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, 2019

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	New York Stock Exchange

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

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

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

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, 2019, there were 727,424,619 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, 2019	December 31, 2018
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 419	$ 66
Restricted cash	42	—
Trade accounts receivable and other receivables, net	2,835	2,454
Inventory	558	640
Other current assets	428	373
Total current assets	4,282	3,533
PROPERTY AND EQUIPMENT	18,460	17,866
Accumulated depreciation	(3,319)	(3,079)
Property and equipment, net	15,141	14,787
OTHER ASSETS		
Goodwill	2,537	2,521
Investments in unconsolidated entities	3,377	2,702
Linefill and base gas	922	916
Long-term operating lease right-of-use assets, net	469	—
Long-term inventory	152	136
Other long-term assets, net	877	916
Total assets	$ 27,757	$ 25,511
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Trade accounts payable	$ 3,042	$ 2,704
Short-term debt	470	66
Other current liabilities	782	686
Total current liabilities	4,294	3,456
LONG-TERM LIABILITIES		
Senior notes, net	8,945	8,941
Other long-term debt, net	231	202
Long-term operating lease liabilities	370	—
Other long-term liabilities and deferred credits	844	910
Total long-term liabilities	10,390	10,053
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
PARTNERS' CAPITAL		
Series A preferred unitholders (71,090,468 and 71,090,468 units outstanding, respectively)	1,505	1,505
Series B preferred unitholders (800,000 and 800,000 units outstanding, respectively)	787	787
Common unitholders (727,424,619 and 726,361,924 units outstanding, respectively)	10,649	9,710
Total partners' capital excluding noncontrolling interests	12,941	12,002
Noncontrolling interests	132	—
Total partners' capital	13,073	12,002
Total liabilities and partners' capital	$ 27,757	$ 25,511

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,	
	2019	2018	2019	2018
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$ 7,914	$ 7,781	$ 15,936	$ 15,892
Transportation segment revenues	188	152	385	298
Facilities segment revenues	151	147	307	288
Total revenues	8,253	8,080	16,628	16,478
COSTS AND EXPENSES				
Purchases and related costs	7,244	7,551	14,362	15,070
Field operating costs	340	312	667	605
General and administrative expenses	75	80	151	159
Depreciation and amortization	147	130	283	256
(Gains)/losses on asset sales and asset impairments, net	(4)	(81)	—	(81)
Total costs and expenses	7,802	7,992	15,463	16,009
OPERATING INCOME	451	88	1,165	469
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	83	96	172	171
Gain on investment in unconsolidated entities (Note 7)	—	—	267	—
Interest expense (net of capitalized interest of $11, $7, $22 and $13, respectively)	(103)	(111)	(203)	(217)
Other income/(expense), net	(6)	11	18	10
INCOME BEFORE TAX	425	84	1,419	433
Current income tax expense	(24)	(7)	(53)	(20)
Deferred income tax (expense)/benefit	47	23	52	(25)
NET INCOME	448	100	1,418	388
Net income attributable to noncontrolling interests	(2)	—	(2)	—
NET INCOME ATTRIBUTABLE TO PAA	$ 446	$ 100	$ 1,416	$ 388
NET INCOME PER COMMON UNIT (NOTE 4):				
Net income allocated to common unitholders — Basic	$ 395	$ 50	$ 1,311	$ 286
Basic weighted average common units outstanding	727	725	727	725
Basic net income per common unit	$ 0.54	$ 0.07	$ 1.80	$ 0.39
Net income allocated to common unitholders — Diluted	$ 433	$ 50	$ 1,389	$ 286
Diluted weighted average common units outstanding	800	727	800	727
Diluted net income per common unit	$ 0.54	$ 0.07	$ 1.74	$ 0.39

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 COMPREHENSIVE INCOME
(in millions)

