenditures" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.
(2) Growth capital projects either (a) result in new sources of cash flow due to enhancements of or additions to existing assets (e.g., additional revenue streams, cost savings resulting from debottlenecking of a facility, etc.) or (b) expand our asset base through construction of new facilities that will generate additional revenue streams and cash flows.
(3) Sustaining capital projects are capital expenditures (as defined by GAAP) resulting from improvements to existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues or result in significant cost savings. Sustaining capital expenditures include the costs of major maintenance activities at our reaction-based plants, which are accounted for using the deferral method.

As of September 30, 2021, we have $2.9 billion of growth capital projects scheduled to be placed into service by the end of 2023. This includes a natural gasoline hydrotreater facility at our Chambers County complex, which was placed into service in October 2021, the Gillis Lateral natural gas pipeline and its related infrastructure in the fourth quarter of 2021 and our PDH 2 facility in the second quarter of 2023.

Based on information currently available, we expect our total capital investments for 2021, net of expected contributions from noncontrolling interests, to approximate $2.2 billion for sanctioned projects, which reflects growth capital investments of $1.7 billion and sustaining capital expenditures of $440 million. In addition, we currently expect our growth capital investments in 2022 for sanctioned projects to approximate $800 million; however, growth capital expenditures for 2022 could ultimately be in the range of $1.0 billion to $1.5 billion considering projects currently under development. These amounts do not include capital investments associated with our proposed deepwater offshore crude oil terminal (the Sea Port Oil Terminal, or SPOT), which remains subject to governmental approvals. We currently anticipate receiving approval for SPOT as early as mid-2022; however, we can give no assurance as to whether the project will ultimately be approved or the timing of such decision.

Our forecast of capital investments is dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, the issuance of additional equity and debt securities, and potential divestitures. We may revise our forecast of capital investments due to factors beyond our control, such as adverse economic conditions, weather-related issues and changes in supplier prices. Furthermore, our forecast of capital investments may change due to decisions made by management at a later date, which may include unforeseen acquisition opportunities. Our success in raising capital, including partnering with other companies to share project costs and risks, continues to be a significant factor in determining how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future growth needs and, although we expect to make the forecast capital investments noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital market conditions.

Comparison of Nine Months Ended September 30, 2021 with Nine Months Ended September 30, 2020

In total, investments in growth capital projects decreased $966.6 million period-to-period primarily due to the following:

- completion of projects associated with crude oil pipelines (e.g., expansion projects involving the Midland-to-ECHO System and related crude oil-related infrastructure supporting Permian Basin producers), which accounted for a combined $361.3 million decrease;

- completion of projects at our Chambers County complex (e.g., the completion of Frac X and Frac XI), which accounted for a $316.7 million decrease;

- lower investments in Permian Basin natural gas processing facilities and related infrastructure, which accounted for a $68.7 million decrease; and

- lower investments in projects related to our ethylene business, which accounted for a $52.6 million decrease.

Investments attributable to sustaining capital projects increased $100.7 million period-to-period primarily due to the cost of major maintenance activities performed during the nine months ended September 30, 2021 at certain of our reaction-based plants (PDH 1, octane enhancement and high purity isobutylene facilities). These costs accounted for $97.0 million of the period-to-period increase in sustaining capital investments. For reaction-based plants, we use the deferral method when accounting for major maintenance activities. Under the deferral method, major maintenance costs are capitalized and amortized over the period until the next major overhaul project. We adopted the deferral method for our reaction-based plants in November 2020. Historically, the costs of major maintenance activities attributable to our reaction-based facilities, principally our octane enhancement assets, were not material to our consolidated financial statements.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2020 Form 10-K. The following types of estimates, in our opinion, are subjective in nature, require the exercise of professional judgment and involve complex analysis:

- depreciation methods and estimated useful lives of property, plant and equipment;

- measuring recoverability of long-lived assets and fair value of equity method investments;

- valuation and amortization methods of customer relationships and contract-based intangible assets;

- methods we employ to measure the fair value of goodwill and related assets; and

- the use of estimates for revenue and expenses.

When used to prepare our Unaudited Condensed Consolidated Financial Statements, the foregoing types of estimates are based on our current knowledge and understanding of the underlying facts and circumstances. Such estimates may be revised as a result of changes in the underlying facts and circumstances. Subsequent changes in these estimates may have a significant impact on our consolidated financial position, results of operations and cash flows.

