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 June 30, 2023

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 July 31, 2023, there were 698,390,006 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)

	June 30, 2023	December 31, 2022
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 933	$ 401
Trade accounts receivable and other receivables, net	3,220	3,907
Inventory	367	729
Other current assets	137	318
Total current assets	4,657	5,355
PROPERTY AND EQUIPMENT	20,362	20,020
Accumulated depreciation	(5,141)	(4,770)
Property and equipment, net	15,221	15,250
OTHER ASSETS		
Investments in unconsolidated entities	3,062	3,084
Intangible assets, net	1,999	2,145
Linefill	966	961
Long-term operating lease right-of-use assets, net	339	349
Long-term inventory	270	284
Other long-term assets, net	386	464
Total assets	$ 26,900	$ 27,892
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Trade accounts payable	$ 3,295	$ 4,044
Short-term debt	709	1,159
Other current liabilities	648	688
Total current liabilities	4,652	5,891
LONG-TERM LIABILITIES		
Senior notes, net	7,239	7,237
Other long-term debt, net	49	50
Long-term operating lease liabilities	299	308
Other long-term liabilities and deferred credits	1,059	1,081
Total long-term liabilities	8,646	8,676
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
PARTNERS' CAPITAL		
Series A preferred unitholders (71,090,468 and 71,090,468 units outstanding, respectively)	1,507	1,505
Series B preferred unitholders (800,000 and 800,000 units outstanding, respectively)	787	787
Common unitholders (698,390,006 and 698,354,498 units outstanding, respectively)	8,085	7,765
Total partners' capital excluding noncontrolling interests	10,379	10,057
Noncontrolling interests	3,223	3,268
Total partners' capital	13,602	13,325
Total liabilities and partners' capital	$ 26,900	$ 27,892

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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(unaudited)		(unaudited)	
REVENUES				
Product sales revenues	$ 11,201	$ 16,007	$ 23,145	$ 29,388
Services revenues	401	352	798	665
Total revenues	11,602	16,359	23,943	30,053
COSTS AND EXPENSES				
Purchases and related costs	10,544	15,324	21,867	28,109
Field operating costs	333	307	690	653
General and administrative expenses	85	78	171	160
Depreciation and amortization	259	242	515	473
(Gains)/losses on asset sales and asset impairments, net	3	(3)	(150)	(46)
Total costs and expenses	11,224	15,948	23,093	29,349
OPERATING INCOME	378	411	850	704
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	89	104	178	201
Interest expense (net of capitalized interest of $3, $1, $5, and $2, respectively)	(95)	(99)	(193)	(206)
Other income/(expense), net	20	(118)	85	(155)
INCOME BEFORE TAX	392	298	920	544
Current income tax expense	(20)	(30)	(81)	(48)
Deferred income tax expense	(23)	(17)	(15)	(20)
NET INCOME	349	251	824	476
Net income attributable to noncontrolling interests	(56)	(48)	(109)	(86)
NET INCOME ATTRIBUTABLE TO PAA	$ 293	$ 203	$ 715	$ 390
NET INCOME PER COMMON UNIT (NOTE 3):				
Net income allocated to common unitholders — Basic and Diluted	$ 227	$ 153	$ 588	$ 290
Basic and diluted weighted average common units outstanding	698	702	698	703
Basic and diluted net income per common unit	$ 0.32	$ 0.22	$ 0.84	$ 0.41

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/(LOSS)
(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(unaudited)		(unaudited)	
Net income	$ 349	$ 251	$ 824	$ 476
Other comprehensive income/(loss)	85	(52)	85	22
Comprehensive income	434	199	909	498
Comprehensive income attributable to noncontrolling interests	(56)	(48)	(109)	(86)
Comprehensive income attributable to PAA	$ 378	$ 151	$ 800	$ 412

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	Other	Total
		(unaudited)		
Balance at December 31, 2022	$ (107)	$ (846)	$ (1)	$ (954)
Reclassification adjustments	5	—	—	5
Unrealized gain on hedges	2	—	—	2
Currency translation adjustments	—	77	—	77
Other	—	—	1	1
Total period activity	7	77	1	85
Balance at June 30, 2023	$ (100)	$ (769)	$ —	$ (869)

	Derivative Instruments	Translation Adjustments	Other	Total
		(unaudited)		
Balance at December 31, 2021	$ (208)	$ (642)	$ (3)	$ (853)
Reclassification adjustments	6	—	—	6
Unrealized gain on hedges	68	—	—	68
Currency translation adjustments	—	(50)	—	(50)
Other	—	—	(2)	(2)
Total period activity	74	(50)	(2)	22
Balance at June 30, 2022	$ (134)	$ (692)	$ (5)	$ (831)

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)

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 824	$ 476
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	515	473
Gains on asset sales and asset impairments, net	(150)	(46)
Deferred income tax expense	15	20
Gains on sales of linefill	(2)	(30)
Loss on foreign currency revaluation	1	10
Settlement of terminated interest rate hedging instruments (Note 7)	80	—
Change in fair value of Preferred Distribution Rate Reset Option (Note 7)	(58)	147
Equity earnings in unconsolidated entities	(178)	(201)
Distributions on earnings from unconsolidated entities	219	224
Other	36	27
Changes in assets and liabilities, net of acquisitions	329	32
Net cash provided by operating activities	1,631	1,132
CASH FLOWS FROM INVESTING ACTIVITIES		
Investments in unconsolidated entities	(19)	(4)
Additions to property, equipment and other	(267)	(190)
Cash paid for purchases of linefill	(14)	(60)
Proceeds from sales of assets	284	57
Cash received from sales of linefill	9	61
Other investing activities	1	13
Net cash used in investing activities	(6)	(123)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings under commercial paper program (Note 5)	—	115
Repayments of senior notes (Note 5)	(400)	(750)
Repurchase of common units	—	(74)
Distributions paid to Series A preferred unitholders (Note 6)	(79)	(74)
Distributions paid to Series B preferred unitholders (Note 6)	(36)	(25)
Distributions paid to common unitholders (Note 6)	(374)	(280)
Distributions paid to noncontrolling interests (Note 6)	(151)	(121)
Other financing activities	(61)	13
Net cash used in financing activities	(1,101)	(1,196)
Effect of translation adjustment	8	1
Net increase/(decrease) in cash and cash equivalents and restricted cash	532	(186)
Cash and cash equivalents and restricted cash, beginning of period	401	453
Cash and cash equivalents and restricted cash, end of period	$ 933	$ 267
Cash paid for:		
Interest, net of amounts capitalized	$ 188	$ 201
Income taxes, net of amounts refunded	$ 8	$ 39

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					
	Preferred Unitholders					
	Series A	Series B	Common Unitholders	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	(unaudited)					
Balance at December 31, 2022	$ 1,505	$ 787	$ 7,765	$ 10,057	$ 3,268	$ 13,325
Net income	85	36	594	715	109	824
Distributions (Note 6)	(85)	(36)	(374)	(495)	(151)	(646)
Other comprehensive income	—	—	85	85	—	85
Other	2	—	15	17	(3)	14
Balance at June 30, 2023	$ 1,507	$ 787	$ 8,085	$ 10,379	$ 3,223	$ 13,602

	Limited Partners					
	Preferred Unitholders					
	Series A	Series B	Common Unitholders	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	(unaudited)					
Balance at March 31, 2023	$ 1,506	$ 787	$ 7,950	$ 10,243	$ 3,240	$ 13,483
Net income	44	18	231	293	56	349
Distributions (Note 6)	(44)	(18)	(187)	(249)	(73)	(322)
Other comprehensive income	—	—	85	85	—	85
Other	1	—	6	7	—	7
Balance at June 30, 2023	$ 1,507	$ 787	$ 8,085	$ 10,379	$ 3,223	$ 13,602