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
	(unaudited)		(unaudited)	
Net income	$ 448	$ 100	$ 1,418	$ 388
Other comprehensive income/(loss)	51	(56)	109	(121)
Comprehensive income	499	44	1,527	267
Comprehensive income attributable to noncontrolling interests	(2)	—	(2)	—
Comprehensive income attributable to PAA	$ 497	$ 44	$ 1,525	$ 267

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, 2018	$ (177)	$ (853)	$ —	$ (1,030)
Reclassification adjustments	5	—	—	5
Unrealized loss on hedges	(58)	—	—	(58)
Currency translation adjustments	—	161	—	161
Other	—	—	1	1
Total period activity	(53)	161	1	109
Balance at June 30, 2019	$ (230)	$ (692)	$ 1	$ (921)

	Derivative Instruments	Translation Adjustments	Other	Total
		(unaudited)		
Balance at December 31, 2017	$ (223)	$ (548)	$ 1	$ (770)
Reclassification adjustments	5	—	—	5
Unrealized gain on hedges	45	—	—	45
Currency translation adjustments	—	(171)	—	(171)
Total period activity	50	(171)	—	(121)
Balance at June 30, 2018	$ (173)	$ (719)	$ 1	$ (891)

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 CASH FLOWS
(in millions)

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 1,418	$ 388
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	283	256
(Gains)/losses on asset sales and asset impairments, net	—	(81)
Equity-indexed compensation expense	24	36
Deferred income tax expense/(benefit)	(52)	25
Settlement of terminated interest rate hedging instruments	(22)	14
Equity earnings in unconsolidated entities	(172)	(171)
Distributions on earnings from unconsolidated entities	200	206
Gain on investment in unconsolidated entities (Note 7)	(267)	—
Other	8	13
Changes in assets and liabilities, net of acquisitions	44	329
Net cash provided by operating activities	1,464	1,015
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(47)	—
Investments in unconsolidated entities	(259)	(216)
Additions to property, equipment and other	(642)	(724)
Proceeds from sales of assets	2	426
Cash paid for purchases of linefill and base gas	(24)	—
Other investing activities	(8)	8
Net cash used in investing activities	(978)	(506)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings under commercial paper program (Note 8)	218	135
Net borrowings under senior unsecured revolving credit facility (Note 8)	—	126
Net borrowings/(repayments) under senior secured hedged inventory facility (Note 8)	100	(333)
Distributions paid to Series A preferred unitholders (Note 9)	(74)	(37)
Distributions paid to Series B preferred unitholders (Note 9)	(25)	(25)
Distributions paid to common unitholders (Note 9)	(480)	(435)
Sale of noncontrolling interest in a subsidiary (Note 9)	128	—
Other financing activities	45	60
Net cash used in financing activities	(88)	(509)
Effect of translation adjustment	(3)	(3)
Net increase/(decrease) in cash and cash equivalents and restricted cash	395	(3)
Cash and cash equivalents and restricted cash, beginning of period	66	37
Cash and cash equivalents and restricted cash, end of period	$ 461	$ 34
Cash paid for:		
Interest, net of amounts capitalized	$ 188	$ 203
Income taxes, net of amounts refunded	$ 86	$ 11

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
(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, 2018	$ 1,505	$ 787	$ 9,710	$ 12,002	$ —	$ 12,002
Net income	74	25	1,317	1,416	2	1,418
Distributions (Note 9)	(74)	(25)	(480)	(579)	—	(579)
Other comprehensive income	—	—	109	109	—	109
Equity-indexed compensation expense	—	—	7	7	—	7
Sale of noncontrolling interest in a subsidiary (Note 9)	—	—	(2)	(2)	130	128
Other	—	—	(12)	(12)	—	(12)
Balance at June 30, 2019	$ 1,505	$ 787	$ 10,649	$ 12,941	$ 132	$ 13,073