Other Items

Parent-Subsidiary Guarantor Relationship

The Partnership (the “Parent Guarantor”) has guaranteed the payment of principal and interest on the consolidated debt obligations of EPO (the “Subsidiary Issuer”), with the exception of the remaining debt obligations of TEPPCO Partners, L.P. (collectively, the “Guaranteed Debt”). If EPO were to default on any of its Guaranteed Debt, the Partnership would be responsible for full and unconditional repayment of such obligations. At September 30, 2021, the total amount of Guaranteed Debt was $30.03 billion, which was comprised of $27.17 billion of EPO’s senior notes, $2.63 billion of EPO’s junior subordinated notes and $225.1 million of related accrued interest.

The Partnership’s guarantees of EPO’s senior note obligations, commercial paper notes and borrowings under bank credit facilities represent unsecured and unsubordinated obligations of the Partnership that rank equal in right of payment to all other existing or future unsecured and unsubordinated indebtedness of the Partnership. In addition, these guarantees effectively rank junior in right of payment to any existing or future indebtedness of the Partnership that is secured and unsubordinated, to the extent of the assets securing such indebtedness.

The Partnership's guarantees of EPO's junior subordinated notes represent unsecured and subordinated obligations of the Partnership that rank equal in right of payment to all other existing or future subordinated indebtedness of the Partnership and senior in right of payment to all existing or future equity securities of the Partnership. The Partnership's guarantees of EPO's junior subordinated notes effectively rank junior in right of payment to (i) any existing or future indebtedness of the Partnership that is secured, to the extent of the assets securing such indebtedness and (ii) all other existing or future unsecured and unsubordinated indebtedness of the Partnership.

The Partnership may be released from its guarantee obligations only in connection with EPO's exercise of its legal or covenant defeasance options as described in the underlying agreements.

Selected Financial Information of Obligor Group

The following tables present summarized financial information of the Partnership (as Parent Guarantor) and EPO (as Subsidiary Issuer) on a combined basis (collectively, the "Obligor Group"), after the elimination of intercompany balances and transactions among the Obligor Group.

In accordance with Rule 13.01 of Regulation S-X, the summarized financial information of the Obligor Group excludes the Obligor Group's equity in income and investments in the consolidated subsidiaries of EPO that are not party to the guarantee obligations (the "Non-Obligor Subsidiaries"). The total carrying value of the Obligor Group's investments in the Non-Obligor Subsidiaries was $45.62 billion at September 30, 2021. The Obligor Group's equity in the earnings of the Non-Obligor Subsidiaries for the nine months ended September 30, 2021 was $3.15 billion. Although the net assets and earnings of the Non-Obligor Subsidiaries are not directly available to the holders of the Guaranteed Debt to satisfy the repayment of such obligations, there are no significant restrictions on the ability of the Non-Obligor Subsidiaries to pay distributions or make loans to EPO or the Partnership. EPO exercises control over the Non-Obligor Subsidiaries. We continue to believe that the unaudited condensed consolidated financial statements of the Partnership presented under Part I, Item 1 of this quarterly report provide a more appropriate view of our credit standing. Our investment grade credit ratings are based on the Partnership's consolidated financial statements and not the Obligor Group's financial information presented below.

The following table presents summarized balance sheet information for the combined Obligor Group at the dates indicated (dollars in millions):

Selected asset information:	September 30, 2021	December 31, 2020
Current receivables from Non-Obligor Subsidiaries	$ 691.1	$ 775.4
Other current assets	8,233.5	5,805.7
Long-term receivables from Non-Obligor Subsidiaries	187.3	187.3
Other noncurrent assets, excluding investments in Non-Obligor Subsidiaries of $45.62 billion at September 30, 2021 and $45.98 billion at December 31, 2020	8,678.3	8,198.5
Selected liability information:		
Current portion of Guaranteed Debt, including interest of $225.1 million at September 30, 2021 and $455.6 million at December 31, 2020	$ 1,624.4	$ 1,780.6
Current payables to Non-Obligor Subsidiaries	1,403.3	1,129.0
Other current liabilities	5,928.9	3,858.6
Noncurrent portion of Guaranteed Debt, principal only	28,406.8	28,806.8
Noncurrent payables to Non-Obligor Subsidiaries	27.0	27.0
Other noncurrent liabilities	61.9	42.9
Mezzanine equity of Obligor Group:		
Preferred units	$ 49.3	$ 49.3