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(continued)
(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, 2021	$ 1,505	$ 787	$ 7,680	$ 9,972	$ 2,838	$ 12,810
Net income	74	25	291	390	86	476
Distributions	(74)	(25)	(280)	(379)	(121)	(500)
Other comprehensive income	—	—	22	22	—	22
Repurchase of common units	—	—	(74)	(74)	—	(74)
Other	—	—	—	—	(15)	(15)
Balance at June 30, 2022	$ 1,505	$ 787	$ 7,639	$ 9,931	$ 2,788	$ 12,719

	Limited Partners			Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Preferred Unitholders		Common Unitholders			
	Series A	Series B				
	(unaudited)					
Balance at March 31, 2022	$ 1,505	$ 787	$ 7,751	$ 10,043	$ 2,811	$ 12,854
Net income	37	12	154	203	48	251
Distributions	(37)	(12)	(153)	(202)	(62)	(264)
Other comprehensive loss	—	—	(52)	(52)	—	(52)
Repurchase of common units	—	—	(49)	(49)	—	(49)
Other	—	—	(12)	(12)	(9)	(21)
Balance at June 30, 2022	$ 1,505	$ 787	$ 7,639	$ 9,931	$ 2,788	$ 12,719

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 June 30, 2023, AAP also owned a limited partner interest in us through its ownership of approximately 240.8 million of our common units (approximately 31% 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 June 30, 2023, owned an approximate 81% 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 2022 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, 2022 was derived from audited financial statements, but does not include all disclosures required by GAAP. The results of operations for the three and six months ended June 30, 2023 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, and certain reclassifications have been made to information from previous years to conform to the current presentation.

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

Except as discussed in our 2022 Annual Report on Form 10-K, there have been no new accounting pronouncements that have become effective or have been issued during the six months ended June 30, 2023 that are of significance or potential significance to us.

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 2022 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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Crude Oil segment revenues from contracts with customers				
Sales	$ 10,937	$ 15,576	$ 22,318	$ 28,433
Transportation	255	175	505	330
Terminalling, Storage and Other	94	90	185	180
Total Crude Oil segment revenues from contracts with customers	$ 11,286	$ 15,841	$ 23,008	$ 28,943

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
NGL segment revenues from contracts with customers				
Sales	$ 232	$ 499	$ 885	$ 1,344
Transportation	8	7	15	16
Terminalling, Storage and Other	23	20	52	45
Total NGL segment revenues from contracts with customers	$ 263	$ 526	$ 952	$ 1,405

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 June 30, 2023	Crude Oil	NGL	Total
Revenues from contracts with customers	$ 11,286	$ 263	$ 11,549
Other revenues	9	118	127
Total revenues of reportable segments	$ 11,295	$ 381	$ 11,676
Intersegment revenues elimination			(74)
Total revenues			$ 11,602

Three Months Ended June 30, 2022	Crude Oil	NGL	Total
Revenues from contracts with customers	$ 15,841	$ 526	$ 16,367
Other revenues	99	44	143
Total revenues of reportable segments	$ 15,940	$ 570	$ 16,510
Intersegment revenues elimination			(151)
Total revenues			$ 16,359

Six Months Ended June 30, 2023	Crude Oil	NGL	Total
Revenues from contracts with customers	$ 23,008	$ 952	$ 23,960
Other items in revenues	45	119	164
Total revenues of reportable segments	$ 23,053	$ 1,071	$ 24,124
Intersegment revenues			(181)
Total revenues			$ 23,943

Six Months Ended June 30, 2022	Crude Oil	NGL	Total
Revenues from contracts with customers	$ 28,943	$ 1,405	$ 30,348
Other items in revenues	76	(101)	(25)
Total revenues of reportable segments	$ 29,019	$ 1,304	$ 30,323
Intersegment revenues			(270)
Total revenues			$ 30,053

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	June 30, 2023	December 31, 2022
Billed and collected	Other current liabilities	$ 79	$ 104
Unbilled [(1)]	N/A	1	1
Total		$ 80	$ 105

(1) Amounts were related to deficiencies for which the counterparties had not met their contractual minimum commitments and are not reflected in our Condensed Consolidated Financial Statements as we had not yet billed or collected such amounts.

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, 2022	$ 229
Amounts recognized as revenue	(35)
Additions	20
Other	2
Balance at June 30, 2023	$ 216

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 June 30, 2023 (in millions):

	Remainder of 2023	2024	2025	2026	2027	2028 and Thereafter
Pipeline revenues supported by minimum volume commitments and capacity agreements [1]	$ 182	$ 360	$ 391	$ 140	$ 101	$ 240
Terminalling, storage and other agreement revenues	137	217	134	106	96	771
Total	$ 319	$ 577	$ 525	$ 246	$ 197	$ 1,011

(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

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL. These purchasers include, but are not limited to, refiners, producers, marketing and trading companies and financial institutions. The majority of our accounts receivable relate to our crude oil merchant activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

To mitigate credit risk related to our accounts receivable, we utilize a rigorous credit review process. We closely monitor market conditions and perform credit reviews of each customer to make a determination with respect to the amount, if any, of open credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of advance cash payments, standby letters of credit, credit insurance or parental guarantees. Additionally, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. For a majority of these net-cash arrangements, we also enter into netting agreements (contractual agreements that allow us to offset receivables and payables with those counterparties against each other on our balance sheet).

Accounts receivable from the sale of crude oil are generally settled with counterparties on the industry settlement date, which is typically in the month following the month in which the title transfers. Otherwise, we generally invoice customers within 30 days of when the products or services were provided and generally require payment within 30 days of the invoice date. We review all outstanding accounts receivable balances on a monthly basis and record our receivables net of expected credit losses. We do not write-off accounts receivable balances until we have exhausted substantially all collection efforts. At June 30, 2023 and December 31, 2022, 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):

	June 30, 2023	December 31, 2022
Trade accounts receivable arising from revenues from contracts with customers	$ 3,607	$ 4,141
Other trade accounts receivables and other receivables [1]	5,926	7,216
Impact due to contractual rights of offset with counterparties	(6,313)	(7,450)
Trade accounts receivable and other receivables, net	$ 3,220	$ 3,907

(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 12 and Note 18 to our Consolidated Financial Statements included in Part IV of our 2022 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 and six months ended June 30, 2023 and 2022 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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Basic and Diluted Net Income per Common Unit				
Net income attributable to PAA	$ 293	$ 203	$ 715	$ 390
Distributions to Series A preferred unitholders	(44)	(37)	(85)	(74)
Distributions to Series B preferred unitholders	(18)	(12)	(36)	(25)
Amounts allocated to participating securities	(5)	(1)	(8)	(1)
Other	1	—	2	—
Net income allocated to common unitholders [1]	$ 227	$ 153	$ 588	$ 290
Basic and diluted weighted average common units outstanding	698	702	698	703
Basic and diluted net income per common unit	$ 0.32	$ 0.22	$ 0.84	$ 0.41

(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):

	June 30, 2023				December 31, 2022			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]
Inventory								
Crude oil	3,150	barrels	$ 213	$ 67.62	6,713	barrels	$ 452	$ 67.33
NGL	5,084	barrels	144	$ 28.32	7,285	barrels	270	$ 37.06
Other	N/A		10	N/A	N/A		7	N/A
Inventory subtotal			367				729	
Linefill								
Crude oil	15,226	barrels	898	$ 58.98	15,480	barrels	906	$ 58.53
NGL	2,168	barrels	68	$ 31.37	1,876	barrels	55	$ 29.32
Linefill subtotal			966				961	
Long-term inventory								
Crude oil	3,254	barrels	224	$ 68.84	3,102	barrels	246	$ 79.30
NGL	1,327	barrels	46	$ 34.66	1,066	barrels	38	$ 35.65
Long-term inventory subtotal			270				284	
Total			$ 1,603				$ 1,974	

(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):

	June 30, 2023	December 31, 2022
SHORT-TERM DEBT		
Senior notes:		
2.85% senior notes due January 2023 [1]	$ —	$ 400
3.85% senior notes due October 2023	700	700
Other	9	59
Total short-term debt	709	1,159
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $44 and $46, respectively	7,239	7,237
Other	49	50
Total long-term debt	7,288	7,287
Total debt [2]	$ 7,997	$ 8,446

(1) These senior notes were redeemed on January 31, 2023.