	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, 2019	$ 1,505	$ 787	$ 10,470	$ 12,762	$ —	$ 12,762
Net income	37	12	397	446	2	448
Distributions (Note 9)	(37)	(12)	(262)	(311)	—	(311)
Other comprehensive income	—	—	51	51	—	51
Equity-indexed compensation expense	—	—	4	4	—	4
Sale of noncontrolling interest in a subsidiary (Note 9)	—	—	(2)	(2)	130	128
Other	—	—	(9)	(9)	—	(9)
Balance at June 30, 2019	$ 1,505	$ 787	$ 10,649	$ 12,941	$ 132	$ 13,073

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
(continued)
(in millions)

	Limited Partners			
	Preferred Unitholders			
	Series A	Series B	Common Unitholders	Total Partners' Capital
	(unaudited)			
Balance at December 31, 2017	$ 1,505	$ 788	$ 8,665	$ 10,958
Impact of adoption of ASU 2017-05	—	—	113	113
Balance at January 1, 2018	1,505	788	8,778	11,071
Net income	74	25	289	388
Distributions	(74)	(25)	(435)	(534)
Other comprehensive loss	—	—	(121)	(121)
Equity-indexed compensation expense	—	—	23	23
Other	—	(1)	(2)	(3)
Balance at June 30, 2018	$ 1,505	$ 787	$ 8,532	$ 10,824

	Limited Partners			
	Preferred Unitholders			
	Series A	Series B	Common Unitholders	Total Partners' Capital
	(unaudited)			
Balance at March 31, 2018	$ 1,505	$ 787	$ 8,744	$ 11,036
Net income	37	12	51	100
Distributions	(37)	(12)	(218)	(267)
Other comprehensive loss	—	—	(56)	(56)
Equity-indexed compensation expense	—	—	12	12
Other	—	—	(1)	(1)
Balance at June 30, 2018	$ 1,505	$ 787	$ 8,532	$ 10,824

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.

We own and operate midstream energy infrastructure and provide logistics services primarily for crude oil, natural gas liquids (“NGL”) and natural gas. 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 business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics. See Note 14 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, 2019, AAP also owned a limited partner interest in us through its ownership of approximately 268.5 million of our common units (approximately 34% 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, 2019, owned an approximate 63% 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
DERs	=	Distribution equivalent rights
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
LIBOR	=	London Interbank Offered Rate
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
NGL	=	Natural gas liquids, including ethane, propane and butane
NYMEX	=	New York Mercantile Exchange
Oxy	=	Occidental Petroleum Corporation or its subsidiaries
PLA	=	Pipeline loss allowance
SEC	=	United States Securities and Exchange Commission
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 2018 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. 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 transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation.

Effective for the fourth quarter of 2018, we present "(Gains)/losses on asset sales and asset impairments, net" as a separate line item on our Condensed Consolidated Statements of Operations. To conform to the current year presentation, amounts related to gains and losses on asset sales and asset impairments previously presented in "Depreciation and amortization" are now presented in "(Gains)/losses on asset sales and asset impairments, net" on our Condensed Consolidated Statements of Operations. This change was applied retrospectively and does not affect Operating income, Net income or Net income attributable to PAA.

The condensed consolidated balance sheet data as of December 31, 2018 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, 2019 should not be taken as indicative of results to be expected for the entire year.

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

Note 2—Summary of Significant Accounting Policies

Restricted Cash

Restricted cash includes cash held by us that is unavailable for general use and is comprised of amounts advanced to us by certain equity method investees related to the construction of fixed assets where we serve as construction manager. The following table presents a reconciliation of cash and cash equivalents and restricted cash reported on our Condensed Consolidated Balance Sheet that sum to the total of the amounts shown on our Condensed Consolidated Statement of Cash Flows as of the end of the period (in millions):

	June 30, 2019
Cash and cash equivalents	$ 419
Restricted cash	42
Total cash and cash equivalents and restricted cash	$ 461

We did not have any restricted cash as of December 31, 2018.

Recent Accounting Pronouncements

Except as discussed below and in our 2018 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, 2019 that are of significance or potential significance to us.