The following table presents summarized income statement information for the combined Obligor Group for the periods indicated (dollars in millions):

	For the Nine Months Ended September 30, 2021	For the Twelve Months Ended December 31, 2020
Revenues from Non-Obligor Subsidiaries	$ 10,939.8	$ 2,602.4
Revenues from other sources	10,303.6	15,361.4
Operating income of Obligor Group	1,461.6	1,069.7
Net income (loss) of Obligor Group excluding equity in earnings of Non-Obligor Subsidiaries of $3.15 billion for the nine months ended September 30, 2021 and $3.54 billion for the twelve months ended December 31, 2020	457.6	(157.0)

Contractual Obligations

We have contractual future product purchase commitments for natural gas, NGLs, crude oil, petrochemicals and refined products representing enforceable and legally binding agreements as of the reporting date. Our product purchase commitments increased from $14.8 billion at December 31, 2020 to $22.1 billion at September 30, 2021 primarily due to an increase in crude oil and NGL prices between the two reporting dates.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our financial position, results of operations and cash flows.

Related Party Transactions

For information regarding our related party transactions, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

General

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with assets, liabilities and certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We assess the risk associated with each of our derivative instrument portfolios using a sensitivity analysis model. This approach measures the change in fair value of the derivative instrument portfolio based on a hypothetical 10% change in the underlying interest rates or quoted market prices on a particular day. In addition to these variables, the fair value of each portfolio is influenced by changes in the notional amounts of the instruments outstanding and the discount rates used to determine the present values. The sensitivity analysis approach does not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate. Therefore, the impact on the fair value of a derivative instrument resulting from a change in interest rates or quoted market prices (as applicable) would normally be offset by a corresponding gain or loss on the hedged debt instrument, inventory value or forecasted transaction assuming:

- the derivative instrument functions effectively as a hedge of the underlying risk;
- the derivative instrument is not closed out in advance of its expected term; and
- the hedged forecasted transaction occurs within the expected time period.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. Accordingly, the nature and volume of our derivative instruments may change depending on the specific exposure being managed.

Commodity Hedging Activities

The price of energy commodities such as of natural gas, NGLs, crude oil, petrochemicals and refined products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps and basis swaps.

At September 30, 2021, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging the fair value of commodity products held in inventory and (iii) hedging natural gas processing margins. For a summary of our portfolio of commodity derivative instruments outstanding, see Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Sensitivity Analysis

The following tables show the effect of hypothetical price movements on the estimated fair values of our principal commodity derivative instrument portfolios at the dates indicated (dollars in millions).

The fair value information presented in the sensitivity analysis tables excludes the impact of applying Chicago Mercantile Exchange ("CME") Rule 814, which deems that financial instruments cleared by the CME are settled daily in connection with variation margin payments. As a result of this exchange rule, CME-related derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes; however, the derivatives remain outstanding and subject to future commodity price fluctuations until they are settled in accordance with their contractual terms. Derivative transactions cleared on exchanges other than the CME (e.g., the Intercontinental Exchange or ICE) continue to be reported on a gross basis.

Natural gas marketing portfolio

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2020**	**September 30, 2021**	**October 15, 2021**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 3.7	$ (3.1)	$ 0.2
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	2.6	(4.8)	(1.1)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	4.9	(1.4)	1.6

NGL and refined products marketing, natural gas processing and octane enhancement portfolio

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2020**	**September 30, 2021**	**October 15, 2021**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (388.2)	$ (399.8)	$ (371.8)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(521.0)	(413.6)	(381.2)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(255.4)	(386.1)	(362.3)

Crude oil marketing portfolio

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2020**	**September 30, 2021**	**October 15, 2021**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (184.3)	$ (71.0)	$ (127.6)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(266.5)	(136.6)	(200.9)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(102.1)	(5.5)	(54.3)

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward-starting swaps, options to enter into forward-starting swaps ("swaptions"), and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy may be used in controlling our overall cost of capital associated with such borrowings.

As a result of market conditions in March 2021, we terminated our entire portfolio of forward-starting swaps, representing an aggregate $1.08 billion in notional value. As of the filing date of this quarterly report, we do not have any interest rate hedging derivative instruments outstanding.