(2) Our fixed-rate senior notes had a face value of approximately $8.0 billion and $8.4 billion as of June 30, 2023 and December 31, 2022, respectively. We estimated the aggregate fair value of these notes as of June 30, 2023 and December 31, 2022 to be approximately $7.3 billion and $7.6 billion, respectively. 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. The fair value estimate for our senior notes is based upon observable market data and is classified in Level 2 of the fair value hierarchy.

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the six months ended June 30, 2023 and 2022 were approximately $1.5 billion and $16.4 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $1.5 billion and $16.3 billion for the six months ended June 30, 2023 and 2022, 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.

On January 31, 2023, we redeemed our 2.85%, $400 million senior notes due January 2023.

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 June 30, 2023 and December 31, 2022, we had outstanding letters of credit of $127 million and $102 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, 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 and June 30, 2023	71,090,468	800,000	698,390,006

	Limited Partners		
	Series A Preferred Units	**Series B Preferred Units**	**Common Units**
Outstanding at December 31, 2021	71,090,468	800,000	704,991,540
Repurchase and cancellation of common units under the Common Equity Repurchase Program	—	—	(2,375,299)
Issuances of common units under equity-indexed compensation plans	—	—	51,937
Outstanding at March 31, 2022	71,090,468	800,000	702,668,178
Repurchase and cancellation of common units under the Common Equity Repurchase Program	—	—	(4,876,062)
Issuances of common units under equity-indexed compensation plans	—	—	147,830
Outstanding at June 30, 2022	71,090,468	800,000	697,939,946

Distributions

Series A Preferred Unit Distributions. After the fifth anniversary of the January 28, 2016 issuance date of our Series A preferred units, the holders of our Series A preferred units, acting by majority vote, had the option to make a one-time election to reset the Series A preferred unit distribution rate to equal the then applicable rate of ten-year U.S. Treasury Securities plus 5.85% (the "Preferred Distribution Rate Reset Option"). In January 2023, the Series A preferred unitholders elected the Preferred Distribution Rate Reset Option which resulted in an increase in the quarterly distribution rate to approximately \$0.615 per unit. This new distribution rate was effective on January 31, 2023. The quarterly distribution paid in May 2023 reflected a pro-rated amount of approximately \$0.585 per unit. The following table details distributions to our Series A preferred unitholders paid during or pertaining to the first six months of 2023 (in millions, except per unit data):

	Series A Preferred Unitholders	
Distribution Payment Date	**Cash Distribution**	**Distribution per Unit**
August 14, 2023 [(1)]	$ 44	$ 0.615
May 15, 2023	$ 42	$ 0.585
February 14, 2023	$ 37	$ 0.525

(1) Payable to unitholders of record at the close of business on July 31, 2023 for the period from April 1, 2023 through June 30, 2023. At June 30, 2023, 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 12 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for additional information regarding our 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
August 15, 2023 [(1)]	$ 19	$ 24.10
May 15, 2023	$ 18	$ 22.18
February 15, 2023	$ 18	$ 22.27

(1) Payable to unitholders of record at the close of business on August 1, 2023 for the period from May 15, 2023 through August 14, 2023. At June 30, 2023, 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 six months of 2023 (in millions, except per unit data):

	Distributions			
	Common Unitholders			
Distribution Payment Date	Public	AAP	Total Cash Distribution	Cash Distribution per Common Unit
August 14, 2023 [(1)]	$ 123	$ 64	$ 187	$ 0.2675
May 15, 2023	$ 122	$ 65	$ 187	$ 0.2675
February 14, 2023	$ 122	$ 65	$ 187	$ 0.2675

(1) Payable to unitholders of record at the close of business on July 31, 2023 for the period from April 1, 2023 through June 30, 2023.

Noncontrolling Interests in Subsidiaries

As of June 30, 2023, 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”).

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Permian JV	$ 53	$ 58	$ 111	$ 112
Cactus II [(1)]	15	—	29	—
Red River	5	4	11	9
	$ 73	$ 62	$ 151	$ 121

(1) In November 2022, we acquired an additional interest in Cactus II which, combined with changes in the governance of this entity, resulted in our obtaining control of the entity. Subsequent to this transaction, we reflect Cactus II as a consolidated subsidiary. See Note 7 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for additional information on the Cactus II transaction.

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 June 30, 2023 and December 31, 2022, 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 June 30, 2023, net derivative positions related to these activities included:

- A net long position of 5.0 million barrels associated with our crude oil purchases, which was unwound ratably during July 2023 to match monthly average pricing.
- A net short time spread position of 6.1 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through October 2024.
- A net crude oil basis spread position of 1.9 million barrels at multiple locations through November 2024. These derivatives allow us to lock in grade and location basis differentials.
- A net short position of 10.5 million barrels through June 2024 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 June 30, 2023:

	Notional Volume (Short)/Long	Remaining Tenor
Natural gas purchases	38.9 Bcf	December 2023
Propane sales	(7.5) MMbls	December 2023
Butane sales	(0.9) MMbls	December 2023
Condensate sales	(0.5) MMbls	December 2023
Fuel gas requirements [(1)]	4.4 Bcf	June 2024
Power supply requirements [(1)]	2.2 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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Product sales revenues	$ 119	$ 76	$ 118	$ (136)
Field operating costs	6	8	(13)	21
Net gain/ (loss) from commodity derivative activity	$ 125	$ 84	$ 105	$ (115)

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):

	June 30, 2023	December 31, 2022
Initial margin	$ 46	$ 93
Variation margin returned	(177)	(236)
Letters of credit	(25)	(25)
Net broker payable	$ (156)	$ (168)

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.

	June 30, 2023				December 31, 2022			
	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	$ 221	$ (21)	$ (156)	$ 44	$ 300	$ (71)	$ (168)	$ 61
Other long-term assets, net	3	—	—	3	9	(5)	—	4
Derivative Liabilities								
Other current liabilities	—	(33)	—	(33)	2	(13)	—	(11)
Other long-term liabilities and deferred credits	2	(9)	—	(7)	—	—	—	—
Total	$ 226	$ (63)	$ (156)	$ 7	$ 311	$ (89)	$ (168)	$ 54

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 June 30, 2023 (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

During the three months ended June 30, 2023, we terminated $200 million of notional interest hedging instruments previously expected to terminate in June 2023 for proceeds of $80 million, of which $73 million was recorded in AOCI. As of June 30, 2023, there was a net loss of $100 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 June 30, 2023; 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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Interest rate derivatives, net	$ 8	$ 36	$ 2	$ 68

At June 30, 2023, the net fair value of our interest rate hedges, which were included in “Other current assets” and “Other long-term liabilities and deferred credits” on our Condensed Consolidated Balance Sheet, totaled $47 million and $5 million, respectively. At December 31, 2022, the net fair value of these hedges totaled $75 million and $45 million, which were included in “Other current assets” and “Other long-term assets, net,” respectively.

