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 March 31, 2024

or

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

Commission File Number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**76-0582150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

333 Clay Street, Suite 1600
Houston, Texas 77002
(Address of principal executive offices) (Zip code)
(713) 646-4100
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units	PAA	Nasdaq

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 the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

As of May 1, 2024, there were 701,071,031 Common Units outstanding.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except unit data)

	March 31, 2024	December 31, 2023
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 331	$ 450
Trade accounts receivable and other receivables, net	4,040	3,760
Inventory	453	548
Other current assets	177	155
Total current assets	5,001	4,913
PROPERTY AND EQUIPMENT	21,162	21,143
Accumulated depreciation	(5,491)	(5,361)
Property and equipment, net	15,671	15,782
OTHER ASSETS		
Investments in unconsolidated entities	2,878	2,820
Intangible assets, net	1,807	1,875
Linefill	981	976
Long-term operating lease right-of-use assets, net	298	313
Long-term inventory	299	265
Other long-term assets, net	421	411
Total assets	$ 27,356	$ 27,355
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Trade accounts payable	$ 3,991	$ 3,844
Short-term debt	554	446
Other current liabilities	599	713
Total current liabilities	5,144	5,003
LONG-TERM LIABILITIES		
Senior notes, net	7,244	7,242
Other long-term debt, net	64	63
Long-term operating lease liabilities	261	274
Other long-term liabilities and deferred credits	997	1,041
Total long-term liabilities	8,566	8,620
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
PARTNERS' CAPITAL		
Series A preferred unitholders (71,090,468 and 71,090,468 units outstanding, respectively)	1,510	1,509
Series B preferred unitholders (800,000 and 800,000 units outstanding, respectively)	787	787
Common unitholders (701,071,031 and 701,008,749 units outstanding, respectively)	8,042	8,126
Total partners' capital excluding noncontrolling interests	10,339	10,422
Noncontrolling interests	3,307	3,310
Total partners' capital	13,646	13,732
Total liabilities and partners' capital	$ 27,356	$ 27,355

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
	(unaudited)	
REVENUES		
Product sales revenues	$ 11,546	$ 11,943
Services revenues	449	398
Total revenues	11,995	12,341
COSTS AND EXPENSES		
Purchases and related costs	10,917	11,323
Field operating costs	358	357
General and administrative expenses	96	86
Depreciation and amortization	254	256
(Gains)/losses on asset sales, net	—	(154)
Total costs and expenses	11,625	11,868
OPERATING INCOME	370	473
OTHER INCOME/(EXPENSE)		
Equity earnings in unconsolidated entities	95	89
Interest expense (net of capitalized interest of $2 and $2, respectively)	(95)	(98)
Other income/(expense), net	(5)	64
INCOME BEFORE TAX	365	528
Current income tax expense	(53)	(61)
Deferred income tax benefit	39	8
NET INCOME	351	475
Net income attributable to noncontrolling interests	(85)	(53)
NET INCOME ATTRIBUTABLE TO PAA	$ 266	$ 422
NET INCOME PER COMMON UNIT (NOTE 3):		
Net income allocated to common unitholders — Basic and Diluted	$ 203	$ 361
Basic and diluted weighted average common units outstanding	701	698
Basic and diluted net income per common unit	$ 0.29	$ 0.52

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
	(unaudited)	
Net income	$ 351	$ 475
Other comprehensive loss	(71)	(1)
Comprehensive income	280	474
Comprehensive income attributable to noncontrolling interests	(85)	(53)
Comprehensive income attributable to PAA	$ 195	$ 421

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)
(in millions)

	Derivative Instruments	Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2023	$ (81)	$ (755)	$ (836)
Reclassification adjustments	2	—	2
Unrealized gain on hedges	13	—	13
Currency translation adjustments	—	(86)	(86)
Total period activity	15	(86)	(71)
Balance at March 31, 2024	$ (66)	$ (841)	$ (907)

	Derivative Instruments	Translation Adjustments	Other	Total
		(unaudited)		
Balance at December 31, 2022	$ (107)	$ (846)	$ (1)	$ (954)
Reclassification adjustments	2	—	—	2
Unrealized loss on hedges	(5)	—	—	(5)
Currency translation adjustments	—	1	—	1
Other	—	—	1	1
Total period activity	(3)	1	1	(1)
Balance at March 31, 2023	$ (110)	$ (845)	$ —	$ (955)

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 351	$ 475
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	254	256
(Gains)/losses on asset sales, net	—	(154)
Deferred income tax benefit	(39)	(8)
Change in fair value of Preferred Distribution Rate Reset Option (Note 7)	—	(58)
Equity earnings in unconsolidated entities	(95)	(89)
Distributions on earnings from unconsolidated entities	132	108
Other	8	15
Changes in assets and liabilities, net of acquisitions	(192)	198
Net cash provided by operating activities	419	743
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(91)	—
Investments in unconsolidated entities	(3)	(4)
Additions to property, equipment and other	(157)	(122)
Cash paid for purchases of linefill	(13)	—
Proceeds from sales of assets	3	284
Net cash provided by/(used in) investing activities	(261)	158
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings under commercial paper program (Note 5)	107	—
Repayments of senior notes	—	(400)
Distributions paid to Series A preferred unitholders (Note 6)	(44)	(37)
Distributions paid to Series B preferred unitholders (Note 6)	(20)	(18)
Distributions paid to common unitholders (Note 6)	(223)	(187)
Distributions paid to noncontrolling interests (Note 6)	(100)	(78)
Contributions from noncontrolling interests	12	—
Other financing activities	(5)	(56)
Net cash used in financing activities	(273)	(776)
Effect of translation adjustment	(4)	—
Net increase/(decrease) in cash and cash equivalents and restricted cash	(119)	125
Cash and cash equivalents and restricted cash, beginning of period	450	401
Cash and cash equivalents and restricted cash, end of period	$ 331	$ 526
Cash paid/(received) for:		
Interest, net of amounts capitalized	$ 64	$ 65
Income taxes, net of amounts refunded	$ 86	$ (18)

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(in millions)

	Limited Partners			Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Preferred Unitholders		Common Unitholders			
	Series A	Series B				
	(unaudited)					
Balance at December 31, 2023	$ 1,509	$ 787	$ 8,126	$ 10,422	$ 3,310	$ 13,732
Net income	44	19	203	266	85	351
Distributions (Note 6)	(44)	(19)	(223)	(286)	(100)	(386)
Other comprehensive loss	—	—	(71)	(71)	—	(71)
Contributions from noncontrolling interests	—	—	—	—	12	12
Other	1	—	7	8	—	8
Balance at March 31, 2024	$ 1,510	$ 787	$ 8,042	$ 10,339	$ 3,307	$ 13,646

	Limited Partners			Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Preferred Unitholders		Common Unitholders			
	Series A	Series B				
	(unaudited)					
Balance at December 31, 2022	$ 1,505	$ 787	$ 7,765	$ 10,057	$ 3,268	$ 13,325
Net income	42	18	362	422	53	475
Distributions	(42)	(18)	(187)	(247)	(78)	(325)
Other comprehensive loss	—	—	(1)	(1)	—	(1)
Other	1	—	11	12	(3)	9
Balance at March 31, 2023	$ 1,506	$ 787	$ 7,950	$ 10,243	$ 3,240	$ 13,483

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

Note 1—Organization and Basis of Consolidation and Presentation

Organization

Plains All American Pipeline, L.P. ("PAA") is a Delaware limited partnership formed in 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-Q and unless the context indicates otherwise, the terms "Partnership," "we," "us," "our," "ours" and similar terms refer to PAA and its subsidiaries.

Our business model integrates large-scale supply aggregation capabilities with the ownership and operation of critical midstream infrastructure systems that connect major producing regions to key demand centers and export terminals. As one of the largest midstream service providers in North America, we own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and natural gas liquids ("NGL") producing basins (including the Permian Basin) and transportation corridors and at major market hubs in the United States and Canada. Our assets and the services we provide are primarily focused on and conducted through two operating segments: Crude Oil and NGL. See Note 10 for further discussion of our operating segments.

Our non-economic general partner interest is held by PAA GP LLC ("PAA GP"), a Delaware limited liability company, whose sole member is Plains AAP, L.P. ("AAP"), a Delaware limited partnership. In addition to its ownership of PAA GP, as of March 31, 2024, AAP also owned a limited partner interest in us through its ownership of approximately 232.7 million of our common units (approximately 30% of our total outstanding common units and Series A preferred units combined). Plains All American GP LLC ("GP LLC"), a Delaware limited liability company, is AAP's general partner. Plains GP Holdings, L.P. ("PAGP") is the sole and managing member of GP LLC, and, at March 31, 2024, owned an approximate 85% limited partner interest in AAP. PAA GP Holdings LLC ("PAGP GP") is the general partner of PAGP.

As the sole member of GP LLC, PAGP has responsibility for conducting our business and managing our operations; however, the board of directors of PAGP GP has ultimate responsibility for managing the business and affairs of PAGP, AAP and us. GP LLC employs our domestic officers and personnel; our Canadian officers and personnel are employed by our subsidiary, Plains Midstream Canada ULC.

References to our "general partner," as the context requires, include any or all of PAGP GP, PAGP, GP LLC, AAP and PAA GP.

Definitions

Additional defined terms are used in this Form 10-Q and shall have the meanings indicated below:

AOCI	=	Accumulated other comprehensive income/(loss)
ASC	=	Accounting Standards Codification
ASU	=	Accounting Standards Update
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
CODM	=	Chief Operating Decision Maker
EBITDA	=	Earnings before interest, taxes, depreciation and amortization
EPA	=	United States Environmental Protection Agency
FASB	=	Financial Accounting Standards Board
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	Intercontinental Exchange
ISDA	=	International Swaps and Derivatives Association
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MMbls	=	Million barrels
NGL	=	Natural gas liquids, including ethane, propane and butane
NYMEX	=	New York Mercantile Exchange
SEC	=	United States Securities and Exchange Commission
SOFR	=	Secured Overnight Financing Rate
TWh	=	Terawatt hour
USD	=	United States dollar
WTI	=	West Texas Intermediate

Basis of Consolidation and Presentation

The accompanying unaudited condensed consolidated interim financial statements and related notes thereto should be read in conjunction with our 2023 Annual Report on Form 10-K. The accompanying condensed consolidated financial statements include the accounts of PAA and all of its wholly owned subsidiaries and those entities that it controls. Investments in entities over which we have significant influence but not control are accounted for by the equity method. We apply proportionate consolidation for pipelines and other assets in which we own undivided joint interests. The financial statements have been prepared in accordance with the instructions for interim reporting as set forth by the SEC. The condensed consolidated balance sheet data as of December 31, 2023 was derived from audited financial statements, but does not include all disclosures required by GAAP. The results of operations for the three months ended March 31, 2024 should not be taken as indicative of results to be expected for the entire year. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany balances and transactions have been eliminated in consolidation.

Subsequent Events

Subsequent events have been evaluated through the financial statements issuance date and have been included in the following footnotes where applicable.

Recent Accounting Pronouncements and Disclosure Rules

Except as discussed in our 2023 Annual Report on Form 10-K, there have been no new accounting pronouncements that have become effective or have been issued during the three months ended March 31, 2024 that are of significance or potential significance to us.

In March 2024, the SEC adopted final rules (“climate disclosure rules”) requiring registrants to disclose, among other things, information about material climate-related risks and their impact on a registrant’s strategy, business model and outlook; information about material direct and indirect greenhouse gas emissions (Scope 1 and Scope 2), which are subject to assurance requirements; and the financial statement effects of severe weather events and other natural conditions. Such disclosure requirements will begin phasing in for annual periods beginning in 2025. In April 2024, the SEC stayed the climate disclosure rules pending resolution of legal challenges. We are currently evaluating the climate disclosure rules to determine the impact on our related disclosures.

Note 2—Revenues and Accounts Receivable

Revenue Recognition

We disaggregate our revenues by segment and type of activity. See Note 3 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for additional information regarding our types of revenues and policies for revenue recognition.