ITEM 4. CONTROLS AND PROCEDURES.

Disclosure Controls and Procedures

As of the end of the period covered by this quarterly report, our management carried out an evaluation, with the participation of (i) A. James Teague, Co-Chief Executive Officer of Enterprise GP and (ii) W. Randall Fowler, Co-Chief Executive Officer and Chief Financial Officer of Enterprise GP, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this quarterly report, Messrs. Teague and Fowler concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the third quarter of 2021, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Section 302 and 906 Certifications

The required certifications of Messrs. Teague and Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this quarterly report (see Exhibits 31 and 32 under Part II, Item 6 of this quarterly report).

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We will vigorously defend the Partnership in litigation matters.

For additional information regarding our litigation matters, see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

On occasion, we are assessed monetary penalties by governmental authorities related to administrative or judicial proceedings involving environmental matters. In July 2021, we received a civil penalty demand from the U.S. Department of Justice and the State of Colorado regarding alleged violations of hydrocarbon leak detection and repair regulations applicable to our Meeker gas processing plant in Colorado. The eventual resolution of this matter may result in monetary sanctions in excess of $0.3 million; however, we do not expect such expenditures to be material to our consolidated financial statements.

ITEM 1A. RISK FACTORS.

An investment in our securities involves certain risks. Security holders and potential investors in our securities should carefully consider the risks described under “*Risk Factors*” set forth in Part I, Item 1A of our 2020 Form 10-K, in addition to other information in such annual report and this quarterly report. The risk factors set forth in our 2020 Form 10-K are important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Recent Issuance of Unregistered Securities

Holders of our Series A Cumulative Convertible Preferred Units are entitled to receive cumulative quarterly distributions at a rate of 7.25% per annum. We may satisfy our obligation to pay distributions to the preferred unitholders through the issuance, in whole or in part, of additional preferred units (referred to as paid-in-kind or "PIK" distributions), with the remainder in cash, subject to certain rights of a holder to elect all cash and other conditions as described in our partnership agreement.

The Partnership made quarterly PIK distributions to preferred unitholders in the first, second and third quarters of 2021 of an aggregate 15,931, 15,940 and 16,229 preferred units, respectively. With the exception of 274 preferred units distributed in the first quarter of 2021 to a privately held EPCO affiliate, all of the PIK distributions made during the nine months ended September 30, 2021 were to OTA. The preferred units held by OTA are accounted for as treasury units in consolidation. For additional information regarding the preferred units, see Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

The issuances of the preferred units as PIK distributions during the three and nine months ended September 30, 2021 were undertaken in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

Other than as described above, there were no sales of unregistered equity securities during the third quarter of 2021.

Issuer Purchases of Equity Securities

The following table summarizes our equity repurchase activity during the third quarter of 2021:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number Of Units Purchased as Part of 2019 Buyback Program	Remaining Dollar Amount of Units That May Be Purchased Under the 2019 Buyback Program ($ thousands)
2019 Buyback Program: (1)				
July 2021	–	$ –	–	$ 1,718,911
August 2021	2,633,836	$ 22.29	2,633,836	$ 1,660,191
September 2021	733,541	$ 21.90	733,541	$ 1,644,128
Vesting of phantom unit awards:				
July 2021	–	$ –	n/a	n/a
August 2021 (2)	41,555	$ 22.37	n/a	n/a
September 2021	–	$ –	n/a	n/a

(1) In January 2019, we announced the 2019 Buyback Program, which authorized the repurchase of up to $2 billion of EPD's common units. Units repurchased under this program are cancelled immediately upon acquisition.
(2) Of the 157,220 phantom unit awards that vested in August 2021 and converted to common units, 41,555 units were sold back to us by employees to cover related withholding tax requirements. These repurchases are not part of any announced program. We cancelled these units immediately upon acquisition.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

None.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

ITEM 5. OTHER INFORMATION.

None.

ITEM 6. EXHIBITS.

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
2.8	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010).
2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).