Preferred Distribution Rate Reset Option

In January 2023, we received notice that the Series A preferred unitholders elected the Preferred Distribution Rate Reset Option. Prior to this election, the Preferred Distribution Rate Reset Option was accounted for as an embedded derivative. A derivative feature embedded in a contract that does not meet the definition of a derivative in its entirety must be bifurcated and accounted for separately if the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract. The Preferred Distribution Rate Reset Option embedded derivative was required to be bifurcated from the related host contract, our partnership agreement, and recorded at fair value on our Condensed Consolidated Balance Sheet. The fair value of the Preferred Distribution Rate Reset Option, which was included in “Other long-term liabilities and deferred credits” on our Condensed Consolidated Balance Sheet, totaled $189 million at December 31, 2022. The Preferred Distribution Rate Reset Option was settled when we received notice that the Series A preferred unitholders elected the Preferred Distribution Rate Reset Option. The fair value of the Preferred Distribution Rate Reset Option on the settlement date was $131 million. The Preferred Distribution Rate Reset Option embedded derivative was not designated in a hedging relationship for accounting purposes and corresponding changes in fair value were recognized in “Other income/(expense), net” in our Condensed Consolidated Statements of Operations. For the three months ended June 30, 2022, we recognized a loss of $103 million. For the six months ended June 30, 2023 and 2022, we recognized a gain of $58 million and a net loss of $147 million, respectively. See Note 6 for additional information regarding the Preferred Distribution Rate Reset Option.

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 June 30, 2023				Fair Value as of December 31, 2022			
Recurring Fair Value Measures [1]	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 9	$ 154	$ —	$ 163	$ (7)	$ 229	$ —	$ 222
Interest rate derivatives	—	42	—	42	—	120	—	120
Preferred Distribution Rate Reset Option	—	—	—	—	—	—	(189)	(189)
Total net derivative asset/(liability)	$ 9	$ 196	$ —	$ 205	$ (7)	$ 349	$ (189)	$ 153

(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.

Level 3

Level 3 of the fair value hierarchy includes the Preferred Distribution Rate Reset Option contained in our partnership agreement which was classified as an embedded derivative. As discussed above, the Preferred Distribution Rate Reset Option was settled on January 31, 2023. The fair value of the Preferred Distribution Rate Reset Option was based on a Monte Carlo valuation model that estimated the fair value of the Series A preferred units with and without the Preferred Distribution Rate Reset Option. This model relied on assumptions for forecasts for the ten-year U.S. Treasury rate, our common unit price, and default probabilities which impacted timing estimates as to when the option would be exercised.

Rollforward of Level 3 Net Asset/(Liability)

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives classified as Level 3 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Beginning Balance	$ —	$ (44)	$ (189)	$ (2)
Net gains/(losses) for the period included in earnings	—	(103)	58	(147)
Settlements	—	—	131	2
Ending Balance	$ —	$ (147)	$ —	$ (147)
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	$ —	$ (103)	$ —	$ (147)

Note 8—Related Party Transactions

See Note 17 to our Consolidated Financial Statements included in Part IV of our 2022 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 $10 million as of June 30, 2023. Interest income/expense on the related party notes totaled $7 million and $10 million for the three and six months ended June 30, 2023, respectively.

As of June 30, 2023, our outstanding related party note receivable and related party note payable balances were as follows (in millions):

	June 30, 2023
Related party note receivable (1)	$ 378
Related party note payable (1)	$ 378

(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 and six months ended June 30, 2023 and 2022, 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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Revenues from related parties	$ 12	$ 10	$ 23	$ 22
Purchases and related costs from related parties	$ 101	$ 87	$ 200	$ 184

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

	June 30, 2023	December 31, 2022
Trade accounts receivable and other receivables, net from related parties [(1)]	$ 76	$ 45
Trade accounts payable to related parties [(1)] [(2)]	$ 72	$ 79

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

(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 both June 30, 2023 and December 31, 2022, our estimated undiscounted reserve for environmental liabilities (excluding liabilities related to the Line 901 incident, as discussed further below) totaled $55 million, of which $10 million was classified as short-term and $45 million was classified as long-term for each period. 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 June 30, 2023 and December 31, 2022, 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, $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 filed in the United States District Court for the Central District of California that was remanded to the 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; (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, 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. 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. Nine class action lawsuits were filed against us; however, after various claims were either dismissed or consolidated, two proceedings remained pending in the United States District Court for the Central District of California.

In the first proceeding, the 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 joined this proceeding as a co-defendant with respect to its interest in such acquired pipelines.

In the second proceeding, 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. 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 June 30, 2023. Insurers responsible for $185 million of the remaining $225 million of coverage 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 responded to our reimbursement demand. We have initiated arbitration proceedings against the insurers responsible for $175 million of coverage and intend to vigorously pursue recovery from our insurers of all amounts for which we have claimed 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 and the Derivative 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 June 30, 2023, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $740 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 the Derivative 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.

During the six months ended June 30, 2022, we recognized costs, net of amounts probable of recovery from insurance carriers, of $85 million. We did not recognize any such costs during the six months ended June 30, 2023. As of June 30, 2023, we had a remaining undiscounted gross liability of approximately $98 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 June 30, 2023, 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 $240 million. Through June 30, 2023, 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 June 30, 2023, 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.

Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident, natural disaster, terrorist attack, cyber event or other event. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. We maintain various types and varying levels of insurance coverage to cover our operations and properties, and we self-insure certain risks, including gradual pollution, cybersecurity and named windstorms. To the extent we do maintain insurance coverage, such insurance does not cover every potential risk that might occur, associated with operating pipelines, terminals and other facilities and equipment, including the potential loss of significant revenues and cash flows.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its insurance or indemnification obligations, could materially and adversely affect our operations and financial condition. While we strive to maintain adequate insurance coverage, our actual costs may exceed our coverage levels and insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our assets and operations. With respect to our insurance coverage, our policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Additionally, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable. As a result, we may elect to self-insure or utilize higher deductibles in certain other insurance programs. In addition, although we believe that we have established adequate reserves and liquidity to the extent such risks are not insured, costs incurred in excess of these reserves may be higher or we may not receive insurance proceeds in a timely manner, which may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Note 10—Segment Information

We manage our operations through two operating segments, which are also our reportable segments: Crude Oil and NGL. See Note 20 to our Consolidated Financial Statements included in Part IV of our 2022 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 ("Adjusted EBITDA attributable to noncontrolling interests").