Accounting Standards Updates Adopted During the Period

In February 2016, the FASB issued ASU 2016-02, *Leases*, (followed by a series of related accounting standard updates (collectively referred to as “Topic 842”)), that revises the historical accounting model for leases. The most significant changes are the clarification of the definition of a lease and required lessee recognition on the balance sheet of right-of-use assets and lease liabilities with lease terms of more than 12 months (with the election of the practical expedient to exclude short-term leases on the balance sheet), including extensive quantitative and qualitative disclosures. This guidance became effective for interim and annual periods beginning after December 15, 2018. We adopted this guidance effective January 1, 2019. Our adoption resulted in the recording of additional net lease right-of-use assets and lease liabilities of approximately $560 million and $570 million, respectively, on January 1, 2019 and did not have a material impact on our results of operations or cash flows.

We elected the package of practical expedients permitted under the transition guidance within Topic 842, which, among other things, allowed us to carry forward the historical accounting related to lease identification, classification and indirect costs. We also elected the practical expedient related to land easements, allowing us to carry forward our accounting treatment for land easements (including rights of way) on existing agreements. Additionally, we elected the non-lease component separation practical expedient for certain classes of assets where we are the lessee and for all classes of assets where we are the lessor. Further, we elected the practical expedient which provides us with an optional transitional method, thereby applying the new guidance at the effective date, without adjusting the comparative periods and, if necessary, recognizing a cumulative-effect adjustment to the opening balance of Partners’ Capital upon adoption. There was no impact to retained earnings related to our adoption. We did not elect the practical expedient related to using hindsight in determining the lease term as this was not relevant following our election of the optional transitional method. We implemented a process to evaluate the impact of adopting this guidance on each type of lease contract we have entered into with counterparties. Our implementation team determined appropriate changes to our business processes, systems and controls to support recognition and disclosure under Topic 842. In addition to the above, which primarily relates to our accounting as a lessee, our accounting from a lessor perspective remains substantially unchanged under Topic 842. See Note 11 for information about our leases.

We also adopted the ASUs listed below effective January 1, 2019 and our adoption did not have a material impact to our financial position, results of operations or cash flows (see Note 2 to our Consolidated Financial Statements included in Part IV of our 2018 Annual Report on Form 10-K for additional information regarding these ASUs):

- ASU 2018-16, Derivatives and Hedging (Topic 815): Inclusion of the Secured Overnight Financing Rate (SOFR) Overnight Index Swap (OIS) Rate as a Benchmark Interest Rate for Hedge Accounting Purposes;
- ASU 2018-09, Codification Improvements;
- ASU 2018-07, Compensation—Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting; and
- ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities.

Accounting Standards Updates Issued During the Period

In May 2019, the FASB issued 2019-05, *Financial Instruments—Credit Losses (Topic 326): Targeted Transition Relief*, which provides transition relief and allows entities to elect the fair value option on certain financial instruments. We expect to adopt this guidance on January 1, 2020, and we are currently evaluating the effect that our adoption will have on our financial position, results of operations and cash flows.

In April 2019, the FASB issued 2019-04, *Codification Improvements to Topic 326, Financial Instruments—Credit Losses, Topic 815, Derivatives and Hedging, and Topic 825, Financial Instruments*, which clarifies certain aspects of accounting for credit losses, hedging activities and financial instruments. We expect to adopt this guidance on January 1, 2020, and we are currently evaluating the effect that our adoption will have on our financial position, results of operations and cash flows.

Note 3—Revenues and Accounts Receivable

Revenue Recognition

We disaggregate our revenues by segment and type of activity under ASC Topic 606, *Revenues from Contracts with Customers* (“Topic 606”). These categories depict how the nature, amount, timing and uncertainty of revenues and cash flows are affected by economic factors. See Note 3 to our Consolidated Financial Statements included in Part IV of our 2018 Annual Report on Form 10-K for additional information regarding our types of revenues and policies for revenue recognition.