2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
2.12	Contribution and Purchase Agreement, dated as of October 1, 2014, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc. and OTB Holdco, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2014).
2.13	Agreement and Plan of Merger, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPOT MergerCo LLC, Oiltanking Partners, L.P. and OTLP GP, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed November 12, 2014).
2.14	Amendment No. 1 dated as of June 6, 2018 to Contribution and Purchase Agreement, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc., Enterprise Products Holdings LLC and Marquard & Bahls, AG (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 12, 2018).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Seventh Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated as of September 30, 2020 (incorporated by reference to Exhibit 3.1 to Form 8-K filed October 1, 2020).
3.4	Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC) (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.5	Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC), filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.6	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
3.7	Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC, dated effective as of April 26, 2017 (incorporated by reference to Exhibit 3.1 to Form 8-K filed May 2, 2017).
3.8	Amendment No. 2 to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC, dated effective as of November 6, 2019 (incorporated by reference to Exhibit 3.12 to Form 10-Q filed November 8, 2019).
3.9	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.10	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.11	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit A to Exhibit 3.1 to Form 8-K filed October 1, 2020).
4.2	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 4.2 to Form 10-K filed February 28, 2020).

4.3	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 14, 2000).
4.4	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.6	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.7	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.8	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.9	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.10	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.11	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.12	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.13	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.14	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.15	Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 24, 2011).

4.16	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.17	Twenty-Third Supplemental Indenture, dated as of August 13, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 13, 2012).
4.18	Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.19	Twenty-Fifth Supplemental Indenture, dated as of February 12, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.20	Twenty-Sixth Supplemental Indenture, dated as of October 14, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.21	Twenty-Seventh Supplemental Indenture, dated as of May 7, 2015, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.22	Twenty-Eighth Supplemental Indenture, dated as of April 13, 2016, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.23	Twenty-Ninth Supplemental Indenture, dated as of August 16, 2017, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.24	Thirtieth Supplemental Indenture, dated as of February 15, 2018, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.25	Thirty-First Supplemental Indenture, dated as of February 15, 2018, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 15, 2018).
4.26	Thirty-Second Supplemental Indenture, dated as of October 11, 2018, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.27	Thirty-Third Supplemental Indenture, dated as of July 8, 2019, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed July 8, 2019).
4.28	Thirty-Fourth Supplemental Indenture, dated as of January 15, 2020, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 15, 2020).

4.29	Thirty-Fifth Supplemental Indenture, dated as of August 7, 2020, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 7, 2020).
4.30	Thirty-Sixth Supplemental Indenture, dated as of September 15, 2021, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Wells Fargo Bank, National Association, as Original Trustee, and U.S. Bank National Association, as Series Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 15, 2021).
4.31	Form of Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.32	Form of Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.33	Form of Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.34	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.35	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.36	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit E to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.37	Form of Global Note representing $285.8 million principal amount of Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.38	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.39	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.40	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.41	Form of Global Note representing $650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.42	Form of Global Note representing $600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.43	Form of Global Note representing $750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.44	Form of Global Note representing $1.1 billion principal amount of 4.45% Senior Notes due 2043 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 13, 2012).

4.45	Form of Global Note representing $1.25 billion principal amount of 3.35% Senior Notes due 2023 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.46	Form of Global Note representing $1.0 billion principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.47	Form of Global Note representing $850.0 million principal amount of 3.90% Senior Notes due 2024 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.48	Form of Global Note representing $1.15 billion principal amount of 5.10% Senior Notes due 2045 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.49	Form of Global Note representing $1.15 billion principal amount of 3.75% Senior Notes due 2025 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.50	Form of Global Note representing $400.0 million principal amount of 4.95% Senior Notes due 2054 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.51	Form of Global Note representing $400.0 million principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.52	Form of Global Note representing $875.0 million principal amount of 3.70% Senior Notes due 2026 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.53	Form of Global Note representing $875.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.54	Form of Global Note representing $575.0 million principal amount of 2.85% Senior Notes due 2021 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.55	Form of Global Note representing $575.0 million principal amount of 3.95% Senior Notes due 2027 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.56	Form of Global Note representing $100.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.57	Form of Global Note representing $700 million principal amount of Junior Subordinated Notes D due 2077 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.58	Form of Global Note representing $1.0 billion principal amount of Junior Subordinated Notes E due 2077 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.59	Form of Global Note representing $750.0 million principal amount of 2.80% Senior Notes due 2021 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.60	Form of Global Note representing $1.25 billion principal amount of 4.25% Senior Notes due 2048 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.61	Form of Global Note representing $700 million principal amount of Junior Subordinated Notes F due 2078 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed February 15, 2018).