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

	Crude Oil	NGL	Intersegment Revenues Elimination	Total
Three Months Ended June 30, 2023				
Revenues [1]:				
Product sales	$ 10,925	$ 346	$ (70)	$ 11,201
Services	370	35	(4)	401
Total revenues	$ 11,295	$ 381	$ (74)	$ 11,602
Equity earnings in unconsolidated entities	$ 89	$ —		$ 89
Segment Adjusted EBITDA	$ 529	$ 62		$ 591
Maintenance capital expenditures	$ 36	$ 26		$ 62
Three Months Ended June 30, 2022				
Revenues [1]:				
Product sales	$ 15,625	$ 525	$ (143)	$ 16,007
Services	315	45	(8)	352
Total revenues	$ 15,940	$ 570	$ (151)	$ 16,359
Equity earnings in unconsolidated entities	$ 104	$ —		$ 104
Segment Adjusted EBITDA	$ 494	$ 120		$ 614
Maintenance capital expenditures	$ 25	$ 18		$ 43
Six Months Ended June 30, 2023				
Revenues [1]:				
Product sales	$ 22,333	$ 982	$ (170)	$ 23,145
Services	720	89	(11)	798
Total revenues	$ 23,053	$ 1,071	$ (181)	$ 23,943
Equity earnings in unconsolidated entities	$ 178	$ —		$ 178
Segment Adjusted EBITDA	$ 1,046	$ 254		$ 1,300
Maintenance capital expenditures	$ 67	$ 42		$ 109
Six Months Ended June 30, 2022				
Revenues [1]:				
Product sales	$ 28,435	$ 1,207	$ (254)	$ 29,388
Services	584	97	(16)	665
Total revenues	$ 29,019	$ 1,304	$ (270)	$ 30,053
Equity earnings in unconsolidated entities	$ 201	$ —		$ 201
Segment Adjusted EBITDA	$ 946	$ 281		$ 1,227
Maintenance capital expenditures	$ 45	$ 25		$ 70

(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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Segment Adjusted EBITDA	$ 591	$ 614	$ 1,300	$ 1,227
Adjustments: [(1)]				
Depreciation and amortization of unconsolidated entities [(2)]	(24)	(17)	(47)	(37)
Derivative activities and inventory valuation adjustments [(3)]	86	75	(6)	(13)
Long-term inventory costing adjustments [(4)]	(2)	13	(31)	105
Deficiencies under minimum volume commitments, net [(5)]	2	(10)	9	(15)
Equity-indexed compensation expense [(6)]	(8)	(7)	(17)	(15)
Foreign currency revaluation [(7)]	(19)	(3)	(15)	(1)
Line 901 incident [(8)]	—	—	—	(85)
Adjusted EBITDA attributable to noncontrolling interests [(9)]	103	89	200	166
Depreciation and amortization	(259)	(242)	(515)	(473)
Gains/(losses) on asset sales and asset impairments, net	(3)	3	150	46
Interest expense, net	(95)	(99)	(193)	(206)
Other income/(expense), net	20	(118)	85	(155)
Income before tax	392	298	920	544
Income tax expense	(43)	(47)	(96)	(68)
Net income	349	251	824	476
Net income attributable to noncontrolling interests	(56)	(48)	(109)	(86)
Net income attributable to PAA	$ 293	$ 203	$ 715	$ 390

(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 our 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, 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 settle in cash is not excluded in determining Segment Adjusted EBITDA. See Note 18 to our Consolidated Financial Statements included in Part IV of our 2022 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) Includes costs recognized during the period related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance. See Note 9 for additional information regarding the Line 901 incident.

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

Note 11— Acquisitions and Divestitures

Acquisitions

OMOG Acquisition. On July 28, 2023, we acquired the remaining 43% interest in OMOG JV LLC ("OMOG") for approximately $225 million ($145 million net to our 65% interest in the Permian JV). As a result of this transaction, we now own 100% of OMOG and its subsidiaries and such entities will be reflected as consolidated subsidiaries in our consolidated financial statements. Prior to this transaction, our 57% interest in OMOG was accounted for as an equity method investment.

Divestitures

Keyera Fort Saskatchewan Divestiture. In February 2023, we sold our 21% non-operated/undivided joint interest in the Keyera Fort Saskatchewan facility for approximately $270 million. As of December 31, 2022, we classified the assets related to this transaction (primarily "Property and equipment" in our NGL segment), valued at the lower of the carrying amount or fair value less costs to sell, of approximately $130 million as assets held for sale, which is reflected in "Other current assets" on our Condensed Consolidated Balance Sheet. Upon the sale of this facility, we recognized a gain of approximately $140 million which is included in "(Gains)/losses on asset sales and asset impairments, net" on our Condensed Consolidated Statement of Operations.

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 2022 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 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 six months of 2023, we recognized net income attributable to PAA of $715 million compared to $390 million during the first six months of 2022. The increase in operating results for the first six months of 2023 over the comparable 2022 period was driven primarily by more favorable results in our Crude Oil segment resulting from higher volumes on our pipelines and market-based opportunities. In addition, the 2022 comparative period was impacted by an increase in the accrual for estimated costs associated with the Line 901 incident.

Additionally, net income for the first six months of 2023 compared to the first six months of 2022 includes more favorable impacts from gains on asset sales and the mark-to-market adjustment of the Preferred Distribution Rate Reset Option, partially offset by less favorable impacts of long-term inventory costing adjustments.

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 June 30,		Variance		Six Months Ended June 30,		Variance	
	2023	2022	$	%	2023	2022	$	%
Product sales revenues	$ 11,201	$ 16,007	$ (4,806)	(30)%	$ 23,145	$ 29,388	$ (6,243)	(21)%
Services revenues	401	352	49	14 %	798	665	133	20 %
Purchases and related costs	(10,544)	(15,324)	4,780	31 %	(21,867)	(28,109)	6,242	22 %
Field operating costs	(333)	(307)	(26)	(8)%	(690)	(653)	(37)	(6)%
General and administrative expenses	(85)	(78)	(7)	(9)%	(171)	(160)	(11)	(7)%
Depreciation and amortization	(259)	(242)	(17)	(7)%	(515)	(473)	(42)	(9)%
Gains/(losses) on asset sales and asset impairments, net	(3)	3	(6)	(200)%	150	46	104	226 %
Equity earnings in unconsolidated entities	89	104	(15)	(14)%	178	201	(23)	(11)%
Interest expense, net	(95)	(99)	4	4 %	(193)	(206)	13	6 %
Other income/(expense), net	20	(118)	138	117 %	85	(155)	240	155 %
Income tax expense	(43)	(47)	4	9 %	(96)	(68)	(28)	(41)%
Net income	349	251	98	39 %	824	476	348	73 %
Net income attributable to noncontrolling interests	(56)	(48)	(8)	(17)%	(109)	(86)	(23)	(27)%
Net income attributable to PAA	$ 293	$ 203	$ 90	44 %	$ 715	$ 390	$ 325	83 %
Basic and diluted net income per common unit	$ 0.32	$ 0.22	$ 0.10	**	$ 0.84	$ 0.41	$ 0.43	**
Basic and diluted weighted average common units outstanding	698	702	(4)	**	698	703	(5)	**

** 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. 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 WTI. The following table presents the range of NYMEX WTI benchmark prices of crude oil (in dollars per barrel):

	NYMEX WTI Crude Oil Price		
	Low	**High**	**Average**
Three Months Ended June 30, 2023	$ 67	$ 83	$ 74
Three Months Ended June 30, 2022	$ 94	$ 122	$ 109
Six Months Ended June 30, 2023	$ 67	$ 83	$ 75
Six Months Ended June 30, 2022	$ 76	$ 124	$ 102

Product sales revenues and purchases decreased for the three and six months ended June 30, 2023 compared to the same periods in 2022 primarily due to lower commodity prices in the 2023 periods. The decrease for the six-month period was partially offset by higher volumes in the 2023 period.

Revenues from services increased for the three and six months ended June 30, 2023 compared to the same periods in 2022 primarily due to higher volumes and tariff escalations in the 2023 periods, as well as the impact of the consolidation of Cactus II resulting from our acquisition of an additional interest in November 2022.

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 and six months ended June 30, 2023 compared to the same periods in 2022 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 on equity-classified awards (which is excluded in the calculation of Adjusted EBITDA and Segment Adjusted EBITDA), partially offset by (iii) lower transition costs associated with the formation of the Permian JV and (iv) the impact of exchange rate fluctuations.