Revenues from Contracts with Customers. The following tables present our revenues from contracts with customers disaggregated by segment and type of activity (in millions):

	Three Months Ended March 31,	
	2024	2023
Crude Oil segment revenues from contracts with customers		
Sales	$ 11,185	$ 11,381
Transportation	300	250
Terminalling, Storage and Other	92	90
Total Crude Oil segment revenues from contracts with customers	$ 11,577	$ 11,721

	Three Months Ended March 31,	
	2024	2023
NGL segment revenues from contracts with customers		
Sales	$ 600	$ 660
Transportation	10	8
Terminalling, Storage and Other	21	28
Total NGL segment revenues from contracts with customers	$ 631	$ 696

Reconciliation to Total Revenues of Reportable Segments. The following disclosures only include information regarding revenues associated with consolidated entities; revenues from entities accounted for by the equity method are not included. The following tables present the reconciliation of our revenues from contracts with customers to total revenues of reportable segments and total revenues as disclosed in our Condensed Consolidated Statements of Operations (in millions):

Three Months Ended March 31, 2024	Crude Oil	NGL	Total
Revenues from contracts with customers	$ 11,577	$ 631	$ 12,208
Other revenues	5	(124)	(119)
Total revenues of reportable segments	$ 11,582	$ 507	$ 12,089
Intersegment revenues elimination			(94)
Total revenues			$ 11,995

Three Months Ended March 31, 2023	Crude Oil	NGL	Total
Revenues from contracts with customers	$ 11,721	$ 696	$ 12,417
Other revenues	37	(6)	31
Total revenues of reportable segments	$ 11,758	$ 690	$ 12,448
Intersegment revenues elimination			(107)
Total revenues			$ 12,341

Minimum Volume Commitments. We have certain agreements that require counterparties to transport or throughput a minimum volume over an agreed upon period. The following table presents counterparty deficiencies associated with contracts with customers and buy/sell arrangements that include minimum volume commitments for which we had remaining performance obligations and the customers still had the ability to meet their obligations (in millions):

Counterparty Deficiencies	Financial Statement Classification	March 31, 2024	December 31, 2023
Billed and collected	Other current liabilities	$ 60	$ 77

Contract Balances. Our contract balances consist of amounts received associated with services or sales for which we have not yet completed the related performance obligation. The following table presents the changes in the liability balance associated with contracts with customers (in millions):

	Contract Liabilities
Balance at December 31, 2023	$ 228
Amounts recognized as revenue	(20)
Additions	17
Other	(5)
Balance at March 31, 2024	$ 220

Remaining Performance Obligations. The information below includes the amount of consideration allocated to partially and wholly unsatisfied remaining performance obligations under contracts that existed as of the end of the periods and the timing of revenue recognition of those remaining performance obligations. Certain contracts meet the requirements for the presentation as remaining performance obligations. These contracts include a fixed minimum level of service, typically a set volume of service, and do not contain any variability other than expected timing within a limited range. The following table presents the amount of consideration associated with remaining performance obligations for the population of contracts with external customers meeting the presentation requirements as of March 31, 2024 (in millions):

	Remainder of 2024	2025	2026	2027	2028	2029 and Thereafter
Pipeline revenues supported by minimum volume commitments and capacity agreements [1]	$ 299	$ 354	$ 163	$ 109	$ 80	$ 194
Terminalling, storage and other agreement revenues	182	169	132	118	100	708
Total	$ 481	$ 523	$ 295	$ 227	$ 180	$ 902

(1) Calculated as volumes committed under contracts multiplied by the current applicable tariff rate.

The presentation above does not include (i) expected revenues from legacy shippers not underpinned by minimum volume commitments, including pipelines where there are no or limited alternative pipeline transportation options, (ii) intersegment revenues and (iii) the amount of consideration associated with certain income generating contracts, which include a fixed minimum level of service, that are either not within the scope of ASC 606 or do not meet the requirements for presentation as remaining performance obligations. The following are examples of contracts that are not included in the table above because they are not within the scope of ASC 606 or do not meet the requirements for presentation:

- Minimum volume commitments on certain of our joint venture pipeline systems;
- Acreage dedications;
- Buy/sell arrangements with future committed volumes;
- Short-term contracts and those with variable consideration, due to the election of practical expedients;
- Contracts within the scope of ASC Topic 842, *Leases*; and
- Contracts within the scope of ASC Topic 815, *Derivatives and Hedging*.

Trade Accounts Receivable and Other Receivables, Net

At March 31, 2024 and December 31, 2023, substantially all of our trade accounts receivable were less than 30 days past their invoice date. Our expected credit losses are immaterial. Although we consider our credit procedures to be adequate to mitigate any significant credit losses, the actual amount of current and future credit losses could vary significantly from estimated amounts.

The following is a reconciliation of trade accounts receivable from revenues from contracts with customers to total Trade accounts receivable and other receivables, net as presented on our Condensed Consolidated Balance Sheets (in millions):

	March 31, 2024	December 31, 2023
Trade accounts receivable arising from revenues from contracts with customers	$ 4,347	$ 3,999
Other trade accounts receivables and other receivables [1]	8,284	7,535
Impact due to contractual rights of offset with counterparties	(8,591)	(7,774)
Trade accounts receivable and other receivables, net	$ 4,040	$ 3,760

(1) The balance is comprised primarily of accounts receivable associated with buy/sell arrangements that are not within the scope of ASC 606.

Note 3—Net Income Per Common Unit

We calculate basic and diluted net income per common unit by dividing net income attributable to PAA (after deducting amounts allocated to the preferred unitholders and participating securities) by the basic and diluted weighted average number of common units outstanding during the period.

The diluted weighted average number of common units is computed based on the weighted average number of common units plus the effect of potentially dilutive securities outstanding during the period, which include (i) our Series A preferred units and (ii) our equity-indexed compensation plan awards. See Note 11 and Note 17 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for a discussion of our Series A preferred units and equity-indexed compensation plan awards. When applying the if-converted method prescribed by FASB guidance, the possible conversion of approximately 71 million Series A preferred units, on a weighted-average basis, were excluded from the calculation of diluted net income per common unit for each of the three months ended March 31, 2024 and 2023 as the effect was antidilutive. Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered potentially dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive during the period are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

The following table sets forth the computation of basic and diluted net income per common unit (in millions, except per unit data):

	Three Months Ended March 31,	
	2024	2023
Basic and Diluted Net Income per Common Unit		
Net income attributable to PAA	$ 266	$ 422
Distributions to Series A preferred unitholders	(44)	(42)
Distributions to Series B preferred unitholders	(19)	(18)
Amounts allocated to participating securities	(1)	(2)
Other	1	1
Net income allocated to common unitholders [(1)]	$ 203	$ 361
Basic and diluted weighted average common units outstanding	701	698
Basic and diluted net income per common unit	$ 0.29	$ 0.52

(1) We calculate net income allocated to common unitholders based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings (i.e., undistributed loss), if any, are allocated to the common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.

Note 4—Inventory, Linefill and Long-term Inventory

Inventory, linefill and long-term inventory consisted of the following (barrels in thousands and carrying value in millions):

	March 31, 2024				December 31, 2023			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]
Inventory								
Crude oil	5,578	barrels	$ 374	$ 67.05	5,877	barrels	$ 383	$ 65.17
NGL	2,604	barrels	68	$ 26.11	5,957	barrels	154	$ 25.85
Other	N/A		11	N/A	N/A		11	N/A
Inventory subtotal			453				548	
Linefill								
Crude oil	15,541	barrels	914	$ 58.81	15,409	barrels	909	$ 58.99
NGL	2,242	barrels	67	$ 29.88	2,168	barrels	67	$ 30.90
Linefill subtotal			981				976	
Long-term inventory								
Crude oil	3,279	barrels	262	$ 79.90	3,256	barrels	232	$ 71.25
NGL	1,325	barrels	37	$ 27.92	1,326	barrels	33	$ 24.89
Long-term inventory subtotal			299				265	
Total			$ 1,733				$ 1,789	

(1) Price per unit of measure is comprised of a weighted average associated with various grades, qualities and locations. Accordingly, these prices may not coincide with any published benchmarks for such products.

Note 5—Debt

Debt consisted of the following (in millions):

	March 31, 2024	December 31, 2023
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 5.7% and 5.8%, respectively [1]	$ 540	$ 433
Other	14	13
Total short-term debt	554	446
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $39 and $41, respectively [2]	7,244	7,242
Other	64	63
Total long-term debt	7,308	7,305
Total debt [3]	$ 7,862	$ 7,751

(1) We classified these commercial paper notes as short-term as of March 31, 2024 and December 31, 2023, as these notes were primarily designated as working capital borrowings, were required to be repaid within one year and were primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

(2) As of March 31, 2024 and December 31, 2023, we classified our $750 million, 3.60% senior notes due November 2024 as long-term based on our ability and intent to refinance these notes on a long-term basis.

(3) Our fixed-rate senior notes had a face value of approximately $7.3 billion as of March 31, 2024 and December 31, 2023. We estimated the aggregate fair value of these notes as of March 31, 2024 and December 31, 2023 to be approximately $6.9 billion. Our fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near the end of the reporting period. We estimate that the carrying value of outstanding borrowings under our commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes and commercial paper program are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the three months ended March 31, 2024 and 2023 were approximately $9.1 billion and $1.5 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $9.0 billion and $1.5 billion for the three months ended March 31, 2024 and 2023, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

Letters of Credit

In connection with our merchant activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase and transportation of crude oil and NGL. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At March 31, 2024 and December 31, 2023, we had outstanding letters of credit of $161 million and $205 million, respectively.

Note 6—Partners' Capital and Distributions

Units Outstanding

The following tables present the activity for our preferred and common units:

	Limited Partners		
	Series A Preferred Units	Series B Preferred Units	Common Units
Outstanding at December 31, 2023	71,090,468	800,000	701,008,749
Issuances of common units under equity-indexed compensation plans	—	—	62,282
Outstanding at March 31, 2024	71,090,468	800,000	701,071,031

	Limited Partners		
	Series A Preferred Units	Series B Preferred Units	Common Units
Outstanding at December 31, 2022	71,090,468	800,000	698,354,498
Issuances of common units under equity-indexed compensation plans	—	—	35,508
Outstanding at March 31, 2023	71,090,468	800,000	698,390,006

Distributions

Series A Preferred Unit Distributions. Distributions on the Series A preferred units accumulate and are payable quarterly within 45 days following the end of each quarter. See Note 11 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for additional information regarding Series A preferred unit distributions. The following table details distributions to our Series A preferred unitholders paid during or pertaining to the first three months of 2024 (in millions, except per unit data):

	Series A Preferred Unitholders	
Distribution Payment Date	Cash Distribution	Distribution per Unit
May 15, 2024 [1]	$ 44	$ 0.615
February 14, 2024	$ 44	$ 0.615

(1) Payable to unitholders of record at the close of business on May 1, 2024 for the period from January 1, 2024 through March 31, 2024. At March 31, 2024, such amount was accrued as distributions payable in "Other current liabilities" on our Condensed Consolidated Balance Sheet.

Series B Preferred Unit Distributions. Distributions on the Series B preferred units accumulate and are payable quarterly in arrears on the 15th day of February, May, August and November. See Note 11 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for additional information regarding Series B preferred unit distributions. The following table details distributions paid or to be paid to our Series B preferred unitholders (in millions, except per unit data):

	Series B Preferred Unitholders	
Distribution Payment Date	Cash Distribution	Distribution per Unit
May 15, 2024 [1]	$ 19	$ 24.20
February 15, 2024	$ 20	$ 24.92

(1) Payable to unitholders of record at the close of business on May 1, 2024 for the period from February 15, 2024 through May 14, 2024. At March 31, 2024, approximately $10 million of accrued distributions payable to our Series B preferred unitholders was included in "Other current liabilities" on our Condensed Consolidated Balance Sheet.

Common Unit Distributions. The following table details distributions to our common unitholders paid during or pertaining to the first three months of 2024 (in millions, except per unit data):

	Distributions			
	Common Unitholders			
Distribution Payment Date	Public	AAP	Total Cash Distribution	Distribution per Common Unit
May 15, 2024 [1]	$ 149	$ 74	$ 223	$ 0.3175
February 14, 2024	$ 149	$ 74	$ 223	$ 0.3175

(1) Payable to unitholders of record at the close of business on May 1, 2024 for the period from January 1, 2024 through March 31, 2024.

Noncontrolling Interests in Subsidiaries

As of March 31, 2024, noncontrolling interests in our subsidiaries consisted of (i) a 35% interest in Plains Oryx Permian Basin LLC (the "Permian JV"), (ii) a 30% interest in Cactus II Pipeline LLC ("Cactus II") and (iii) a 33% interest in Red River Pipeline Company LLC ("Red River").

Distributions to Noncontrolling Interests

The following table details distributions paid to noncontrolling interests during the periods presented (in millions):

	Three Months Ended March 31,	
	2024	2023
Permian JV	$ 74	$ 58
Cactus II	20	14
Red River	6	6
	$ 100	$ 78

Note 7—Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. We use various derivative instruments to optimize our profits while managing our exposure to commodity price risk and interest rate risk. Our commodity price risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our derivative positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate risk management policies and procedures are designed to monitor our derivative positions and ensure that those positions are consistent with our objectives and approved strategies. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on changes in commodity prices or interest rates. When we apply hedge accounting, our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. At the inception of the hedging relationship, we assess whether the derivatives employed are highly effective in offsetting changes in cash flows of anticipated hedged transactions. Throughout the hedging relationship, retrospective and prospective hedge effectiveness is assessed on a qualitative basis.

We record all open derivatives on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives designated as cash flow hedges, changes in fair value are deferred in AOCI and recognized in earnings in the periods during which the underlying hedged transactions are recognized in earnings. Derivatives that are not designated in a hedging relationship for accounting purposes are recognized in earnings each period. Cash settlements associated with our derivative activities are classified within the same category as the related hedged item in our Condensed Consolidated Statements of Cash Flows.

Our financial derivatives, used for hedging risk, are governed through ISDA master agreements and clearing brokerage agreements. These agreements include stipulations regarding the right of set off in the event that we or our counterparty default on performance obligations. If a default were to occur, both parties have the right to net amounts payable and receivable into a single net settlement between parties.

At March 31, 2024 and December 31, 2023, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings. Although we may be required to post margin on our exchange-traded derivatives transacted through a clearing brokerage account, as described below, we do not require our non-cleared derivative counterparties to post collateral with us.

Commodity Price Risk Hedging

Our core business activities involve certain commodity price-related risks that we manage in various ways, including through the use of derivative instruments. Our policy is to (i) only purchase inventory for which we have a sales market, (ii) structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold material physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities are described below.