4.62	Form of Global Note representing $750.0 million principal amount of 3.50% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.63	Form of Global Note representing $1,000.0 million principal amount of 4.15% Senior Notes due 2028 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.64	Form of Global Note representing $1,250.0 million principal amount of 4.80% Senior Notes due 2049 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.65	Form of Global Note representing $1,250.0 million principal amount of 3.125% Senior Notes due 2029 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed July 8, 2019).
4.66	Form of Global Note representing $1,250.0 million principal amount of 4.200% Senior Notes due 2050 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed July 8, 2019).
4.67	Form of Global Note representing $1,000.0 million principal amount of 2.800% Senior Notes due 2030 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed January 15, 2020).
4.68	Form of Global Note representing $1,000.0 million principal amount of 3.700% Senior Notes due 2051 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed January 15, 2020).
4.69	Form of Global Note representing $1,000.0 million principal amount of 3.950% Senior Notes due 2060 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed January 15, 2020).
4.70	Form of Global Note representing $250.0 million principal amount of 2.800% Senior Notes due 2030 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed January 15, 2020).
4.71	Form of Global Note representing $1,000.0 million principal amount of 3.200% Senior Notes due 2052 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed August 7, 2020).
4.72	Form of Global Note representing $1,000.0 million principal amount of 3.300% Senior Notes due 2053 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed September 15, 2021).
4.73	Replacement Capital Covenant, dated October 27, 2009, executed by Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
4.74	Amendment to Replacement Capital Covenants, dated May 6, 2015, executed by Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.59 to Form 10-Q filed May 8, 2015).
4.75	Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.76	Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).

4.77	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).
4.78	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.79	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.80	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed March 1, 2010).
4.81	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.82	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.83	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.84	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.85	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed March 1, 2010).
4.86	Registration Rights Agreement, dated as of March 5, 2020, between Enterprise Products Partners L.P. and Skyline North Americas, Inc. (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 5, 2020).
4.87	Equity Distribution Agreement, dated June 24, 2020, by and among Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC, Skyline North Americas, Inc. and Morgan Stanley & Co. LLC. (incorporated by reference to Exhibit 1.1 to Form 8-K filed June 25, 2020).
4.88	Specimen Unit Certificate for the Series A Cumulative Convertible Preferred Units, (incorporated by reference to Exhibit B to Exhibit 3.1 to Form 8-K filed October 1, 2020).

4.89	Registration Rights Agreement, dated as of September 30, 2020, by and among Enterprise Products Partners L.P. and the Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 1, 2020).
10.1	364-Day Revolving Credit Agreement, dated as of September 7, 2021, by and among Enterprise Products Operating LLC, as Borrower, the Lenders party thereto, Citibank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, JPMorgan Chase Bank, N.A., Mizuho Bank, Ltd., MUFG Bank, Ltd. and Truist Bank, as Co-Syndication Agents, and Barclays Bank PLC, Royal Bank of Canada, Sumitomo Mitsui Banking Corporation, The Bank of Nova Scotia, Houston Branch, and The Toronto-Dominion Bank, New York Branch, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 7, 2021).
10.2	Guaranty Agreement, dated as of September 7, 2021, by Enterprise Products Partners L.P. in favor of Citibank, N.A., as administrative agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 7, 2021).
10.3	Revolving Credit Agreement, dated as of September 7, 2021, by and among Enterprise Products Operating LLC, as Borrower, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, Citibank, N.A., JPMorgan Chase Bank, N.A., Mizuho Bank, Ltd., MUFG Bank, Ltd. and Truist Bank, as Co-Syndication Agents, and Barclays Bank PLC, Royal Bank of Canada, Sumitomo Mitsui Banking Corporation, The Bank of Nova Scotia, Houston Branch, and The Toronto-Dominion Bank, New York Branch, as Co-Documentation Agents (incorporated by reference to Exhibit 10.3 to Form 8-K filed September 7, 2021).
10.4	Guaranty Agreement, dated as of September 7, 2021, by Enterprise Products Partners L.P. in favor of Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.4 to Form 8-K filed September 7, 2021).
22.1#	List of Issuers of Debt Securities Guaranteed by Enterprise Products Partners L.P. and Associated Securities at September 30, 2021.
31.1#	Sarbanes-Oxley Section 302 certification of A. James Teague for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2021.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2021.
32.1#	Sarbanes-Oxley Section 906 certification of A. James Teague for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2021.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2021.
101#	Interactive data files pursuant to Rule 405 of Regulation S-T formatted in iXBRL (Inline Extensible Business Reporting Language) in this Form 10-Q include the: (i) Unaudited Condensed Consolidated Balance Sheets, (ii) Unaudited Condensed Statements of Consolidated Operations, (iii) Unaudited Condensed Statements of Consolidated Comprehensive Income, (iv) Unaudited Condensed Statements of Consolidated Cash Flows, (v) Unaudited Condensed Statements of Consolidated Equity and (vi) Notes to the Unaudited Condensed Consolidated Financial Statements.
104#	Cover Page Interactive Data File (embedded within the iXBRL document).