Gains/(Losses) on Asset Sales and Asset Impairments, Net

The net gains on asset sales and asset impairments for the six months ended June 30, 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 11 to our Condensed Consolidated Financial Statements for additional discussion of this transaction.

During the first quarter of 2022, we recognized a gain of $40 million related to the sale of land and buildings in California.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and six months ended June 30, 2023 compared to the same periods in 2022 was largely driven by our acquisition of an additional interest in Cactus II, for which our ownership interest is now consolidated. See Note 7 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for additional information.

Interest Expense, Net

The decrease in interest expense for the three and six months ended June 30, 2023 compared to the three and six months ended June 30, 2022 was primarily due to a lower weighted average debt balance during the 2023 periods largely driven by the repayment of $750 million of senior notes in March 2022 and $400 million of senior notes in January 2023.

Other Income/(Expense), Net

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Gain/(loss) on mark-to-market adjustment of Preferred Distribution Rate Reset Option embedded derivative [1]	$ —	$ (103)	$ 58	$ (147)
Net gain/(loss) on foreign currency revaluation [2]	14	(16)	14	(9)
Other	6	1	13	1
	$ 20	$ (118)	$ 85	$ (155)

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

(2) 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.

Income Tax (Expense)/Benefit

The net unfavorable income tax variance for the six months ended June 30, 2023 compared to the same period in 2022 was primarily a result of increased activity within our Canadian operations including the tax impact of the Keyera Fort Saskatchewan divestiture in the first quarter of 2023.

Noncontrolling Interests

The increase in amounts attributable to noncontrolling interests for the three and six months ended June 30, 2023 compared to the same periods in 2022 was primarily due to (i) the consolidation of Cactus II in November 2022 and (ii) higher results from the Permian JV in the 2023 periods. See Note 7 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for additional information on the Cactus II transaction.

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"), Free Cash Flow and Free Cash Flow after Distributions.

Adjusted EBITDA is defined as earnings before interest, 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 asset impairments and gains on and impairments of investments in unconsolidated entities, adjusted for certain selected items impacting comparability.

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 Free Cash Flow and 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 Free Cash Flow and Free Cash Flow after Distributions.

Non-GAAP Financial Performance Measures

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 June 30, 2023	Three Months Ended June 30, 2022	Variance $	Variance %	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022	Variance $	Variance %
Net income	$ 349	$ 251	$ 98	39 %	$ 824	$ 476	$ 348	73 %
Interest expense, net	95	99	(4)	(4)%	193	206	(13)	(6)%
Income tax expense	43	47	(4)	(9)%	96	68	28	41 %
Depreciation and amortization	259	242	17	7 %	515	473	42	9 %
(Gains)/losses on asset sales and asset impairments, net	3	(3)	6	200 %	(150)	(46)	(104)	(226)%
Depreciation and amortization of unconsolidated entities [(1)]	24	17	7	41 %	47	37	10	27 %
Selected Items Impacting Comparability:								
Derivative activities and inventory valuation adjustments	(86)	(75)	(11)	**	6	13	(7)	**
Long-term inventory costing adjustments	2	(13)	15	**	31	(105)	136	**
Deficiencies under minimum volume commitments, net	(2)	10	(12)	**	(9)	15	(24)	**
Equity-indexed compensation expense	8	7	1	**	17	15	2	**
Foreign currency revaluation	19	3	16	**	15	1	14	**
Line 901 incident	—	—	—	**	—	85	(85)	**
Selected Items Impacting Comparability - Segment Adjusted EBITDA [(2)]	(59)	(68)	9	**	60	24	36	**
Mark-to-market adjustment of Preferred Distribution Rate Reset Option embedded derivative [(3)]	—	103	(103)	**	(58)	147	(205)	**
Foreign currency revaluation [(4)]	(14)	16	(30)	**	(14)	9	(23)	**
Selected Items Impacting Comparability - Adjusted EBITDA [(5)]	(73)	51	(124)	**	(12)	180	(192)	**
Adjusted EBITDA [(5)]	$ 700	$ 704	$ (4)	(1)%	$ 1,513	$ 1,394	$ 119	9 %
Adjusted EBITDA attributable to noncontrolling interests [(6)]	(103)	(89)	(14)	(16)%	(201)	(166)	(35)	(21)%
Adjusted EBITDA attributable to PAA	$ 597	$ 615	$ (18)	(3)%	$ 1,312	$ 1,228	$ 84	7 %

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Variance $	Variance %	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022	Variance $	Variance %
Adjusted EBITDA [5]	$ 700	$ 704	$ (4)	(1)%	$ 1,513	$ 1,394	$ 119	9 %
Interest expense, net of certain non-cash items [7]	(90)	(97)	7	7 %	(183)	(199)	16	8 %
Maintenance capital [8]	(62)	(43)	(19)	(44)%	(109)	(70)	(39)	(56)%
Investment capital of noncontrolling interests [9]	(17)	(15)	(2)	(13)%	(40)	(30)	(10)	(33)%
Current income tax expense	(20)	(30)	10	33 %	(81)	(48)	(33)	(69)%
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings [10]	(8)	5	(13)	**	(20)	(26)	6	**
Distributions to noncontrolling interests [11]	(73)	(62)	(11)	(18)%	(151)	(121)	(30)	(25)%
Implied DCF	$ 430	$ 462	$ (32)	(7)%	$ 929	$ 900	$ 29	3 %
Preferred unit distributions [11]	(59)	(62)	3	5 %	(115)	(99)	(16)	(16)%
Implied DCF Available to Common Unitholders	$ 371	$ 400	$ (29)	(7)%	$ 814	$ 801	$ 13	2 %
Common unit cash distributions [11]	(187)	(153)			(374)	(280)		
Implied DCF Excess [12]	$ 184	$ 247			$ 440	$ 521		

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

(8) 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.

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

(10) 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).

(11) Cash distributions paid during the period presented.

(12) 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 20 to our Consolidated Financial Statements included in Part IV of our 2022 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 prices 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 primarily impacted by (i) increases or decreases in our lease gathering crude oil purchases volumes and (ii) volatility in commodity prices, as well as grade and regional price differentials and 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] (in millions)	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Variance $	Variance %	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022	Variance $	Variance %
Revenues	$ 11,295	$ 15,940	$ (4,645)	(29)%	$ 23,053	$ 29,019	$ (5,966)	(21)%
Purchases and related costs	(10,490)	(15,163)	4,673	31 %	(21,430)	(27,556)	6,126	22 %
Field operating costs	(256)	(233)	(23)	(10)%	(513)	(515)	2	— %
Segment general and administrative expenses [2]	(66)	(59)	(7)	(12)%	(133)	(122)	(11)	(9)%
Equity earnings in unconsolidated entities	89	104	(15)	(14)%	178	201	(23)	(11)%
Adjustments [3]:								
Depreciation and amortization of unconsolidated entities	24	17	7	**	47	37	10	**
Derivative activities and inventory valuation adjustments	5	(29)	34	**	(7)	30	(37)	**
Long-term inventory costing adjustments	10	(13)	23	**	31	(98)	129	**
Deficiencies under minimum volume commitments, net	(2)	10	(12)	**	(9)	15	(24)	**
Equity-indexed compensation expense	8	7	1	**	17	15	2	**
Foreign currency revaluation	15	2	13	**	12	1	11	**
Line 901 incident	—	—	—	**	—	85	(85)	**
Adjusted EBITDA attributable to noncontrolling interests	(103)	(89)	(14)	**	(200)	(166)	(34)	**
Segment Adjusted EBITDA	$ 529	$ 494	$ 35	7 %	$ 1,046	$ 946	$ 100	11 %
Maintenance capital expenditures	$ 36	$ 25	$ 11	44 %	$ 67	$ 45	$ 22	49 %

Average Volumes	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Variance Volumes	Variance %	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022	Variance Volumes	Variance %
Crude oil pipeline tariff (by region) [4]								
Permian Basin [5]	6,304	5,434	870	16 %	6,299	5,324	975	18 %
Other [5]	2,088	1,983	105	5 %	2,037	1,965	72	4 %
Total crude oil pipeline tariff	8,392	7,417	975	13 %	8,336	7,289	1,047	14 %
Commercial crude oil storage capacity [5][6]	72	72	—	— %	72	72	—	— %
Crude oil lease gathering purchases [4]	1,408	1,368	40	3 %	1,418	1,364	54	4 %

** 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 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 assets acquired during the periods 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 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 and six months ended June 30, 2023 compared to the same periods in 2022 primarily due to higher volumes on our pipeline systems, particularly on our Permian Basin and Capline assets, tariff escalations and favorable Canadian market-based opportunities. These items were partially offset by the impact of increased operating expenses, minimum volume commitment deficiency payments received in the first half of 2022 and lower commodity prices.