The following tables present our Supply and Logistics segment, Transportation segment and Facilities segment revenues from contracts with customers disaggregated by type of activity (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Supply and Logistics segment revenues from contracts with customers				
Crude oil transactions	$ 7,595	$ 7,649	$ 14,532	$ 14,672
NGL and other transactions	269	475	1,178	1,626
Total Supply and Logistics segment revenues from contracts with customers	$ 7,864	$ 8,124	$ 15,710	$ 16,298

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Transportation segment revenues from contracts with customers				
Tariff activities:				
Crude oil pipelines	$ 494	$ 412	$ 971	$ 801
NGL pipelines	22	24	50	51
Total tariff activities	516	436	1,021	852
Trucking	35	34	74	68
Total Transportation segment revenues from contracts with customers	$ 551	$ 470	$ 1,095	$ 920

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Facilities segment revenues from contracts with customers				
Crude oil, NGL and other terminalling and storage	$ 177	$ 171	$ 349	$ 337
NGL and natural gas processing and fractionation	87	91	175	191
Rail load / unload	19	16	39	32
Total Facilities segment revenues from contracts with customers	$ 283	$ 278	$ 563	$ 560

Reconciliation to Total Revenues of Reportable Segments. The following table presents the reconciliation of our revenues from contracts with customers to segment revenues and total revenues as disclosed in our Condensed Consolidated Statements of Operations (in millions):

Three Months Ended June 30, 2019	Transportation	Facilities	Supply and Logistics	Total
Revenues from contracts with customers	$ 551	$ 283	$ 7,864	$ 8,698
Other items in revenues	8	8	51	67
Total revenues of reportable segments	$ 559	$ 291	$ 7,915	$ 8,765
Intersegment revenues				(512)
Total revenues				$ 8,253

Three Months Ended June 30, 2018	Transportation	Facilities	Supply and Logistics	Total
Revenues from contracts with customers	$ 470	$ 278	$ 8,124	$ 8,872
Other items in revenues	5	6	(343)	(332)
Total revenues of reportable segments	$ 475	$ 284	$ 7,781	$ 8,540
Intersegment revenues				(460)
Total revenues				$ 8,080

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Six Months Ended June 30, 2019	Transportation	Facilities	Supply and Logistics	Total
Revenues from contracts with customers	$ 1,095	$ 563	$ 15,710	$ 17,368
Other items in revenues	20	26	228	274
Total revenues of reportable segments	$ 1,115	$ 589	$ 15,938	$ 17,642
Intersegment revenues				(1,014)
Total revenues				$ 16,628

Six Months Ended June 30, 2018	Transportation	Facilities	Supply and Logistics	Total
Revenues from contracts with customers	$ 920	$ 560	$ 16,298	$ 17,778
Other items in revenues	9	16	(405)	(380)
Total revenues of reportable segments	$ 929	$ 576	$ 15,893	$ 17,398
Intersegment revenues				(920)
Total revenues				$ 16,478

Minimum Volume Commitments. We have certain agreements that require counterparties to transport or throughput a minimum volume over an agreed upon period. At June 30, 2019 and December 31, 2018, counterparty deficiencies associated with contracts with customers and buy/sell arrangements that include minimum volume commitments totaled $54 million and $62 million, respectively, of which $35 million and $40 million, respectively, was recorded as a contract liability. The remaining balance of $19 million and $22 million at June 30, 2019 and December 31, 2018, respectively, was related to deficiencies for which the counterparties had not met their contractual minimum commitments and were 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 change in the contract liability balance during the six months ended June 30, 2019 (in millions):

	Contract Liabilities
Balance at December 31, 2018	$ 338
Amounts recognized as revenue	(225)
Additions [(1)]	206
Other	(1)
Balance at June 30, 2019	$ 318

(1) Includes approximately $130 million associated with crude oil sales agreements that were entered into in conjunction with storage arrangements and future inventory exchanges. Such amount is expected to be recognized as revenue in the third quarter of 2019. The inventory that has been sold under these agreements is reflected in “Other current assets” on our Condensed Consolidated Balance Sheet until all of our performance obligations are complete.