*	With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Enterprise GP Holdings L.P, TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-10403 and 1-13603, respectively.
***	Identifies management contract and compensatory plan arrangements.
#	Filed with this report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on November 8, 2021.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By:	Enterprise Products Holdings LLC, as General Partner
By:	*/s/ R. Daniel Boss*
Name:	R. Daniel Boss
Title:	Executive Vice President – Accounting, Risk Control and Information Technology of the General Partner

Exhibit 22.1

List of Issuers of Debt Securities Guaranteed by Enterprise Products Partners L.P. and Associated Securities at September 30, 2021.

In compliance with Item 601(b)(22) of Regulation S-K, the following is a list of publicly traded debt securities issued by Enterprise Products Operating LLC (the “Subsidiary Issuer”) and guaranteed by Enterprise Products Partners L.P. (the “Parent Guarantor”) (dollars in millions):

Guaranteed Securities	Amounts Outstanding at September 30, 2021
Senior Notes VV, 3.50% fixed-rate, due February 2022	$ 750.0
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0
Senior Notes HH, 3.35% fixed-rate, due March 2023	1,250.0
Senior Notes JJ, 3.90% fixed-rate, due February 2024	850.0
Senior Notes MM, 3.75% fixed-rate, due February 2025	1,150.0
Senior Notes PP, 3.70% fixed-rate, due February 2026	875.0
Senior Notes SS, 3.95% fixed-rate, due February 2027	575.0
Senior Notes WW, 4.15% fixed-rate, due October 2028	1,000.0
Senior Notes YY, 3.125% fixed-rate, due July 2029	1,250.0
Senior Notes AAA, 2.80% fixed-rate, due January 2030	1,250.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0
Senior Notes II, 4.85% fixed-rate, due March 2044	1,400.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0
Senior Notes QQ, 4.90% fixed-rate, due May 2046	975.0
Senior Notes UU, 4.25% fixed-rate, due February 2048	1,250.0
Senior Notes XX, 4.80% fixed-rate, due February 2049	1,250.0
Senior Notes ZZ, 4.20% fixed-rate, due January 2050	1,250.0
Senior Notes BBB, 3.70% fixed-rate, due January 2051	1,000.0
Senior Notes DDD, 3.20% fixed-rate, due February 2052	1,000.0
Senior Notes EEE, 3.30% fixed-rate, due February 2053	1,000.0
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0
Senior Notes CCC, 3.95% fixed rate, due January 2060	1,000.0
Junior Subordinated Notes C, variable-rate, due June 2067	232.2
Junior Subordinated Notes D, fixed/variable-rate, due August 2077	700.0
Junior Subordinated Notes E, fixed/variable-rate, due August 2077	1,000.0
Junior Subordinated Notes F, fixed/variable-rate, due February 2078	700.0

EXHIBIT 31.1

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, A. James Teague, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P;

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

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

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

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2021

/s/ A. James Teague

Name: A. James Teague
Title: Co-Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 31.2

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, W. Randall Fowler, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

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

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

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

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2021

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Co-Chief Executive Officer and Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF A. JAMES TEAGUE, CO-CHIEF EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS HOLDINGS LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the quarterly period ended September 30, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, A. James Teague, Co-Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

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

Date: November 8, 2021

/s/ A. James Teague

Name: A. James Teague
Title: Co-Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CO-CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS HOLDINGS LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the quarterly period ended September 30, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, W. Randall Fowler, Co-Chief Executive Officer and Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

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

Date: November 8, 2021

/s/ W. Randall Fowler

Name:	W. Randall Fowler
Title:	Co-Chief Executive Officer and Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.