The following is a more detailed discussion of the significant factors impacting Segment Adjusted EBITDA for the three and six months ended June 30, 2023 compared to the same periods in 2022.

- *Pipeline Revenue.* Our Permian Basin pipelines were favorably impacted by higher gathering volumes, which were underpinned by increased production and new well connections, the acquisition of an additional interest in Cactus II in November of 2022 and tariff escalations. Increased volumes on the Capline system also contributed to increased earnings in the 2023 periods. These benefits were partially offset by the impact of minimum volume commitment deficiency payments received in the first half of 2022, as well as lower commodity prices in the 2023 periods impacting pipeline loss allowance revenues.

  A majority of our Permian Basin gathering and intra-basin pipelines are owned by the Permian JV, a consolidated entity in which we own a 65% interest, and our Permian Basin long-haul pipelines include Cactus II, in which we own a 70% interest. We deduct the portion of the financial results attributable to noncontrolling interests in the Permian JV and Cactus II in determining Segment Adjusted EBITDA.

- *Market Opportunities.* Our results for the three and six months ended June 30, 2023 include the impact of favorable Canadian crude oil market-based opportunities. This was partially offset by the favorable impact to the 2022 periods of the sale of excess linefill in a higher crude oil price environment.

- *Field Operating Costs.* Field operating costs were lower for the six months ended June 30, 2023 compared to the same period in 2022 due to the recognition of additional estimated costs associated with the Line 901 incident in the first quarter of 2022 (which impact field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above). For the three and six months ended June 30, 2023 compared to the same periods in 2022, we had higher expenses associated with (i) utilities costs due to a combination of higher volumes and prices and an increase in the amount of drag reducing agents used, (ii) incremental consolidated operating costs in connection with our acquisition of an additional interest in Cactus II, (iii) employee-related costs primarily resulting from higher average headcount and salaries, (iv) chemical treatment costs and (v) unrealized mark-to-market losses on power hedges for the six-month period (which impact our field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above).

Maintenance Capital. The increase in maintenance capital spending for the three and six months ended June 30, 2023 compared to the same periods in 2022 was primarily due to timing of routine integrity and tank 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 prices, the differential between the price of natural gas and the extracted NGL ("frac spread"), as well as location differentials and time spreads, and (iii) the volume of natural gas transported on third-party assets through our Empress 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 June 30, 2023	Three Months Ended June 30, 2022	Variance $	Variance %	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022	Variance $	Variance %
Revenues	$ 381	$ 570	$ (189)	(33)%	$ 1,071	$ 1,304	$ (233)	(18)%
Purchases and related costs	(128)	(312)	184	59 %	(618)	(823)	205	25 %
Field operating costs	(77)	(74)	(3)	(4)%	(177)	(138)	(39)	(28)%
Segment general and administrative expenses [2]	(19)	(19)	—	— %	(38)	(38)	—	— %
Adjustments [3]:								
Derivative activities	(91)	(46)	(45)	**	13	(17)	30	**
Long-term inventory costing adjustments	(8)	—	(8)	**	—	(7)	7	**
Foreign currency revaluation	4	1	3	**	3	—	3	**
Segment Adjusted EBITDA	$ 62	$ 120	$ (58)	(48)%	$ 254	$ 281	$ (27)	(10)%
Maintenance capital expenditures	$ 26	$ 18	$ 8	44 %	$ 42	$ 25	$ 17	68 %

Average Volumes (in thousands of barrels per day) [4]	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Variance Volumes	Variance %	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022	Variance Volumes	Variance %
NGL fractionation	83	137	(54)	(39)%	113	136	(23)	(17)%
NGL pipeline tariff	147	187	(40)	(21)%	170	182	(12)	(7)%
Propane and butane sales [5]	39	58	(19)	(33)%	89	96	(7)	(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.

(5) During the fourth quarter of 2022, we modified our sales volumes reported to include only propane and butane sales. Prior to the fourth quarter of 2022, our reported sales volumes included other NGL products, primarily ethane, that represented a significant portion of our total NGL sales volumes but did not contribute significantly to Segment Adjusted EBITDA. Sales volumes for earlier periods presented herein have been recast to include only propane and butane.

Segment Adjusted EBITDA

NGL Segment Adjusted EBITDA decreased for the three months ended June 30, 2023 compared to the same period in 2022 primarily due to lower propane sales volumes, impacted by turnarounds and deferring sales due to market structure, and the absence of weather events that benefited the 2022 period.

These unfavorable impacts were partially offset for the six months ended June 30, 2023 compared to the same period in 2022 by the favorable impact during the first quarter of 2023 of higher butane sales volumes combined with favorable NGL basis differentials.

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 June 30, 2023 compared to the same period in 2022 primarily due to (i) lower propane sales volumes impacted by turnarounds at our facilities and by third-party asset turnarounds and outages, (ii) the impact of deferring sales for the 2023 period to winter months due to market structure, (iii) the absence of weather events that benefited the 2022 period, (iv) higher gains at certain of our NGL facilities in 2022 and (v) the sale of our ownership interest in the Keyera Fort Saskatchewan facility in the first quarter of 2023, partially offset by (vi) higher processing revenues at our Empress straddle plants resulting from a commercial agreement executed in conjunction with the increase in our Empress ownership in the fourth quarter of 2022.

These unfavorable impacts were partially offset for the six months ended June 30, 2023 compared to the same period in 2022 by the favorable impact during the first quarter of 2023 of higher butane sales volumes resulting from higher production and increased third-party demand, combined with favorable NGL basis differentials.

Field Operating Costs. The increase in field operating costs for the six months ended June 30, 2023 compared to the same periods in 2022 was primarily due to increased utilities-related costs largely as a result of higher prices, as well as our increased ownership in the Empress straddle plants effective in the fourth quarter of 2022. The increase in utilities-related costs was partially offset by the benefit to net revenues of operating cost recoveries realized through commercial agreements, as well as the impact of exchange rate fluctuations.

Maintenance Capital. The increase in maintenance capital spending for the three and six months ended June 30, 2023 compared to the same periods in 2022 was primarily due to timing of routine integrity maintenance and periodic scheduled outages.

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 June 30, 2023, we had approximately $3.5 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 June 30, 2023
Availability under senior unsecured revolving credit facility (1) (2)	$ 1,272
Availability under senior secured hedged inventory facility (1) (2)	1,301
Amounts outstanding under commercial paper program	—
Subtotal	2,573
Cash and cash equivalents (3)	915
Total	$ 3,488

(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 of $78 million and $49 million, respectively.