Remaining Performance Obligations. Topic 606 requires a presentation of information about partially and wholly unsatisfied performance obligations under contracts that exist as of the end of the period. The information includes the amount of consideration allocated to those remaining performance obligations and the timing of revenue recognition of those remaining performance obligations. Certain contracts meet the requirements for the presentation as remaining performance obligations. These arrangements 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. These contracts are all within the scope of Topic 606. 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, 2019 (in millions):

	Remainder of 2019	2020	2021	2022	2023	2024 and Thereafter
Pipeline revenues supported by minimum volume commitments and capacity agreements [1]	$ 79	$ 156	$ 163	$ 159	$ 158	$ 805
Storage, terminalling and throughput agreement revenues	220	361	256	195	160	355
Total	$ 299	$ 517	$ 419	$ 354	$ 318	$ 1,160

(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 Topic 606 or do not meet the requirements for presentation as remaining performance obligations under Topic 606. The following are examples of contracts that are not included in the table above because they are not within the scope of Topic 606 or do not meet the Topic 606 requirements for presentation:

- Minimum volume commitments on certain of our joint venture pipeline systems;
- Acreage dedications — Contracts include those related to the Permian Basin, Eagle Ford, Central, Rocky Mountain and Canada regions;
- Supply and Logistics buy/sell arrangements — Contracts include agreements with future committed volumes on certain Permian Basin, Eagle Ford, Central and Canada region systems;
- All other Supply and Logistics contracts, due to the election of practical expedients related to variable consideration and short-term contracts;
- Transportation and Facilities contracts that are short-term;
- 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. 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 a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At June 30, 2019 and December 31, 2018, substantially all of our trade accounts receivable (net of allowance for doubtful accounts) were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $3 million at both June 30, 2019 and December 31, 2018. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts 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, 2019	December 31, 2018
Trade accounts receivable arising from revenues from contracts with customers	$ 2,563	$ 2,277
Other trade accounts receivables and other receivables [1]	3,722	2,732
Impact due to contractual rights of offset with counterparties	(3,450)	(2,555)
Trade accounts receivable and other receivables, net	$ 2,835	$ 2,454

[1] The balance is comprised primarily of accounts receivable associated with buy/sell arrangements that are not within the scope of Topic 606.

Note 4—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 preferred unitholders and participating securities) by the basic and diluted weighted average number of common units outstanding during the period. Participating securities include LTIP awards that have vested DERs, which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

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. When applying the if-converted method prescribed by FASB guidance, the possible conversion of our Series A preferred units was excluded from the calculation of diluted net income per common unit for the three and six months ended June 30, 2018 as the effect was antidilutive. Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered 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 were deemed to be dilutive during the three and six months ended June 30, 2019 and 2018 were 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. See Note 17 to our Consolidated Financial Statements included in Part IV of our 2018 Annual Report on Form 10-K for a complete discussion of our equity-indexed compensation plan awards.