In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of March 31, 2024, net derivative positions related to these activities included:

- A net long position of 5.6 million barrels associated with our crude oil purchases, which was unwound ratably during April 2024 to match monthly average pricing.
- A net short time spread position of 4.8 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through April 2025.
- A net crude oil basis spread position of 2.8 million barrels at multiple locations through November 2025. These derivatives allow us to lock in grade and location basis differentials.
- A net short position of 13.4 million barrels through March 2026 related to anticipated net sales of crude oil and NGL inventory.

We purchase natural gas for processing and operational needs. Additionally, we purchase NGL mix for fractionation and sell the resulting individual specification products (including ethane, propane, butane and condensate). In conjunction with these activities, we hedge the price risk associated with the purchase of the natural gas and the subsequent sale of the individual specification products. The following table summarizes our open derivative positions utilized to hedge the price risk associated with anticipated purchases and sales related to our natural gas processing and NGL fractionation activities as of March 31, 2024:

	Notional Volume (Short)/Long	Remaining Tenor
Natural gas purchases	68.5 Bcf	June 2025
Propane sales	(12.4) MMbls	June 2025
Butane sales	(2.1) MMbls	December 2024
Condensate sales	(2.8) MMbls	March 2025
Fuel gas requirements (1)	5.7 Bcf	December 2025
Power supply requirements (1)	2.5 TWh	December 2030

(1) Positions to hedge a portion of our power supply and fuel gas requirements at our Canadian natural gas processing and fractionation plants.

Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the normal purchases and normal sales scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings. We have determined that substantially all of our physical commodity contracts qualify for the normal purchases and normal sales scope exception.

Our commodity derivatives are not designated in a hedging relationship for accounting purposes; as such, changes in the fair value are reported in earnings. The following table summarizes the impact of our commodity derivatives recognized in earnings (in millions):

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
Product sales revenues	$ (173)	$ (1)
Field operating costs	(16)	(19)
Net gain/(loss) from commodity derivative activity	$ (189)	$ (20)

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through clearing brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. The following table provides the components of our net broker receivable/(payable) (in millions):

	March 31, 2024	December 31, 2023
Initial margin	$ 64	$ 77
Variation margin posted/(returned)	102	(65)
Letters of credit	(25)	(25)
Net broker receivable/(payable)	$ 141	$ (13)

The following table reflects the Condensed Consolidated Balance Sheet line items that include the fair values of our commodity derivative assets and liabilities and the effect of the collateral netting. Such amounts are presented on a gross basis, before the effects of counterparty netting. However, we have elected to present our commodity derivative assets and liabilities with the same counterparty on a net basis on our Condensed Consolidated Balance Sheet when the legal right of offset exists. Amounts in the table below are presented in millions.

	March 31, 2024				December 31, 2023			
	Commodity Derivatives		Effect of Collateral Netting	Net Carrying Value Presented on the Balance Sheet	Commodity Derivatives		Effect of Collateral Netting	Net Carrying Value Presented on the Balance Sheet
	Assets	Liabilities			Assets	Liabilities		
Derivative Assets								
Other current assets	$ 42	$ (106)	$ 141	$ 77	$ 153	$ (79)	$ (13)	$ 61
Other long-term assets, net	2	(1)	—	1	3	—	—	3
Derivative Liabilities								
Other current liabilities	2	(50)	—	(48)	1	(64)	—	(63)
Other long-term liabilities and deferred credits	—	(26)	—	(26)	1	(15)	—	(14)
Total	$ 46	$ (183)	$ 141	$ 4	$ 158	$ (158)	$ (13)	$ (13)

Interest Rate Risk Hedging

We use interest rate derivatives to hedge the benchmark interest rate associated with interest payments occurring as a result of debt issuances. The derivative instruments we use to manage this risk consist of forward starting interest rate swaps and treasury locks. These derivatives are designated as cash flow hedges. As such, changes in fair value are deferred in AOCI and are reclassified to interest expense as we incur the interest expense associated with the underlying debt.

The following table summarizes the terms of our outstanding interest rate derivatives as of March 31, 2024 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/15/2026	3.09%	Cash flow hedge
Anticipated interest payments	4 forward starting swaps (30-year)	$ 100	6/14/2024	0.74%	Cash flow hedge

As of March 31, 2024, there was a net loss of $66 million deferred in AOCI. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with interest expense accruals associated with underlying debt instruments. We estimate that substantially all of the remaining deferred loss will be reclassified to earnings through 2056 as the underlying hedged transactions impact earnings. A portion of these amounts is based on market prices as of March 31, 2024; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The following table summarizes the net unrealized gain/(loss) recognized in AOCI for derivatives (in millions):

	Three Months Ended March 31,	
	2024	2023
Interest rate derivatives, net	$ 13	$ (5)

At March 31, 2024, the net fair value of our interest rate hedges, which were included in “Other current assets” and “Other long-term assets, net” on our Condensed Consolidated Balance Sheet, totaled $55 million and $13 million, respectively. At December 31, 2023, the net fair value of these hedges totaled $51 million and $4 million, which were included in “Other current assets” and “Other long-term assets, net”, respectively.

Recurring Fair Value Measurements

Derivative Financial Assets and Liabilities

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis (in millions):

	Fair Value as of March 31, 2024			Fair Value as of December 31, 2023		
Recurring Fair Value Measures [1]	Level 1	Level 2	Total	Level 1	Level 2	Total
Commodity derivatives	$ (10)	$ (127)	$ (137)	$ 9	$ (9)	$ —
Interest rate derivatives	—	68	68	—	55	55
Total net derivative asset/(liability)	$ (10)	$ (59)	$ (69)	$ 9	$ 46	$ 55

(1) Derivative assets and liabilities are presented above on a net basis but do not include related cash margin deposits.

Level 1

Level 1 of the fair value hierarchy includes exchange-traded commodity derivatives and over-the-counter commodity contracts such as futures and swaps. The fair value of exchange-traded commodity derivatives and over-the-counter commodity contracts is based on unadjusted quoted prices in active markets.

Level 2

Level 2 of the fair value hierarchy includes exchange-cleared commodity derivatives and over-the-counter commodity and interest rate derivatives that are traded in observable markets with less volume and transaction frequency than active markets. In addition, it includes certain physical commodity contracts. The fair values of these derivatives are corroborated with market observable inputs.

Rollforward of Level 3 Net Asset/(Liability)

The Preferred Distribution Rate Reset Option was accounted for as an embedded derivative that was bifurcated from the related host contract and recorded at fair value. The Preferred Distribution Rate Reset Option was settled in January 2023 when we received notice that the Series A preferred unitholders elected the Preferred Distribution Rate Reset Option, which resulted in a gain of $58 million recognized in “Other income/(expense), net” in our Condensed Consolidated Statement of Operations for the three months ended March 31, 2023. See Note 12 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for additional information regarding the Preferred Distribution Rate Reset Option.

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for the Preferred Distribution Rate Reset Option embedded derivative, which was classified as Level 3 in the fair value hierarchy (in millions):

	Three Months Ended March 31, 2023
Beginning Balance	$ (189)
Net gains/(losses) for the period included in earnings	58
Settlements	131
Ending Balance	$ —
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	$ —

Note 8—Related Party Transactions

See Note 16 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for a complete discussion of related parties, including the determination of our related parties and nature of involvement with such related parties.

Promissory Notes with our General Partner

In March 2023, PAGP issued an unsecured promissory note to us with a face value of CAD$500 million (“related party note receivable”). Concurrently, we assigned PAGP our interest in an existing unsecured promissory note for the same face value amount due from a consolidated subsidiary (“related party note payable”). Both notes are due April 2027 and bear interest at a rate of 8.25% per annum, payable semi-annually.

Accrued and unpaid interest receivable/payable was $3 million and $10 million as of March 31, 2024 and December 31, 2023, respectively. Interest income/expense on the related party notes totaled $8 million and $3 million for the three months ended March 31, 2024 and 2023, respectively.

As of March 31, 2024 and December 31, 2023, our outstanding related party note receivable and related party note payable balances were as follows (in millions):

	March 31, 2024	December 31, 2023
Related party note receivable [1]	$ 369	$ 379
Related party note payable [1]	$ 369	$ 379

(1) We have elected to present our related party notes with the same counterparty on a net basis on our Condensed Consolidated Balance Sheet because there is a legal right to offset and we intend to offset with the counterparty.

Transactions with Other Related Parties

During the three months ended March 31, 2024 and 2023, we recognized sales and transportation revenues, purchased petroleum products and utilized transportation and storage services from related parties. These transactions were conducted at posted tariff rates or prices that we believe approximate market.

The impact to our Condensed Consolidated Statements of Operations from these transactions is included below (in millions):

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
Revenues from related parties	$ 11	$ 11
Purchases and related costs from related parties	$ 97	$ 99

Our receivable and payable amounts with these related parties as reflected on our Condensed Consolidated Balance Sheets were as follows (in millions):

	March 31, 2024	December 31, 2023
Trade accounts receivable and other receivables, net from related parties [1]	$ 46	$ 63
Trade accounts payable to related parties [1] [2]	$ 67	$ 72

(1) Includes amounts related to transportation and storage services and amounts owed to us or advanced to us related to investment capital projects of equity method investees where we serve as construction manager.

(2) We have agreements to store crude oil at facilities and transport crude oil or utilize capacity on pipelines that are owned by equity method investees. A portion of our commitment to transport is supported by crude oil buy/sell or other agreements with third parties with commensurate quantities.

Note 9—Commitments and Contingencies

Loss Contingencies — General

To the extent we are able to assess the likelihood of a negative outcome for a contingency, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue an undiscounted liability equal to the estimated amount. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then we accrue an undiscounted liability equal to the minimum amount in the range. In addition, we estimate legal fees that we expect to incur associated with loss contingencies and accrue those costs when they are material and probable of being incurred.

We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss.

Legal Proceedings — General

In the ordinary course of business, we are involved in various legal proceedings, including those arising from regulatory and environmental matters. In connection with determining the probability of loss associated with such legal proceedings and whether any potential losses associated therewith are estimable, we take into account what we believe to be all relevant known facts and circumstances, and what we believe to be reasonable assumptions regarding the application of those facts and circumstances to existing agreements, laws and regulations. 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 protect us from losses arising from current or future legal proceedings.

Accordingly, we can provide no assurance that the outcome of the various legal proceedings that we are currently involved in, or will become involved with in the future, will not, individually or in the aggregate, have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Environmental — General

We currently own or lease, and in the past have owned and leased, properties where hazardous liquids, including hydrocarbons, are or have been handled. These properties and the hazardous liquids or associated wastes disposed thereon may be subject to the U.S. federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, and the U.S. federal Resource Conservation and Recovery Act, as amended, as well as state and Canadian federal and provincial laws and regulations. Under such laws and regulations, we could be required to remove or remediate hazardous liquids or associated wastes (including wastes disposed of or released by prior owners or operators) and to clean up contaminated property (including contaminated groundwater). Assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified or insured.

Although we have made significant investments in our maintenance and integrity programs, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline, rail, storage and other facility operations. These releases can result from accidents or from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. We also may discover environmental impacts from past releases that were previously unidentified. Damages and liabilities associated with any such releases from our existing or future assets could be significant and could have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and the amounts can be reasonably estimated. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We do not discount our environmental remediation liabilities to present value. We also record environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. We record receivables for amounts we believe are recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

Environmental expenditures that pertain to current operations or to future revenues are expensed or capitalized consistent with our capitalization policy for property and equipment. Expenditures that result from the remediation of an existing condition caused by past operations and that do not contribute to current or future profitability are expensed.

At March 31, 2024, our estimated undiscounted reserve for environmental liabilities (excluding liabilities related to the Line 901 incident, as discussed further below) totaled $56 million, of which $11 million was classified as short-term and $45 million was classified as long-term. At December 31, 2023, our estimated undiscounted reserve for environmental liabilities (excluding liabilities related to the Line 901 incident) totaled $56 million, of which $10 million was classified as short-term and $46 million was classified as long-term. Such short-term liabilities are reflected in “Other current liabilities” and long-term liabilities are reflected in “Other long-term liabilities and deferred credits” on our Condensed Consolidated Balance Sheets. At both March 31, 2024 and December 31, 2023, we had recorded receivables (excluding receivables related to the Line 901 incident) totaling $4 million for amounts probable of recovery under insurance and from third parties under indemnification agreements, approximately $1 million of which for each period is reflected in “Other long-term assets, net” and the remainder is reflected in “Trade accounts receivable and other receivables, net” on our Condensed Consolidated Balance Sheets.

In some cases, the actual cash expenditures associated with these liabilities may not occur for three years or longer. Our estimates used in determining these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing or future legal claims giving rise to additional liabilities. Therefore, although we believe that the reserve is adequate, actual costs incurred (which may ultimately include costs for contingencies that are currently not reasonably estimable or costs for contingencies where the likelihood of loss is currently believed to be only reasonably possible or remote) may be in excess of the reserve and may potentially have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Specific Legal, Environmental or Regulatory Matters

Line 901 Incident. In May 2015, we experienced a crude oil release from our Las Flores to Gaviota Pipeline (Line 901) in Santa Barbara County, California. A portion of the released crude oil reached the Pacific Ocean at Refugio State Beach through a drainage culvert. Following the release, we shut down the pipeline and initiated our emergency response plan. A Unified Command, which included the United States Coast Guard, the EPA, the State of California Department of Fish and Wildlife (“CDFW”), the California Office of Spill Prevention and Response and the Santa Barbara Office of Emergency Management, was established for the response effort. Clean-up and remediation operations with respect to impacted shoreline and other areas has been determined by the Unified Command to be complete, and the Unified Command has been dissolved. Our estimate of the amount of oil spilled, based on relevant facts, data and information, and as set forth in the Consent Decree described below, is approximately 2,934 barrels; of this amount, we estimate that 598 barrels reached the Pacific Ocean.