(3) Excludes restricted cash of $18 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 June 30, 2023.

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 2022 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 Free Cash Flow and 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. 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 and proceeds from the sale of noncontrolling interests. Free Cash Flow is further reduced by cash distributions paid to our preferred and common unitholders to arrive at 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 Free Cash Flow and Free Cash Flow after Distributions to Net Cash Provided by Operating Activities (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Net cash provided by operating activities	$ 888	$ 792	$ 1,631	$ 1,132
Adjustments to reconcile Net cash provided by operating activities to Free Cash Flow:				
Net cash used in investing activities	(165)	(42)	(6)	(123)
Cash distributions paid to noncontrolling interests [(1)]	(73)	(62)	(151)	(121)
Free Cash Flow	$ 650	$ 688	$ 1,474	$ 888
Cash distributions [(2)]	(246)	(215)	(489)	(379)
Free Cash Flow after Distributions	$ 404	$ 473	$ 985	$ 509

(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 2022 Annual Report on Form 10-K.

Net cash provided by operating activities for the first six months of 2023 and 2022 was $1.631 billion and $1.132 billion, respectively, and primarily resulted from earnings from our operations. In addition, the 2023 period was favorably impacted by net positive changes in working capital items, 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 and maintenance capital expenditures (in millions):

	Six Months Ended June 30,	
	2023	2022
Investment capital [(1) (2) (3)]	$ 182	$ 181
Maintenance capital [(1) (3)]	109	70
	$ 291	$ 251

(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) Includes contributions to unconsolidated entities, accounted for under the equity method of accounting, related to investment capital projects by such entities.

(3) Investment capital and maintenance capital, net to our interest, was approximately $141 million and $103 million, respectively, for the six months ended June 30, 2023, and approximately $151 million and $67 million, respectively, for the six months ended June 30, 2022.

2023 Investment and Maintenance Capital. Total investment capital for the year ending December 31, 2023 is projected to be approximately $420 million ($325 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 2023 is projected to be $205 million ($195 million net to our interest). We expect to fund our 2023 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 six months of 2023 and 2022 from sales of assets (in millions):

	Six Months Ended June 30,	
	2023	2022
Proceeds from divestitures [(1)]	$ 284	$ 57

(1) Represents proceeds, including working capital adjustments, net of transaction costs. The proceeds from divestitures for the six months ended June 30, 2023 are primarily from the sale of our 21% non-operated/undivided joint interest in the Keyera Fort Saskatchewan facility in February 2023. See Note 11 to our Condensed Consolidated Financial Statements 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 sale of non-core assets, the sale of partial interests in assets to strategic joint venture partners, acquisitions and large investment capital projects. With respect to a potential divestiture or acquisition, 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 buyers (in the case of a divestiture) or sellers (in the case of an acquisition). 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 2022 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

We had no net borrowings or repayments under our credit facilities or commercial paper program during the six months ended June 30, 2023.

During the six months ended June 30, 2022, we had net borrowings under our credit facilities and commercial paper program of approximately $115 million. The net borrowings resulted primarily from borrowings during the period related to funding needs for capital investments, inventory purchases, senior notes repayments and other general partnership purposes, partially offset by cash flow from operating activities and proceeds from asset sales.

Repayment of Senior Notes

On January 31, 2023, we redeemed our 2.85%, $400 million senior notes. We utilized a combination of cash on hand and borrowings under our commercial paper program to repay these senior notes. We also intend to utilize a combination of cash flow from operating activities, proceeds from asset sales and borrowings under our commercial paper program to repay our 3.85%, $700 million senior notes due October 2023.

Common Equity Repurchase Program

We repurchased 7.3 million common units under the Common Equity Repurchase Program (the “Program”) during the six months ended June 30, 2022 for a total purchase price of $74 million, including commissions and fees. There were no repurchases under the Program during the six months ended June 30, 2023. The remaining available capacity under the Program as of June 30, 2023 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 June 30, 2023. 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 six months ended June 30, 2023.

Distributions to Our Unitholders

Series A preferred unitholders. On August 14, 2023, 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 July 31, 2023 for the period from April 1, 2023 through June 30, 2023.

Series B preferred unitholders. On August 15, 2023, we will pay a quarterly cash distribution of approximately $24.10 per unit to Series B preferred unitholders of record at the close of business on August 1, 2023 for the period from May 15, 2023 through August 14, 2023.

Common Unitholders. On August 14, 2023, we will pay a quarterly cash distribution of $0.2675 per common unit ($1.07 per unit on an annualized basis) to common unitholders of record at the close of business on July 31, 2023 for the period from April 1, 2023 through June 30, 2023, which is unchanged from the distribution per unit paid in May of 2023.

See Note 6 to our Condensed Consolidated Financial Statements for details of distributions paid during or pertaining to the first six months of 2023, 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 June 30, 2023, 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 six months ended June 30, 2023.

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 June 30, 2023 (in millions):

	Remainder of 2023	2024	2025	2026	2027	2028 and Thereafter	Total
Crude oil, NGL and other purchases [1]	$ 10,541	$ 17,947	$ 16,685	$ 15,565	$ 13,612	$ 37,916	$ 112,266

(1) Amounts are primarily based on estimated volumes and market prices based on average activity during June 2023. 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 70 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 June 30, 2023 and December 31, 2022, we had outstanding letters of credit of approximately $127 million and $102 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 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 crude oil prices (whether due to pandemics or other factors) 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 in areas supplied by our mainlines 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 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, governmental regulations, executive orders, trade policies, accounting standards and statements, and related interpretations, including legislation, executive orders or regulatory initiatives that prohibit, restrict or regulate hydraulic fracturing or that prohibit the development of oil and gas resources and the related infrastructure on lands dedicated to or served by our pipelines, or that negatively impact our ability to develop, operate or repair midstream assets;
- 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, divestitures, joint ventures, acquisitions 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 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; 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 2022 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 June 30, 2023 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	$ 25	$ (14)	$ 15
Natural gas	(35)	$ 7	$ (7)
NGL and other	173	$ (18)	$ 18
Total fair value	$ 163		

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

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. We did not have any variable rate debt outstanding at June 30, 2023. The average interest rate on variable rate debt that was outstanding during the six months ended June 30, 2023 was 5.1%, based upon rates in effect during such period. The fair value of our interest rate derivatives was a net asset of $42 million as of June 30, 2023. A 10% increase in the forward SOFR curve as of June 30, 2023 would have resulted in an increase of $16 million to the fair value of our interest rate derivatives. A 10% decrease in the forward SOFR curve as of June 30, 2023 would have resulted in a decrease of $16 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.

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 June 30, 2023, 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 second quarter of 2023 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 2022 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 June 30, 2023, 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	—	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).
3.15	—	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).

3.16	—	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).
3.17	—	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).
3.18	—	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).
3.19	—	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).
3.20	—	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).
3.21	—	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-Fourth Supplemental Indenture (3.85% Senior Notes due 2023) dated August 15, 2013, 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 15, 2013).
4.7	—	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).
4.8	—	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).
4.9	—	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).

4.1	—	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).
4.11	—	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).
4.12	—	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).
4.13	—	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).
4.14	—	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).
4.15	—	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).
4.16	—	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).
4.17	—	Description of Our Securities (incorporated by reference to Exhibit 4.18 to our Annual Report on Form 10-K for the year ended December 31, 2022).
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.

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)

August 8, 2023

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

August 8, 2023

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

August 8, 2023

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: August 8, 2023

/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: August 8, 2023

/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 June 30, 2023 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: August 8, 2023

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 June 30, 2023 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: August 8, 2023