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,	
	2019	2018	2019	2018
Basic Net Income per Common Unit				
Net income attributable to PAA	$ 446	$ 100	$ 1,416	$ 388
Distributions to Series A preferred unitholders	(37)	(37)	(74)	(74)
Distributions to Series B preferred unitholders	(12)	(12)	(25)	(25)
Distributions to participating securities	(1)	(1)	(2)	(2)
Other	(1)	—	(4)	(1)
Net income allocated to common unitholders [1]	$ 395	$ 50	$ 1,311	$ 286
Basic weighted average common units outstanding	727	725	727	725
Basic net income per common unit	$ 0.54	$ 0.07	$ 1.80	$ 0.39
Diluted Net Income per Common Unit				
Net income attributable to PAA	$ 446	$ 100	$ 1,416	$ 388
Distributions to Series A preferred unitholders	—	(37)	—	(74)
Distributions to Series B preferred unitholders	(12)	(12)	(25)	(25)
Distributions to participating securities	(1)	(1)	(2)	(2)
Other	—	—	—	(1)
Net income allocated to common unitholders [1]	$ 433	$ 50	$ 1,389	$ 286
Basic weighted average common units outstanding	727	725	727	725
Effect of dilutive securities:				
Series A preferred units	71	—	71	—
Equity-indexed compensation plan awards	2	2	2	2
Diluted weighted average common units outstanding	800	727	800	727
Diluted net income per common unit	$ 0.54	$ 0.07	$ 1.74	$ 0.39

(1) We calculate net income allocated to common unitholders based on the distributions pertaining to the current period's net income (whether paid in cash or in-kind). After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to 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 5—Inventory, Linefill and Base Gas and Long-term Inventory

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

	June 30, 2019				December 31, 2018			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]
Inventory								
Crude oil	8,177	barrels	$ 427	$ 52.22	9,657	barrels	$ 367	$ 38.00
NGL	6,887	barrels	117	$ 16.99	10,384	barrels	262	$ 25.23
Other	N/A		14	N/A	N/A		11	N/A
Inventory subtotal			558				640	
Linefill and base gas								
Crude oil	13,325	barrels	766	$ 57.49	13,312	barrels	761	$ 57.17
NGL	1,699	barrels	48	$ 28.25	1,730	barrels	47	$ 27.17
Natural gas	24,976	Mcf	108	$ 4.32	24,976	Mcf	108	$ 4.32
Linefill and base gas subtotal			922				916	
Long-term inventory								
Crude oil	2,448	barrels	126	$ 51.47	1,890	barrels	79	$ 41.80
NGL	1,875	barrels	26	$ 13.87	2,368	barrels	57	$ 24.07
Long-term inventory subtotal			152				136	
Total			$ 1,632				$ 1,692	

[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 6—Goodwill

Goodwill by segment and changes in goodwill are reflected in the following table (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Balance at December 31, 2018	$ 1,040	$ 978	$ 503	$ 2,521
Foreign currency translation adjustments	10	4	2	16
Balance at June 30, 2019	$ 1,050	$ 982	$ 505	$ 2,537

We utilized a quantitative assessment in our goodwill impairment test as of June 30, 2019 and determined that there was no impairment of goodwill.

Note 7—Investments in Unconsolidated Entities

Our investments in unconsolidated entities consisted of the following (in millions, except percentage data):

Entity [1]	Type of Operation	Ownership Interest at June 30, 2019		June 30, 2019	December 31, 2018
Advantage Pipeline Holdings LLC	Crude Oil Pipeline	50%		$ 74	$ 72
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	20%		434	435
Cactus II Pipeline LLC	Crude Oil Pipeline [2]	65%		602	455
Caddo Pipeline LLC	Crude Oil Pipeline	50%		65	65
Capline Pipeline Company LLC	Crude Oil Pipeline [3]	54%		466	—
Cheyenne Pipeline LLC	Crude Oil Pipeline	50%		43	44
Diamond Pipeline LLC	Crude Oil Pipeline	50%		478	479
Eagle Ford Pipeline LLC	Crude Oil Pipeline	50%		386	383
Eagle Ford Terminals Corpus Christi LLC ("Eagle Ford Terminals")	Crude Oil Terminal and Dock [2]	50%		120	108
Midway Pipeline LLC	Crude Oil Pipeline	50%		76	78
Red Oak Pipeline LLC ("Red Oak")	Crude Oil Pipeline [2]	50%		1	—
Saddlehorn Pipeline Company, LLC	Crude Oil Pipeline	40%		223	215
Settoon Towing, LLC	Barge Transportation Services	50%		58	58
STACK Pipeline LLC	Crude Oil Pipeline	50%		117	120
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%		196	190
Wink to Webster Pipeline LLC ("W2W Pipeline")	Crude Oil Pipeline [2]	20%	[4]	38	—
Total investments in unconsolidated entities				$ 3,377	$ 2,702

(1) Except for Eagle Ford Terminals, which is reported in our Facilities segment, the financial results from the entities are reported in our Transportation segment.