As a result of the Line 901 incident, several governmental agencies and regulators initiated investigations into the Line 901 incident, various claims have been made against us and a number of lawsuits have been filed against us, the majority of which have been resolved. Set forth below is a brief summary of actions and matters that are currently pending or recently resolved.

As the "responsible party" for the Line 901 incident we are liable for various costs and for certain natural resource damages under the Oil Pollution Act. In this regard, following the Line 901 incident, we entered into a cooperative Natural Resource Damage Assessment ("NRDA") process with the federal and state agencies designated or authorized by law to act as trustees for the natural resources of the United States and the State of California (collectively, the "Trustees"). Additionally, various government agencies sought to collect civil fines and penalties under applicable state and federal regulations. On March 13, 2020, the United States and the People of the State of California filed a civil complaint against Plains All American Pipeline, L.P. and Plains Pipeline L.P. along with a pre-negotiated settlement agreement in the form of a Consent Decree (the "Consent Decree") that was signed by the United States Department of Justice, Environmental and Natural Resources Division, the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration, the EPA, CDFW, the California Department of Parks and Recreation, the California State Lands Commission, the California Department of Forestry and Fire Protection's Office of the State Fire Marshal, Central Coast Regional Water Quality Control Board, and Regents of the University of California. The Consent Decree was approved and entered by the Federal District Court for the Central District of California on October 14, 2020. Pursuant to the terms of the Consent Decree, Plains paid $24 million in civil penalties and $22.325 million as compensation for injuries to, destruction of, loss of, or loss of use of natural resources resulting from the Line 901 incident. The Consent Decree, which resolved all regulatory claims related to the incident, also contains requirements for implementing certain agreed-upon injunctive relief, as well as requirements for potentially restarting Line 901 and the Sisquoc to Pentland portion of Line 903. On October 13, 2022, Plains sold Line 901 and the Sisquoc to Pentland portion of Line 903 to Pacific Pipeline Company, an indirect wholly owned subsidiary of Exxon Mobil Corporation. As required by the terms of the Consent Decree, such purchaser assumed responsibility for compliance with the Consent Decree as it relates to the future ownership and operation of Line 901 and the Sisquoc to Pentland portion of Line 903.

Following an investigation and grand jury proceedings, in May of 2016, PAA was charged by a California state grand jury, pursuant to an indictment filed in California Superior Court, Santa Barbara County (the "May 2016 Indictment"), with alleged violations of California law in connection with the Line 901 incident. Fifteen charges from the May 2016 Indictment were the subject of a jury trial in California Superior Court in Santa Barbara County, and the jury returned a verdict on September 7, 2018, pursuant to which we were (i) found guilty on one felony discharge count and eight misdemeanor counts (which included one reporting count, one strict liability discharge count and six strict liability animal takings counts) and (ii) found not guilty on one strict liability animal takings count. The remaining counts were subsequently dismissed by the Court. On April 25, 2019, PAA was sentenced to pay fines and penalties in the aggregate amount of just under $3.35 million for the convictions covered by the September 2018 jury verdict (the "2019 Sentence"). The fines and penalties imposed in connection with the 2019 Sentence have been paid. In September 2021, the Superior Court concluded a series of hearings on the issue of whether there were any "direct victims" of the spill that are entitled to restitution under applicable criminal law. Through a series of final orders issued at the trial court level and without affecting any rights of the claimants under civil law, the Court dismissed the vast majority of the claims and ruled that the claimants were not entitled to restitution under applicable criminal laws. The Court did award an aggregate amount of less than $150,000 to a handful of claimants and we settled with approximately 40 claimants before the hearings for aggregate consideration that is not material. The prosecution and certain separately represented claimants have appealed the Court's rulings.

We also received several individual lawsuits and claims from companies, governmental agencies and individuals alleging damages arising out of the Line 901 incident. These lawsuits and claims generally seek restitution, compensatory and punitive damages, and/or injunctive relief. The majority of these lawsuits have been settled or dismissed by the court. In addition to the other lawsuits disclosed herein, the following lawsuits remain: (i) a lawsuit in California Superior Court in Santa Barbara County for lost revenue or profit asserted by a former oil producer that declared bankruptcy and shut in its offshore production platform following the Line 901 incident, which is currently scheduled for trial in July 2024; (ii) a lawsuit filed by the California State Land Commission in California Superior Court in Santa Barbara County seeking lost royalties following the shut-down of Line 901, as well as costs related to the decommissioning of such platform, which is currently scheduled for trial in October 2024, and (iii) lawsuits filed in California Superior Court in Santa Barbara County by various companies and individuals who provided labor, goods, or services associated with oil production activities they claim were disrupted following the Line 901 incident, which lawsuits have not yet been set for trial. We are vigorously defending these remaining lawsuits and believe we have strong defenses.

Furthermore, shortly following the Line 901 incident, we established a claims line and encouraged any parties that were damaged by the release to contact us to discuss their damage claims. We received a number of claims through the claims line and we have processed those claims and made payments as appropriate.

Additionally, a class action lawsuit was filed against us in United States District Court for the Central District of California in which the class plaintiffs seek a declaratory judgment that Plains' right-of-way agreements would not allow Plains to lay a new pipeline to replace Line 901 and/or the non-operating segment of Line 903 without paying additional compensation. The purchaser of Line 901 and the Sisquoc to Pentland portion of Line 903 has assumed liability for these claims with respect to its interest in such acquired pipelines and Plains has been dismissed from this portion of the lawsuit. In the same proceeding, a small subset of plaintiffs are also claiming damages to compensate them for trespass and the alleged diminished value of their properties due to the stigma of the oil spill. We are vigorously defending against these immaterial claims. This case is currently scheduled to go to trial in July 2024.

In a separate class action lawsuit that was pending in United States District Court for the Central District of California, the plaintiffs claimed two different classes of claimants were damaged by the release: (i) commercial fishermen who landed fish in certain specified fishing blocks in the waters off the coast of Southern California or persons or businesses who resold commercial seafood caught in those areas; and (ii) owners and lessees of residential beachfront properties, or properties with a private easement to a beach, where plaintiffs claim oil from the spill washed up. In 2022, in order to fully and finally resolve all claims and litigation for both classes, we reached an agreement to settle this case in exchange for a payment of $230 million (the "Class Action Settlement"). The Class Action Settlement was formally approved by the trial court on September 20, 2022, and we made the $230 million settlement payment on October 27, 2022 and the lawsuit was subsequently dismissed.

Plains formally submitted claims for reimbursement of the Class Action Settlement to our insurance carriers on November 7, 2022. To date, we have received payment of approximately $3.6 million from one insurer, which represents the final payment obligation of such insurer and brings the total amount collected from all insurers under such program to $275 million of the $500 million policy limits as of March 31, 2024. Insurers responsible for $185 million of the remaining $225 million of coverage have formally communicated a denial of coverage for the Class Action Settlement, generally alleging that some or all damages encompassed by the Class Action Settlement are not covered by their policies and that all or some portion of the $275 million for which Plains has already received insurance reimbursement does not properly exhaust the underlying policies that paid those sums. The insurer responsible for the final $40 million of coverage under such insurance program has not yet accepted nor denied coverage. We have initiated final and binding arbitration proceedings against all of the insurers responsible for the remaining $225 million of coverage with respect to which we have not received reimbursement. We believe that our claim for reimbursement from our insurers of the Class Action Settlement payment is strong and that our ultimate recovery of such amounts is probable. Our belief is based on: (i) our analysis of the terms of the underlying insurance policies as applied to the facts and circumstances that comprise our claim for reimbursement, (ii) our experience with the cost submissions and timely collection of claims for the $275 million collected to date for this incident under the same insurance program as the denied claims, including from some of the same insurers who are now denying claims, (iii) our extensive legal review and assessment of the insurer's claimed basis for denial of coverage, which review and assessment includes the advice of external legal counsel experienced in these type of matters and solidly supports our belief that our insurers are required to provide coverage based on the terms of the policies and the nature of our claims, and (iv) the financial strength of the insurance carriers as determined by an independent credit ratings agency. Various factors could impact the timing and amount of recovery of our insurance receivable, including future developments that adversely impact our assessment of the strength of our coverage claims, the outcome of any dispute resolution proceedings with respect to our coverage claims and the extent to which insurers may become insolvent in the future. An unfavorable resolution could have a material impact on our results of operations.

In connection with the foregoing, including the Class Action Settlement, we have made adjustments to our total estimated Line 901 costs and the portion of such costs that we believe are probable of recovery from insurance carriers, net of deductibles. Effective as of March 31, 2024, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $750 million, which includes actual and projected emergency response and clean-up costs, natural resource damage assessments, fines and penalties payable pursuant to the Consent Decree, certain third-party claims settlements (including the Class Action Settlement), and estimated costs associated with our remaining Line 901 lawsuits and claims as described above, as well as estimates for certain legal fees and statutory interest where applicable. We accrue such estimates of aggregate total costs to “Field operating costs” in our Condensed Consolidated Statements of Operations. This estimate considers our prior experience in environmental investigation and remediation matters and available data from, and in consultation with, our environmental and other specialists, as well as currently available facts and presently enacted laws and regulations. We have made assumptions for (i) the resolution of certain third-party claims and lawsuits, but excluding claims and lawsuits with respect to which losses are not probable and reasonably estimable, and excluding future claims and lawsuits and (ii) the nature, extent and cost of legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Line 901 incident. Our estimate does not include any lost revenue associated with the shutdown of Line 901 or 903 and does not include any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where we currently regard the likelihood of loss as being only reasonably possible or remote. We believe we have accrued adequate amounts for all probable and reasonably estimable costs; however, this estimate is subject to uncertainties associated with the assumptions that we have made. For example, with respect to potential losses that we regard as only reasonably possible or remote, we have made assumptions regarding the strength of our legal position based on our assessment of the relevant facts and applicable law and precedent; if our assumptions regarding such matters turn out to be inaccurate (i.e., we are found to be liable under circumstances where we regard the likelihood of loss as being only reasonably possible or remote), we could be responsible for significant costs and expenses that are not currently included in our estimates and accruals. In addition, for any potential losses that we regard as probable and for which we have accrued an estimate of the potential losses, our estimates regarding damages, legal fees, court costs and interest could turn out to be inaccurate and the actual losses we incur could be significantly higher than the amounts included in our estimates and accruals. Also, the amount of time it takes for us to resolve all of the current and future lawsuits and claims that relate to the Line 901 incident could turn out to be significantly longer than we have assumed, and as a result the costs we incur for legal services could be significantly higher than we have estimated. Accordingly, our assumptions and estimates may turn out to be inaccurate and our total costs could turn out to be materially higher; therefore, we can provide no assurance that we will not have to accrue significant additional costs in the future with respect to the Line 901 incident.

We did not recognize any costs, net of amounts probable of recovery from insurance carriers, during the three months ended March 31, 2024 and 2023. As of March 31, 2024, we had a remaining undiscounted gross liability of approximately $90 million related to the Line 901 incident, which aggregate amount is reflected in “Current liabilities” on our Condensed Consolidated Balance Sheet. As discussed above, we maintain insurance coverage, which is subject to certain exclusions and deductibles, in the event of such liabilities. As of March 31, 2024, our incurred costs for the Line 901 incident have exceeded our insurance coverage limit of $500 million related to our 2015 insurance program applicable to the Line 901 incident by $250 million. Through March 31, 2024, we had collected, subject to customary reservations, approximately $280 million out of the $505 million of release costs that we believe are probable of recovery from insurance carriers (including the 2015 insurance program and our directors and officers (D&O) insurance policies), net of deductibles. Therefore, as of March 31, 2024, we have recognized a long-term receivable of approximately $225 million for the portion of the release costs that we believe is probable of recovery from insurance, net of deductibles and amounts already collected. We anticipate that the process to enforce our coverage claims with respect to the Class Action Settlement will take time and, accordingly, have recognized such amount as a long-term asset in “Other assets” on our Condensed Consolidated Balance Sheet.

We have completed the required clean-up and remediation work as determined by the Unified Command and the Unified Command has been dissolved; however, we expect to make payments for additional legal, professional and regulatory costs during future periods. Taking into account the costs that we have included in our total estimate of costs for the Line 901 incident and considering what we regard as very strong defenses to the claims made in our remaining Line 901 lawsuits, we do not believe the ultimate resolution of such remaining lawsuits will have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Other Litigation Matters. On July 19, 2022 Hartree Natural Gas Storage, LLC ("Hartree") filed a lawsuit under seal in the Superior Court for the State of Delaware asserting claims against PAA Natural Gas Storage, L.P. and PAA arising out of a Membership Interest Purchase Agreement relating to the 2021 sale of the Pine Prairie Energy Center natural gas storage facility to Hartree. We believe the claims are without merit and that the outcome of the lawsuit will not have a material adverse effect on our financial condition, results of operations or cash flows. We intend to vigorously defend against the claims asserted in this lawsuit, which is currently scheduled for trial in May 2024.

Note 10—Segment Information

We manage our operations through two operating segments, which are also our reportable segments: Crude Oil and NGL. See Note 19 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for a summary of the types of products and services from which each segment derives its revenues. Our CODM (our Chief Executive Officer) evaluates segment performance based on measures including Segment Adjusted EBITDA (as defined below) and maintenance capital.

The measure of Segment Adjusted EBITDA forms the basis of our internal financial reporting and is the primary performance measure used by our CODM in assessing performance and allocating resources among our operating segments. We define Segment Adjusted EBITDA as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses, plus (d) our proportionate share of the depreciation and amortization expense (including write-downs related to cancelled projects and impairments) of unconsolidated entities, further adjusted (e) for certain selected items including (i) gains and losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are either related to investing activities (such as the purchase of linefill) or purchases of long-term inventory, and inventory valuation adjustments, as applicable, (ii) long-term inventory costing adjustments, (iii) charges for obligations that are expected to be settled with the issuance of equity instruments, (iv) amounts related to deficiencies associated with minimum volume commitments, net of the applicable amounts subsequently recognized into revenue and (v) other items that our CODM believes are integral to understanding our core segment operating performance and (f) to exclude the portion of all preceding items that is attributable to noncontrolling interests ("Segment amounts attributable to noncontrolling interests").

The following tables reflect certain financial data for each segment (in millions):

	Crude Oil	NGL	Intersegment Revenues Elimination	Total
Three Months Ended March 31, 2024				
Revenues [1]:				
Product sales	$ 11,176	$ 458	$ (88)	$ 11,546
Services	406	49	(6)	449
Total revenues	$ 11,582	$ 507	$ (94)	$ 11,995
Equity earnings in unconsolidated entities	$ 95	$ —		$ 95
Segment Adjusted EBITDA	$ 553	$ 159		$ 712
Maintenance capital expenditures	$ 46	$ 11		$ 57
Three Months Ended March 31, 2023				
Revenues [1]:				
Product sales	$ 11,409	$ 635	$ (101)	$ 11,943
Services	349	55	(6)	398
Total revenues	$ 11,758	$ 690	$ (107)	$ 12,341
Equity earnings in unconsolidated entities	$ 89	$ —		$ 89
Segment Adjusted EBITDA	$ 517	$ 192		$ 709
Maintenance capital expenditures	$ 32	$ 16		$ 48

(1) Segment revenues include intersegment amounts that are eliminated in Purchases and related costs. Intersegment activities are conducted at posted tariff rates where applicable, or otherwise at rates similar to those charged to third parties or rates that we believe approximate market at the time the agreement is executed or renegotiated.

Segment Adjusted EBITDA Reconciliation

The following table reconciles Segment Adjusted EBITDA to Net income attributable to PAA (in millions):

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
Segment Adjusted EBITDA	$ 712	$ 709
Adjustments: [1]		
Depreciation and amortization of unconsolidated entities [2]	(19)	(22)
Derivative activities and inventory valuation adjustments [3]	(159)	(92)
Long-term inventory costing adjustments [4]	33	(29)
Deficiencies under minimum volume commitments, net [5]	12	7
Equity-indexed compensation expense [6]	(9)	(10)
Foreign currency revaluation [7]	21	3
Segment amounts attributable to noncontrolling interests [8]	128	98
Depreciation and amortization	(254)	(256)
Gains/(losses) on asset sales, net	—	154
Interest expense, net	(95)	(98)
Other income/(expense), net	(5)	64
Income before tax	365	528
Income tax expense	(14)	(53)
Net income	351	475
Net income attributable to noncontrolling interests	(85)	(53)
Net income attributable to PAA	$ 266	$ 422

(1) Represents adjustments utilized by our CODM in the evaluation of segment results.

(2) Includes our proportionate share of the depreciation and amortization expense (including write-downs related to cancelled projects and impairments) of unconsolidated entities.

(3) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results, we identify differences in the timing of earnings from the derivative instruments and the underlying transactions and exclude the related gains and losses in determining Segment Adjusted EBITDA such that the earnings from the derivative instruments and the underlying transactions impact Segment Adjusted EBITDA in the same period. In addition, we exclude gains and losses on derivatives that are related to (i) investing activities, such as the purchase of linefill, and (ii) purchases of long-term inventory. We also exclude the impact of corresponding inventory valuation adjustments, as applicable.

(4) We carry crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We exclude the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and write-downs of such inventory that result from price declines from Segment Adjusted EBITDA.

(5) We, and certain of our equity method investees, have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Substantially all of such agreements were entered into with counterparties to economically support the return on capital expenditure necessary to construct the related asset. Some of these agreements include make-up rights if the minimum volume is not met. We record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty's make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty's ability to utilize the make-up right is remote. We include the impact of amounts billed to counterparties for their deficiency obligation, net of applicable amounts subsequently recognized into revenue or equity earnings, as a selected item impacting comparability. Our CODM views the inclusion of the contractually committed revenues associated with that period as meaningful to Segment Adjusted EBITDA as the related asset has been constructed, is standing ready to provide the committed service and the fixed operating costs are included in the current period results.

(6) Our total equity-indexed compensation expense includes expense associated with awards that will be settled in units and awards that will be settled in cash. The awards that will be settled in units are included in our diluted net income per unit calculation when the applicable performance criteria have been met. We exclude compensation expense associated with these awards in determining Segment Adjusted EBITDA as the dilutive impact of the outstanding awards is included in our diluted net income per unit calculation, as applicable. The portion of compensation expense associated with awards that will be settled in cash is not excluded in determining Segment Adjusted EBITDA. See Note 17 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for a discussion regarding our equity-indexed compensation plans.

(7) During the periods presented, there were fluctuations in the value of CAD to USD, resulting in the realization of foreign exchange gains and losses on the settlement of foreign currency transactions as well as the revaluation of monetary assets and liabilities denominated in a foreign currency. These gains and losses are not integral to our core operating performance and were therefore excluded in determining Segment Adjusted EBITDA.

(8) Reflects amounts attributable to noncontrolling interests in the Permian JV, Cactus II and Red River.

Item 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical Consolidated Financial Statements and accompanying notes and Management’s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2023 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the Condensed Consolidated Financial Statements and related notes that are contained in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Our discussion and analysis includes the following:

- Executive Summary
- Results of Operations
- Liquidity and Capital Resources
- Recent Accounting Pronouncements
- Forward-Looking Statements

Executive Summary

Company Overview

Our business model integrates large-scale supply aggregation capabilities with the ownership and operation of critical midstream infrastructure systems that connect major producing regions to key demand centers and export terminals. As one of the largest midstream service providers in North America, we own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins (including the Permian Basin) and transportation corridors and at major market hubs in the United States and Canada. Our assets and the services we provide are primarily focused on crude oil and NGL.

Overview of Operating Results

During the first three months of 2024, we recognized net income attributable to PAA of $266 million compared to $422 million during the first three months of 2023. Net income for the 2023 period includes favorable impacts from gains on asset sales and the mark-to-market adjustment of the Preferred Distribution Rate Reset Option, contributing to the relative decrease in net income in 2024. For the first quarter of 2024 compared to 2023, more favorable results from our Crude Oil segment were substantially offset by less favorable results from our NGL segment.

See the “Results of Operations” section below for further discussion.

Results of Operations

Consolidated Results

The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP (in millions, except per unit data):

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Variance $	Variance %
Product sales revenues	$ 11,546	$ 11,943	$ (397)	(3)%
Services revenues	449	398	51	13 %
Purchases and related costs	(10,917)	(11,323)	406	4 %
Field operating costs	(358)	(357)	(1)	— %
General and administrative expenses	(96)	(86)	(10)	(12)%
Depreciation and amortization	(254)	(256)	2	1 %
Gains/(losses) on asset sales, net	—	154	(154)	(100)%
Equity earnings in unconsolidated entities	95	89	6	7 %
Interest expense, net	(95)	(98)	3	3 %
Other income/(expense), net	(5)	64	(69)	(108)%
Income tax expense	(14)	(53)	39	74 %
Net income	351	475	(124)	(26)%
Net income attributable to noncontrolling interests	(85)	(53)	(32)	(60)%
Net income attributable to PAA	$ 266	$ 422	$ (156)	(37)%
Basic and diluted net income per common unit	$ 0.29	$ 0.52	$ (0.23)	**
Basic and diluted weighted average common units outstanding	701	698	3	**

** Indicates that variance as a percentage is not meaningful.

Revenues and Purchases

Fluctuations in our consolidated revenues and purchases and related costs are primarily associated with our merchant activities and generally explained in large part by changes in commodity prices. Our crude oil and NGL merchant activities are not directly affected by the absolute level of prices because the commodities that we buy and sell are generally indexed to the same pricing indices. Both product sales revenues and purchases and related costs will fluctuate with market prices; however, the absolute margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. Additionally, product sales revenues include the impact of gains and losses related to derivative instruments used to manage our exposure to commodity price risk associated with such sales and purchases.

A majority of our sales and purchases are indexed to the prompt month price of the NYMEX Light, Sweet crude oil futures contract ("NYMEX Price"). The following table presents the range of the NYMEX Price over the last two years (in dollars per barrel):

	NYMEX Price Low	NYMEX Price High	NYMEX Price Average
Three Months Ended March 31, 2024	$ 70	$ 83	$ 77
Three Months Ended March 31, 2023	$ 67	$ 82	$ 76

Product sales revenues and purchases for the three months ended March 31, 2024 were relatively in line with product sales revenues and purchases for the three months ended March 31, 2023.

Revenues from services increased for the three months ended March 31, 2024 compared to the same period in 2023 primarily due to higher pipeline volumes and tariff escalations, as well as the impact of acquisitions.

See further discussion of our net revenues (revenues less purchases and related costs) in the "—Analysis of Operating Segments" section below.

Field Operating Costs

See discussion of field operating costs in the "—Analysis of Operating Segments" section below.

General and Administrative Expenses

The increase in general and administrative expenses for the three months ended March 31, 2024 compared to the same period in 2023 was primarily due to (i) higher information systems costs due to ongoing systems integration work and (ii) higher employee-related costs, including an increase in equity-indexed compensation expense (a portion of which is excluded in the calculation of Adjusted EBITDA and Segment Adjusted EBITDA).

Gains/(Losses) on Asset Sales, Net

The net gain on asset sales for the three months ended March 31, 2023 was primarily comprised of a gain of approximately $140 million related to the sale of our Keyera Fort Saskatchewan facility in the first quarter of 2023. See Note 7 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for additional information.

Other Income/(Expense), Net

The following table summarizes the components impacting Other income/(expense), net (in millions):

	Three Months Ended March 31,	
	2024	**2023**
Net loss on foreign currency revaluation (1)	$ (12)	$ —
Gain on mark-to-market adjustment of Preferred Distribution Rate Reset Option embedded derivative (2)	—	58
Other	7	6
	$ (5)	$ 64

(1) The activity during the periods presented was primarily related to the impact from the change in the USD to CAD exchange rate on the portion of our intercompany net investment that is not long-term in nature.

(2) See Note 7 to our Condensed Consolidated Financial Statements for additional information.

Income Tax (Expense)/Benefit

The net favorable income tax variance for the three months ended March 31, 2024 compared to the same period in 2023 was primarily due to the tax impact of the Keyera Fort Saskatchewan divestiture in the first quarter of 2023 and lower year-over-year income within our Canadian operations.

Noncontrolling Interests

The increase in amounts attributable to noncontrolling interests for the three months ended March 31, 2024 compared to the same period in 2023 was primarily due to higher income recognized by the Permian JV resulting from higher volumes and contributions from acquisitions.

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future and to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases and other general partnership purposes. The primary additional measures used by management are Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied distributable cash flow (“DCF”), Adjusted Free Cash Flow and Adjusted Free Cash Flow after Distributions.

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA, Adjusted EBITDA attributable to PAA and Implied DCF are reconciled to Net Income, and Adjusted Free Cash Flow and Adjusted Free Cash Flow after Distributions are reconciled to Net Cash Provided by Operating Activities, the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Condensed Consolidated Financial Statements and accompanying notes. See “—Liquidity and Capital Resources—Non-GAAP Financial Liquidity Measures” for additional information regarding Adjusted Free Cash Flow and Adjusted Free Cash Flow after Distributions.

Non-GAAP Financial Performance Measures

Adjusted EBITDA is defined as earnings before interest expense, income taxes, depreciation and amortization (including our proportionate share of depreciation and amortization, including write-downs related to cancelled projects and impairments, of unconsolidated entities), gains and losses on asset sales and gains or losses on investments in unconsolidated entities, adjusted for certain selected items impacting comparability. Adjusted EBITDA attributable to PAA excludes the portion of Adjusted EBITDA that is attributable to noncontrolling interests.

Management believes that the presentation of Adjusted EBITDA, Adjusted EBITDA attributable to PAA and Implied DCF provides useful information to investors regarding our performance and results of operations because these measures, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance and ability to fund distributions to our unitholders through cash generated by our operations, (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions and (iii) present measures that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These non-GAAP financial performance measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) gains and losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are either related to investing activities (such as the purchase of linefill) or purchases of long-term inventory, and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and/or (v) other items that we believe should be excluded in understanding our core operating performance. These measures may further be adjusted to include amounts related to deficiencies associated with minimum volume commitments whereby we have billed the counterparties for their deficiency obligation and such amounts are recognized as deferred revenue in “Other current liabilities” in our Condensed Consolidated Financial Statements. We also adjust for amounts billed by our equity method investees related to deficiencies under minimum volume commitments. Such amounts are presented net of applicable amounts subsequently recognized into revenue. We have defined all such items as “selected items impacting comparability.” We do not necessarily consider all of our selected items impacting comparability to be non-recurring, infrequent or unusual, but we believe that an understanding of these selected items impacting comparability is material to the evaluation of our operating results and prospects.

Although we present selected items impacting comparability that management considers in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions, divestitures, investment capital projects and numerous other factors as discussed, as applicable, in “—Analysis of Operating Segments.”

The following tables set forth the reconciliation of the non-GAAP financial performance measures Adjusted EBITDA, Adjusted EBITDA attributable to PAA and Implied DCF to Net Income (in millions):

	Three Months Ended March 31,		Variance	
	2024	2023	$	%
Net income	$ 351	$ 475	$ (124)	(26)%
Interest expense, net	95	98	(3)	(3)%
Income tax expense	14	53	(39)	(74)%
Depreciation and amortization	254	256	(2)	(1)%
(Gains)/losses on asset sales, net	—	(154)	154	100 %
Depreciation and amortization of unconsolidated entities [1]	19	22	(3)	(14)%
Selected Items Impacting Comparability:				
Derivative activities and inventory valuation adjustments	159	92	67	**
Long-term inventory costing adjustments	(33)	29	(62)	**
Deficiencies under minimum volume commitments, net	(12)	(7)	(5)	**
Equity-indexed compensation expense	9	10	(1)	**
Foreign currency revaluation	(21)	(3)	(18)	**
Selected Items Impacting Comparability - Segment Adjusted EBITDA [2]	102	121	(19)	**
Mark-to-market adjustment of Preferred Distribution Rate Reset Option embedded derivative [3]	—	(58)	58	**
Foreign currency revaluation [4]	12	—	12	**
Selected Items Impacting Comparability - Adjusted EBITDA [5]	114	63	51	**
Adjusted EBITDA [5]	$ 847	$ 813	$ 34	4 %
Adjusted EBITDA attributable to noncontrolling interests [6]	(129)	(98)	(31)	(32)%
Adjusted EBITDA attributable to PAA	$ 718	$ 715	$ 3	— %
Adjusted EBITDA [5] [7]	$ 847	$ 813	$ 34	4 %
Interest expense, net of certain non-cash items [8]	(90)	(93)	3	3 %
Maintenance capital [9]	(57)	(48)	(9)	(19)%
Investment capital of noncontrolling interests [10]	(25)	(23)	(2)	(9)%
Current income tax expense	(53)	(61)	8	13 %
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings [11]	12	(12)	24	**
Distributions to noncontrolling interests [12]	(100)	(78)	(22)	(28)%
Implied DCF	$ 534	$ 498	$ 36	7 %
Preferred unit distributions [12]	(64)	(55)	(9)	(16)%
Implied DCF Available to Common Unitholders	$ 470	$ 443	$ 27	6 %
Common unit cash distributions [12]	(223)	(187)		
Implied DCF Excess [13]	$ 247	$ 256		

** Indicates that variance as a percentage is not meaningful.

(1) We exclude our proportionate share of the depreciation and amortization expense (including write-downs related to cancelled projects and impairments) of unconsolidated entities when reviewing Adjusted EBITDA, similar to our consolidated assets.

(2) For a more detailed discussion of these selected items impacting comparability, see the footnotes to the Segment Adjusted EBITDA Reconciliation table in Note 10 to our Condensed Consolidated Financial Statements.

(3) The Preferred Distribution Rate Reset Option of our Series A preferred units was accounted for as an embedded derivative and recorded at fair value in our Condensed Consolidated Financial Statements. The associated gains and losses are not integral to our results and were thus classified as a selected item impacting comparability. See Note 7 to our Condensed Consolidated Financial Statements for additional information regarding the Preferred Distribution Rate Reset Option.

(4) During the periods presented, there were fluctuations in the value of CAD to USD, resulting in the realization of foreign exchange gains and losses on the settlement of foreign currency transactions as well as the revaluation of monetary assets and liabilities denominated in a foreign currency. The associated gains and losses are not integral to our results and were thus classified as a selected item impacting comparability.

(5) Other income/(expense), net on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability ("Adjusted other income/(expense), net") is included in Adjusted EBITDA and excluded from Segment Adjusted EBITDA.

(6) Reflects amounts attributable to noncontrolling interests in the Permian JV, Cactus II and Red River.

(7) See the table above for a reconciliation from Net Income to Adjusted EBITDA.

(8) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

(9) Maintenance capital expenditures are defined as capital expenditures for the replacement and/or refurbishment of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets.

(10) Investment capital expenditures attributable to noncontrolling interests that reduce Implied DCF available to PAA common unitholders.

(11) Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, and selected items impacting comparability of unconsolidated entities).

(12) Cash distributions paid during the period presented.

(13) Excess DCF is retained to establish reserves for debt repayment, future distributions, common equity repurchases, capital expenditures and other partnership purposes.

Analysis of Operating Segments

We manage our operations through two operating segments: Crude Oil and NGL. Our CODM (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Adjusted EBITDA, segment volumes and maintenance capital investment. See Note 10 to our Condensed Consolidated Financial Statements for our definition of Segment Adjusted EBITDA and a reconciliation of Segment Adjusted EBITDA to Net income attributable to PAA. See Note 19 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for our definition of maintenance capital.

Crude Oil Segment

Our Crude Oil segment operations generally consist of gathering and transporting crude oil using pipelines, gathering systems, trucks and, at times, on barges or railcars, in addition to providing terminalling, storage and other related services utilizing our integrated assets across the United States and Canada. Our assets serve third parties and are also supported by our merchant activities. Our merchant activities include the purchase of crude oil supply and the movement of this supply on our assets or third-party assets to sales locations, including our terminals, third-party connecting carriers, regional hubs or to refineries. Our merchant activities are subject to our risk management policies and may include the use of derivative instruments to manage exposure to commodity price risk and, at times, to provide upside opportunities.

Our Crude Oil segment generates revenue through a combination of tariffs, pipeline capacity agreements and other transportation fees, month-to-month and multi-year storage and terminalling agreements and the sale of gathered and bulk-purchased crude oil. Tariffs and other fees on our pipeline systems are typically based on volumes transported and vary by receipt point and delivery point. Fees for our terminalling and storage services are based on capacity leases and throughput volumes. Generally, results from our merchant activities are impacted by (i) increases or decreases in our lease gathering crude oil purchases volumes and (ii) volatility in commodity price differentials, particularly grade and location differentials, as well as time spreads. The segment results also include the direct fixed and variable field costs of operating the crude oil assets, as well as an allocation of indirect operating costs.

The following tables set forth our operating results from our Crude Oil segment:

Operating Results [1]	**Three Months Ended March 31,**		**Variance**	
(in millions)	**2024**	**2023**	**$**	**%**
Revenues	$ 11,582	$ 11,758	$ (176)	(1)%
Purchases and related costs	(10,665)	(10,940)	275	3 %
Field operating costs	(266)	(257)	(9)	(4)%
Segment general and administrative expenses [2]	(73)	(67)	(6)	(9)%
Equity earnings in unconsolidated entities	95	89	6	7 %
Adjustments [3]:				
Depreciation and amortization of unconsolidated entities	19	22	(3)	**
Derivative activities and inventory valuation adjustments	37	(12)	49	**
Long-term inventory costing adjustments	(28)	21	(49)	**
Deficiencies under minimum volume commitments, net	(12)	(7)	(5)	**
Equity-indexed compensation expense	9	10	(1)	**
Foreign currency revaluation	(17)	(2)	(15)	**
Segment amounts attributable to noncontrolling interests	(128)	(98)	(30)	**
Segment Adjusted EBITDA	$ 553	$ 517	$ 36	7 %
Maintenance capital expenditures	$ 46	$ 32	$ 14	44 %

	Three Months Ended March 31,		**Variance**	
Average Volumes	**2024**	**2023**	**Volumes**	**%**
Crude oil pipeline tariff (by region) [4]				
Permian Basin [5]	6,428	6,295	133	2 %
Other [5]	2,172	1,985	187	9 %
Total crude oil pipeline tariff	8,600	8,280	320	4 %
Commercial crude oil storage capacity [5][6]	72	72	—	— %
Crude oil lease gathering purchases [4]	1,508	1,428	80	6 %

** Indicates that variance as a percentage is not meaningful.

(1) Revenues and costs and expenses include intersegment amounts.

(2) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 10 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

(4) Average daily volumes in thousands of barrels per day calculated as the total volumes (attributable to our interest for assets owned by unconsolidated entities or through undivided joint interests) for the period divided by the number of days in the period. Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

(5) Includes volumes (attributable to our interest) from assets owned by unconsolidated entities.

(6) Average monthly capacity in millions of barrels per day calculated as total volumes for the period divided by the number of months in the period.

Segment Adjusted EBITDA

Crude Oil Segment Adjusted EBITDA increased for the three months ended March 31, 2024 compared to the same period in 2023 primarily due to higher tariff volumes on our pipelines, tariff escalations and contributions from acquisitions, partially offset by fewer market-based opportunities.

The following is a more detailed discussion of the significant factors impacting Segment Adjusted EBITDA for the three months ended March 31, 2024 compared to the same period in 2023.

Net Revenues and Equity Earnings. Our results were favorably impacted by (i) higher volumes across our pipeline systems driven by increased production as well as increased movements from the Rocky Mountain region to Cushing, Oklahoma, (ii) tariff escalations and (iii) contributions from acquisitions.

Additionally, our results for the three months ended March 31, 2024 compared to 2023 reflect fewer crude oil market-based opportunities.

Field Operating Costs. For the three months ended March 31, 2024 compared to the same period in 2023, we recognized higher expenses associated with (i) employee-related costs primarily resulting from higher average headcount and salaries, (ii) property taxes due to the impact of adjustments received in 2023 and (iii) incremental consolidated operating costs in connection with acquisitions. The unfavorable variance for the three months ended March 31, 2024 compared to 2023 was partially offset by (iv) lower utilities-related costs as a result of lower prices, (v) a decrease in the amount of drag reducing agents used and (vi) decreased costs resulting from lower third-party trucked volumes.

Maintenance Capital

The increase in maintenance capital spending for the three months ended March 31, 2024 compared to the same period in 2023 was primarily due to timing of routine integrity maintenance.

NGL Segment

Our NGL segment operations involve natural gas processing and NGL fractionation, storage, transportation and terminalling. Our NGL revenues are primarily derived from a combination of (i) providing gathering, fractionation, storage, and/or terminalling services to third-party customers for a fee, and (ii) extracting NGL mix from the gas stream processed at our Empress straddle plant facility as well as acquiring NGL mix, which is then transported, stored and fractionated into finished products and sold to customers. Our management of our commodity exposure is subject to our risk management policies and may include the use of derivative instruments to mitigate the risk of such exposure and, at times, to provide upside opportunities.

Generally, our segment results are impacted by (i) increases or decreases in our NGL sales volumes, (ii) volatility in commodity price differentials, primarily the differential between the price of natural gas and the extracted NGL ("frac spread"), as well as location differentials and time spreads, (iii) the volume of natural gas transported on third-party assets through our Empress straddle plant and (iv) our share of the NGL's received from a third party straddle plant.

Our NGL operations are sensitive to weather-related demand, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on NGL demand and thus our financial performance as well as the impact of comparative performance between financial reporting periods that bisect the five-month peak heating season.

The following tables set forth our operating results from our NGL segment:

Operating Results [1] (in millions)	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Variance $	Variance %
Revenues	$ 507	$ 690	$ (183)	(27)%
Purchases and related costs	(346)	(490)	144	29 %
Field operating costs	(92)	(100)	8	8 %
Segment general and administrative expenses [2]	(23)	(19)	(4)	(21)%
Adjustments [3]:				
Derivative activities	122	104	18	**
Long-term inventory costing adjustments	(5)	8	(13)	**
Foreign currency revaluation	(4)	(1)	(3)	**
Segment Adjusted EBITDA	$ 159	$ 192	$ (33)	(17)%
Maintenance capital expenditures	$ 11	$ 16	$ (5)	(31)%

Average Volumes (in thousands of barrels per day) [4]	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Variance Volumes	Variance %
NGL fractionation	128	144	(16)	(11)%
NGL pipeline tariff	214	194	20	10 %
Propane and butane sales	128	138	(10)	(7)%

** Indicates that variance as a percentage is not meaningful.

(1) Revenues and costs and expenses include intersegment amounts.

(2) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 10 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

(4) Average daily volumes are calculated as total volumes (attributable to our interest for assets owned through undivided joint interests) for the period divided by the number of days in the period.

Segment Adjusted EBITDA

NGL Segment Adjusted EBITDA decreased for the three months ended March 31, 2024 compared to the same period in 2023 primarily due to lower realized frac spreads.

Significant variances in the components of Segment Adjusted EBITDA are discussed in more detail below.

Net Revenues. Net revenues include the impact of derivative activities and long-term inventory costing adjustments, which are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above. Excluding such impacts, net revenues decreased for the three months ended March 31, 2024 compared to the same period in 2023 primarily due to (i) lower realized frac spreads, (ii) lower propane and butane sales volumes, and (iii) lower field operating costs recoveries at our Empress straddle plants realized through our commercial agreements.

Field Operating Costs. The decrease in field operating costs for the three months ended March 31, 2024 compared to the same period in 2023 was primarily due to decreased utilities-related costs, largely as a result of lower prices. This decrease was partially offset by the lower benefit to net revenues of operating cost recoveries realized through commercial agreements.

Maintenance Capital

The decrease in maintenance capital spending for the three months ended March 31, 2024 compared to the same period in 2023 was primarily due to timing of equipment repairs and replacement projects for certain of our pipeline systems and fractionation facilities.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities and (ii) borrowings under our credit facilities or commercial paper program. In addition, we may supplement these primary sources of liquidity with proceeds from asset sales, and in the past have utilized funds received from sales of equity and debt securities. Our primary cash requirements include, but are not limited to, (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products, payment of other expenses and interest payments on outstanding debt, (ii) investment and maintenance capital activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and noncontrolling interests. In addition, we may use cash for repurchases of common equity. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under our credit facilities or commercial paper program. In addition, we generally expect to fund our long-term needs, such as those resulting from investment capital activities, acquisitions or refinancing our long-term debt, through a variety of sources, which may include any or a combination of the sources listed above.

As of March 31, 2024, although we had a working capital deficit of $143 million, we had approximately $2.4 billion of liquidity available to meet our ongoing operating, investing and financing needs, subject to continued covenant compliance, as noted below (in millions):

	As of March 31, 2024
Availability under senior unsecured revolving credit facility [1] [2]	$ 1,350
Availability under senior secured hedged inventory facility [1] [2]	1,323
Amounts outstanding under commercial paper program	(540)
Subtotal	2,133
Cash and cash equivalents [3]	316
Total	$ 2,449

(1) Represents availability prior to giving effect to borrowings outstanding under our commercial paper program, which reduce available capacity under our credit facilities.

(2) Available capacity under our senior unsecured revolving credit facility and senior secured hedged inventory facility was reduced by outstanding letters of credit issued under these facilities of less than $1 million and $27 million, respectively.

(3) Excludes restricted cash of $15 million.

Usage of our credit facilities, and, in turn, our commercial paper program, is subject to ongoing compliance with covenants. The credit agreements for our revolving credit facilities (which impact our ability to access our commercial paper program because they provide the financial backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements or indentures would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. We were in compliance with the covenants contained in our credit agreements and indentures as of March 31, 2024.

We believe that we have, and will continue to have, the ability to access our commercial paper program and credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquid assets, cash flow from operating activities and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, subject to business and operational risks that could adversely affect our cash flow, including extended disruptions in the financial markets and/or energy price volatility resulting from current macroeconomic and geopolitical conditions, including actions by the Organization of Petroleum Exporting Countries (OPEC). A prolonged material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity and cost of borrowing. Our borrowing capacity and borrowing costs are also impacted by our credit rating. See Item 1A. “Risk Factors” included in our 2023 Annual Report on Form 10-K for further discussion regarding risks that may impact our liquidity and capital resources.

Non-GAAP Financial Liquidity Measures

Management uses the non-GAAP financial liquidity measures Adjusted Free Cash Flow and Adjusted Free Cash Flow after Distributions to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases and other general partnership purposes. Adjusted Free Cash Flow is defined as Net cash provided by operating activities, less Net cash provided by/(used in) investing activities, which primarily includes acquisition, investment and maintenance capital expenditures, investments in unconsolidated entities and the impact from the purchase and sale of linefill, net of proceeds from the sales of assets and further impacted by distributions to and contributions from noncontrolling interests. Adjusted Free Cash Flow is further reduced by cash distributions paid to our preferred and common unitholders to arrive at Adjusted Free Cash Flow after Distributions. Also see “Results of Operations–Non-GAAP Financial Measures” above for more information about our non-GAAP measures.

The following table sets forth the reconciliation of the non-GAAP financial liquidity measures Adjusted Free Cash Flow and Adjusted Free Cash Flow after Distributions from Net Cash Provided by Operating Activities (in millions):

	Three Months Ended March 31,	
	2024	2023
Net cash provided by operating activities	$ 419	$ 743
Adjustments to reconcile net cash provided by operating activities to adjusted free cash flow:		
Net cash provided by/(used in) investing activities	(261)	158
Cash contributions from noncontrolling interests	12	—
Cash distributions paid to noncontrolling interests [1]	(100)	(78)
Adjusted Free Cash Flow	$ 70	$ 823
Cash distributions [2]	(287)	(242)
Adjusted Free Cash Flow after Distributions	$ (217)	$ 581

(1) Cash distributions paid during the period presented.

(2) Cash distributions paid to our preferred and common unitholders during the period presented.

Cash Flow from Operating Activities

For a comprehensive discussion of the primary drivers of cash flow from operating activities, including the impact of varying market conditions and the timing of settlement of our derivatives, see Item 7. "Liquidity and Capital Resources—Cash Flow from Operating Activities" included in our 2023 Annual Report on Form 10-K.

Net cash provided by operating activities for the first three months of 2024 and 2023 was $419 million and $743 million, respectively, and primarily resulted from earnings from our operations. Both periods were also impacted by changes in working capital items. The 2024 period was impacted unfavorably, primarily by margin requirements related to our hedging activities. The 2023 period was impacted favorably, largely associated with reducing inventory levels during the period.

Investing Activities

Capital Expenditures

In addition to our operating needs, we also use cash for our investment capital projects, maintenance capital activities and acquisition activities. We fund these expenditures with cash generated by operating activities, financing activities and/or proceeds from asset sales. The following table summarizes our investment, maintenance and acquisition capital expenditures (in millions):

	Three Months Ended March 31,	
	2024	2023
Investment capital [1] [2] [3]	$ 104	$ 80
Maintenance capital [1] [3]	57	48
Acquisition capital [2] [4]	93	—
	$ 254	$ 128

(1) Capital expenditures made to expand the existing operating and/or earnings capacity of our assets are classified as "Investment capital". Capital expenditures made to replace and/or refurbish partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets are classified as "Maintenance capital".

(2) Contributions to unconsolidated entities, accounted for under the equity method of accounting, that are related to investment capital projects by such entities are recognized in "Investment capital". Acquisitions of initial investments or additional interests in unconsolidated entities are included in "Acquisition capital".

(3) Investment capital and maintenance capital, net to our 65% interest in the Permian JV, was approximately $79 million and $53 million, respectively, for the three months ended March 31, 2024, and approximately $58 million and $45 million, respectively, for the three months ended March 31, 2023.

(4) Acquisition capital for the 2024 period primarily includes the acquisition of an additional ownership interest in an equity method investee.

2024 Investment and Maintenance Capital. Total investment capital for the year ending December 31, 2024 is projected to be approximately $465 million ($375 million net to our interest). Approximately half of our projected investment capital expenditures are expected to be invested in the Permian JV assets. Additionally, maintenance capital for 2024 is projected to be approximately $250 million ($230 million net to our interest). We expect to fund our 2024 investment and maintenance capital expenditures primarily with retained cash flow.

Divestitures

Proceeds from the sale of assets have generally been used to fund our investment capital projects and reduce debt levels. The following table summarizes the proceeds received during the first three months of 2024 and 2023 from sales of assets (in millions):

	Three Months Ended March 31,	
	2024	2023
Proceeds from divestitures [1]	$ 3	$ 284

(1) Represents proceeds, including working capital adjustments, net of transaction costs. The proceeds from divestitures for the three months ended March 31, 2023 were primarily from the sale of our 21% non-operated/undivided joint interest in the Keyera Fort Saskatchewan facility in February 2023. See Note 7 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for additional discussion of this transaction.

Ongoing Activities Related to Strategic Transactions

We are continuously engaged in the evaluation of potential transactions that support our current business strategy. In the past, such transactions have included the acquisition of assets that complement our existing footprint, the sale of non-core assets, the sale of partial interests in assets to strategic joint venture partners, and large investment capital projects. With respect to a potential acquisition or divestiture, we may conduct an auction process or participate in an auction process conducted by a third party or we may negotiate a transaction with one or a limited number of potential sellers (in the case of an acquisition) or buyers (in the case of a divestiture). Such transactions could have a material effect on our financial condition and results of operations.

We typically do not announce a transaction until after we have executed a definitive agreement. In certain cases, in order to protect our business interests or for other reasons, we may defer public announcement of a transaction until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential transaction can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive agreement may be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future efforts with respect to any such transactions will be successful, and we can provide no assurance that our financial expectations with respect to such transactions will ultimately be realized. See Item 1A. "Risk Factors—Risks Related to Our Business—Acquisitions and divestitures involve risks that may adversely affect our business" included in our 2023 Annual Report on Form 10-K.

Financing Activities

Our financing activities primarily relate to funding investment capital projects, acquisitions and refinancing of our debt maturities, as well as short-term working capital (including borrowings for NYMEX and ICE margin deposits) and hedged inventory borrowings related to our NGL business and contango market activities.

Borrowings and Repayments Under Credit Agreements

During the three months ended March 31, 2024, we had net borrowings under our commercial paper program of $107 million. The net borrowings resulted primarily from borrowings during the period related to funding needs for capital investments, inventory purchases and other general partnership purposes.

We had no net borrowings or repayments under our credit facilities or commercial paper program during the three months ended March 31, 2023.

Common Equity Repurchase Program

There were no repurchases under the Common Equity Repurchase Program (the "Program") during the three months ended March 31, 2024 or 2023. The remaining available capacity under the Program as of March 31, 2024 was $198 million.

Registration Statements

We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to a specified amount of debt or equity securities ("Traditional Shelf"), under which we had approximately $1.1 billion of unsold securities available at March 31, 2024. We also have access to a universal shelf registration statement ("WKSI Shelf"), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. We did not conduct any offerings under our Traditional Shelf or WKSI Shelf during the three months ended March 31, 2024.

Distributions to Our Unitholders

Series A preferred unitholders. On May 15, 2024, we will pay a quarterly cash distribution of approximately $0.615 per unit to Series A preferred unitholders of record at the close of business on May 1, 2024 for the period from January 1, 2024 through March 31, 2024.

Series B preferred unitholders. On May 15, 2024, we will pay a quarterly cash distribution of approximately $24.20 per unit to Series B preferred unitholders of record at the close of business on May 1, 2024 for the period from February 15, 2024 through May 14, 2024.

Common Unitholders. On May 15, 2024, we will pay a quarterly cash distribution of $0.3175 per common unit ($1.27 per unit on an annualized basis) to common unitholders of record at the close of business on May 1, 2024 for the period from January 1, 2024 through March 31, 2024, which is unchanged from the distribution per unit paid in February of 2024.

See Note 6 to our Condensed Consolidated Financial Statements for details of distributions paid during or pertaining to the first three months of 2024, including distributions to our preferred unitholders.

Distributions to Noncontrolling Interests

Distributions to noncontrolling interests represent amounts paid on interests in consolidated entities that are not owned by us. As of March 31, 2024, noncontrolling interests in our subsidiaries consisted of (i) a 35% interest in the Permian JV, (ii) a 30% interest in Cactus II and (iii) a 33% interest in Red River. See Note 6 to our Condensed Consolidated Financial Statements for details of distributions paid to noncontrolling interests during the three months ended March 31, 2024.

Contingencies

For a discussion of contingencies that may impact us, see Note 9 to our Condensed Consolidated Financial Statements.

Commitments

Purchase Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years, with a limited number of contracts with remaining terms extending up to 11 years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

The following table includes our best estimate of the amount and timing of these payments as of March 31, 2024 (in millions):

	Remainder of 2024	2025	2026	2027	2028	2029 and Thereafter	Total
Crude oil, NGL and other purchases (1)	$ 20,135	$ 21,649	$ 19,624	$ 17,031	$ 13,914	$ 34,178	$ 126,531

(1) Amounts are primarily based on estimated volumes and market prices based on average activity during March 2024. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our merchant activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase and transportation of crude oil, NGL and natural gas. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the product is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At March 31, 2024 and December 31, 2023, we had outstanding letters of credit of approximately $161 million and $205 million, respectively.

Recent Accounting Pronouncements

See Note 1 to our Condensed Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words “anticipate,” “believe,” “estimate,” “expect,” “plan,” “intend” and “forecast,” as well as similar expressions and statements regarding our business strategy, plans and objectives for future operations. The absence of such words, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- general economic, market or business conditions in the United States and elsewhere (including the potential for a recession or significant slowdown in economic activity levels, the risk of persistently high inflation and continued supply chain issues, the impact of global public health events, such as pandemics, on demand and growth, and the timing, pace and extent of economic recovery) that impact (i) demand for crude oil, drilling and production activities and therefore the demand for the midstream services we provide and (ii) commercial opportunities available to us;

- declines in global crude oil demand and/or crude oil prices or other factors that correspondingly lead to a significant reduction of North American crude oil and natural gas liquids ("NGL") production (whether due to reduced producer cash flow to fund drilling activities or the inability of producers to access capital, or both, the unavailability of pipeline and/or storage capacity, the shutting-in of production by producers, government-mandated pro-ration orders, or other factors), which in turn could result in significant declines in the actual or expected volume of crude oil and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our assets and/or the reduction of the margins we can earn or the commercial opportunities that might otherwise be available to us;
- fluctuations in refinery capacity and other factors affecting demand for various grades of crude oil and NGL and resulting changes in pricing conditions or transportation throughput requirements;
- unanticipated changes in crude oil and NGL market structure, grade differentials and volatility (or lack thereof);
- the effects of competition and capacity overbuild in areas where we operate, including downward pressure on rates, volumes and margins, contract renewal risk and the risk of loss of business to other midstream operators who are willing or under pressure to aggressively reduce transportation rates in order to capture or preserve customers;
- negative societal sentiment regarding the hydrocarbon energy industry and the continued development and consumption of hydrocarbons, which could influence consumer preferences and governmental or regulatory actions that adversely impact our business;
- environmental liabilities, litigation or other events that are not covered by an indemnity, insurance or existing reserves;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event that materially impacts our operations, including cyber or other attacks on our electronic and computer systems;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the impact of current and future laws, rulings, legislation, governmental regulations, executive orders, trade policies, accounting standards and statements, and related interpretations that (i) prohibit, restrict or regulate the development of oil and gas resources and the related infrastructure on lands dedicated to or served by our pipelines or (ii) negatively impact our ability to develop, operate or repair midstream assets;
- negative impacts on production levels in the Permian Basin or elsewhere due to issues associated with (or laws, rules or regulations relating to) hydraulic fracturing and related activities (including wastewater injection or disposal), including earthquakes, subsidence, expansion or other issues;
- loss of key personnel and inability to attract and retain new talent;
- disruptions to futures markets for crude oil, NGL and other petroleum products, which may impair our ability to execute our commercial or hedging strategies;
- the effectiveness of our risk management activities;
- shortages or cost increases of supplies, materials or labor;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- the successful operation of joint ventures and joint operating arrangements we enter into from time to time, whether relating to assets operated by us or by third parties, and the successful integration and future performance of acquired assets or businesses;
- the availability of, and our ability to consummate, acquisitions, divestitures, joint ventures or other strategic opportunities;
- the refusal or inability of our customers or counterparties to perform their obligations under their contracts with us (including commercial contracts, asset sale agreements and other agreements), whether justified or not and whether due to financial constraints (such as reduced creditworthiness, liquidity issues or insolvency), market constraints, legal constraints (including governmental orders or guidance), the exercise of contractual or common law rights that allegedly excuse their performance (such as force majeure or similar claims) or other factors;

- our inability to perform our obligations under our contracts, whether due to non-performance by third parties, including our customers or counterparties, market constraints, third-party constraints, supply chain issues, legal constraints (including governmental orders or guidance), or other factors or events;
- the incurrence of costs and expenses related to unexpected or unplanned capital expenditures, third-party claims or other factors;
- failure to implement or capitalize, or delays in implementing or capitalizing, on investment capital projects, whether due to permitting delays, permitting withdrawals or other factors;
- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, investment capital projects, working capital requirements and the repayment or refinancing of indebtedness;
- the amplification of other risks caused by volatile financial markets, capital constraints, liquidity concerns and inflation;
- the use or availability of third-party assets upon which our operations depend and over which we have little or no control;
- the currency exchange rate of the Canadian dollar to the United States dollar;
- inability to recognize current revenue attributable to deficiency payments received from customers who fail to ship or move more than minimum contracted volumes until the related credits expire or are used;
- significant under-utilization of our assets and facilities;
- increased costs, or lack of availability, of insurance;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;
- risks related to the development and operation of our assets;
- the pace of development of natural gas infrastructure and its impact on expected crude oil production growth in the Permian Basin; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, as well as in the processing, transportation, fractionation, storage and marketing of NGL.

Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read “Risk Factors” discussed in Item 1A of our 2023 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various market risks, including commodity price risk and interest rate risk. We use various derivative instruments to manage such risks and, in certain circumstances, to realize incremental margin during volatile market conditions. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our exchange-cleared and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

We use derivative instruments to hedge price risk associated with the following commodities:

- *Crude oil*

  We utilize crude oil derivatives to hedge commodity price risk inherent in our pipeline, terminalling and merchant activities. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory and basis differentials. We manage these exposures with various instruments including futures, forwards, swaps and options.

- *Natural gas*

  We utilize natural gas derivatives to hedge commodity price risk inherent in our natural gas processing assets (natural gas purchase component of the frac spread). Additionally, we utilize natural gas derivatives to hedge anticipated operational fuel gas requirements related to our natural gas processing and NGL fractionation plants. We manage these exposures with various instruments including futures, swaps and options.

- *NGL and other*

  We utilize NGL derivatives, primarily propane and butane derivatives, to hedge commodity price risk inherent in our commercial activities, including the sale of the individual specification products extracted in our natural gas processing assets (sale of specification NGL products component of the frac spread), as well as other net sales of NGL inventory, held mainly at our owned NGL storage terminals. Our objectives for these derivatives include hedging anticipated purchases and sales and stored inventory. We manage these exposures with various instruments including futures, forwards, swaps and options.

See Note 7 to our Condensed Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

The fair value of our commodity derivatives and the change in fair value as of March 31, 2024 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil	$ (10)	$ (39)	$ 40
Natural gas	(50)	$ 10	$ (10)
NGL and other	(77)	$ (51)	$ 51
Total fair value	$ (137)		

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term commodity prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

Interest Rate Risk

Debt. Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time, we use interest rate derivatives to hedge interest rate risk associated with anticipated interest payments and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus are not subject to interest rate risk. Our variable rate debt outstanding at March 31, 2024, approximately $540 million, was subject to interest rate resets that generally range from less than one week to approximately one month. The average interest rate on variable rate debt that was outstanding during the three months ended March 31, 2024 was 5.8%, based upon rates in effect during such period. The fair value of our interest rate derivatives was a net asset of $68 million as of March 31, 2024. A 10% increase in the forward SOFR curve as of March 31, 2024 would have resulted in an increase of $18 million to the fair value of our interest rate derivatives. A 10% decrease in the forward SOFR curve as of March 31, 2024 would have resulted in a decrease of $18 million to the fair value of our interest rate derivatives. See Note 7 to our Condensed Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Series B Preferred Units. Distributions on the Series B preferred units accumulate and are payable quarterly in arrears on the 15th day of February, May, August and November. Distributions on the Series B preferred units accumulate based on the applicable three-month SOFR, plus certain adjustments. Based upon the Series B preferred units outstanding at March 31, 2024 and the liquidation preference of $1,000 per unit, a change of 100 basis points in interest rates would increase or decrease the annual distributions on the Series B preferred units by approximately $8 million. See Note 11 to our Consolidated Financial Statements included in Part IV of our 2023 Annual Report on Form 10-K for additional information regarding our Series B preferred unit distributions.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our "DCP." Our DCP is designed to ensure that information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the "Exchange Act") is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our DCP as of March 31, 2024, the end of the period covered by this report, and, based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our DCP is effective.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting during the first quarter of 2024 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included in Note 9 to our Condensed Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

For a discussion of our risk factors, see Item 1A. of our 2023 Annual Report on Form 10-K. Those risks and uncertainties are not the only ones facing us and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Item 5. OTHER INFORMATION

During the quarter ended March 31, 2024, none of our directors or officers (as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934) adopted or terminated a Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement (as such terms are defined in Item 408 of Regulation S-K).

Item 6. EXHIBITS

Exhibit No.		Description
3.1	—	Seventh Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of October 10, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 12, 2017).
3.2	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	—	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.4	—	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.5	—	Amendment No. 3 dated June 30, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.7 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.6	—	Amendment No. 4 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P (incorporated by reference to Exhibit 3.8 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.7	—	Amendment No. 5 dated December 1, 2019 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.7 to our Annual Report on Form 10-K for the year ended December, 31, 2019).
3.8	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	—	Amendment No. 1 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.10	—	Seventh Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated November 15, 2016 (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed November 21, 2016).
3.11	—	Eighth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated November 15, 2016 (incorporated by reference to Exhibit 3.4 to our Current Report on Form 8-K filed November 21, 2016).
3.12	—	Amendment No. 1 dated September 26, 2018 to the Eighth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 2, 2018).
3.13	—	Amendment No. 2 dated May 23, 2019 to the Eighth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed May 30, 2019).
3.14	—	Amendment No. 3 dated August 17, 2023 to the Eighth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed August 21, 2023).
3.15	—	Certificate of Incorporation of PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2006).

3.16	—	Bylaws of PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to our Annual Report on Form 10-K for the year ended December 31, 2006).
3.17	—	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed January 4, 2008).
3.18	—	Certificate of Limited Partnership of Plains GP Holdings, L.P. (incorporated by reference to Exhibit 3.1 to PAGP's Registration Statement on Form S-1 (333-190227) filed July 29, 2013).
3.19	—	Second Amended and Restated Agreement of Limited Partnership of Plains GP Holdings, L.P. dated November 15, 2016 (incorporated by reference to Exhibit 3.2 to PAGP's Current Report on Form 8-K filed November 21, 2016).
3.20	—	Amendment No. 1 dated April 6, 2020 to the Second Amended and Restated Agreement of Limited Partnership of Plains GP Holdings, L.P. (incorporated by reference to Exhibit 3.1 to PAGP's Current Report on Form 8-K filed April 9, 2020).
3.21	—	Certificate of Formation of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.3 to PAGP's Registration Statement on Form S-1 (333-190227) filed July 29, 2013).
3.22	—	Fourth Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC dated effective as of August 19, 2021 (incorporated by reference to Exhibit 3.21 to our Annual Report on Form 10-K for the year ended December 31, 2021).
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	—	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed May 12, 2006).
4.3	—	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed October 30, 2006).
4.4	—	Twenty-First Supplemental Indenture (5.15% Senior Notes due 2042) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed March 26, 2012).
4.5	—	Twenty-Third Supplemental Indenture (4.30% Senior Notes due 2043) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 12, 2012).
4.6	—	Twenty-Fifth Supplemental Indenture (4.70% Senior Notes due 2044) dated April 23, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 29, 2014).
4.7	—	Twenty-Sixth Supplemental Indenture (3.60% Senior Notes due 2024) dated September 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 11, 2014).
4.8	—	Twenty-Eighth Supplemental Indenture (4.90% Senior Notes due 2045) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 11, 2014).

4.9	—	Twenty-Ninth Supplemental Indenture (4.65% Senior Notes due 2025) dated August 24, 2015, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 26, 2015).
4.10	—	Thirtieth Supplemental Indenture (4.50% Senior Notes due 2026) dated November 22, 2016, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed November 29, 2016).
4.11	—	Thirty-First Supplemental Indenture (3.55% Senior Notes due 2029) dated September 16, 2019, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 17, 2019).
4.12	—	Thirty-Second Supplemental Indenture (3.80% Senior Notes due 2030) dated June 11, 2020, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed June 11, 2020).
4.13	—	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to our Registration Statement on Form S-3, File No. 333-162477).
4.14	—	Registration Rights Agreement dated as of January 28, 2016 among Plains All American Pipeline, L.P. and the Purchasers named therein (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed February 2, 2016).
4.15	—	Registration Rights Agreement by and among Plains All American Pipeline, L.P. and the Holders defined therein, dated November 15, 2016 (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed November 21, 2016).
4.16	—	Description of Our Securities (incorporated by reference to Exhibit 4.16 to our Annual Report on Form 10-K for the year ended December 31, 2023).
31.1 †	—	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2 †	—	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1 ††	—	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.
32.2 ††	—	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.
101.INS†	—	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH†	—	Inline XBRL Taxonomy Extension Schema Document
101.CAL†	—	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	—	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	—	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE†	—	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104†	—	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

† Filed herewith.

†† Furnished herewith.

* Management compensatory plan or arrangement.

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.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PAA GP LLC,
its general partner

By: Plains AAP, L.P.,
its sole member

By: Plains All American GP LLC,
its general partner

By: /s/ Willie Chiang
Willie Chiang,
Chief Executive Officer of Plains All American GP LLC
(Principal Executive Officer)

May 9, 2024

By: /s/ Al Swanson
Al Swanson,
Executive Vice President and Chief Financial Officer of Plains All American GP LLC
(Principal Financial Officer)

May 9, 2024

By: /s/ Chris Herbold
Chris Herbold,
Senior Vice President, Finance and Chief Accounting Officer of Plains All American GP LLC
(Principal Accounting Officer)

May 9, 2024

EXHIBIT 31.1

CERTIFICATION

I, Willie Chiang, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P. (the "registrant");

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

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

4. The registrant's other certifying officer(s) 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(s) 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: May 9, 2024

/s/ Willie Chiang
Willie Chiang
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Al Swanson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P. (the “registrant”);

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

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

4. The registrant’s other certifying officer(s) 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(s) 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: May 9, 2024

/s/ Al Swanson

Al Swanson
Chief Financial Officer

EXHIBIT 32.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350**

I, Willie Chiang, Chief Executive Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended March 31, 2024 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ Willie Chiang

Name: Willie Chiang
Date: May 9, 2024

EXHIBIT 32.2

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350**

I, Al Swanson, Chief Financial Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended March 31, 2024 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ Al Swanson

Name: Al Swanson
Date: May 9, 2024