(2) Asset is currently under construction by the entity and has not yet been placed in service.

(3) The Capline pipeline was taken out of service in the fourth quarter of 2018. Subsequent to June 30, 2019, the owners of Capline Pipeline Company LLC sanctioned the reversal of the Capline pipeline system.

(4) Subsequent to June 30, 2019, our ownership interest in W2W Pipeline was reduced to 16%, as discussed below.

Formations

Capline LLC. During the first quarter of 2019, the owners of the Capline pipeline system, which originates in St. James, Louisiana and terminates in Patoka, Illinois, contributed their undivided joint interests in the system for equity interests in a legal entity, Capline Pipeline Company LLC ("Capline LLC"). After the contribution, Capline LLC owns 100% of the pipeline system. Each owner's undivided joint interest in the Capline pipeline system prior to the transaction is equal to each owner's equity interest in Capline LLC. Although we own a majority of Capline LLC's equity, we do not have a controlling financial interest in Capline LLC because the other members have substantive participating rights. Therefore, we account for our ownership interest in Capline LLC as an equity method investment.

The transaction resulted in a loss of control of our undivided joint interest, which was derecognized and contributed to Capline LLC. The loss of control required us to measure our equity interest in Capline LLC at fair value. At the time of the transaction, our 54% undivided joint interest in the Capline pipeline system had a carrying value of $177 million, which primarily related to property and equipment included in our Transportation segment. We determined the fair value of our investment in Capline LLC to be approximately $444 million, resulting in the recognition of a gain of $267 million during the six months ended June 30, 2019. Such gain is included in "Gain on investment in unconsolidated entities" on our Condensed Consolidated Statement of Operations.

The fair value of our investment in Capline LLC was based on an income approach utilizing a discounted cash flow analysis. This approach requires us to make long-term forecasts of future revenues and expenditures. Those forecasts require the use of various assumptions and estimates which include those related to the timing and amount of capital expenditures, and the expected tariff rates and volumes of crude oil. These assumptions are based on a potential reversal of the Capline pipeline and the initiation of southbound service on the Capline pipeline from Patoka to St. James, and potential service on our Diamond joint venture pipeline and the Capline pipeline from Cushing, Oklahoma to St. James. We probability weighted various forecasted cash flow scenarios utilized in the analysis when we considered the possible outcomes. We used a discount rate representing our estimate of the risk adjusted discount rate that would be used by market participants. These projects are dependent upon shipper interest. If shipper interest varies from the levels assumed in our model, the related cash flows, and thus the fair value of our investment, could be materially impacted. The fair value of our investment was determined using significant unobservable inputs, or Level 3 inputs in the fair value hierarchy.

W2W Pipeline. In the first quarter of 2019, we announced the formation of W2W Pipeline, a joint venture with subsidiaries of ExxonMobil and Lotus Midstream, LLC. Subsequent to June 30, 2019, three additional entities joined as partners in W2W Pipeline. As a result, our ownership interest in W2W Pipeline decreased from 20% to 16%. We account for our interest in W2W Pipeline under the equity method of accounting. W2W Pipeline is currently developing a new pipeline system that will originate in the Permian Basin in West Texas and transport crude oil to the Texas Gulf Coast. The pipeline system will provide more than 1 million barrels per day of crude oil and condensate capacity, and the project is targeted to commence operations in the first half of 2021.

Red Oak. In June 2019, we announced the formation of Red Oak, a joint venture with a subsidiary of Phillips 66. We own a 50% interest in Red Oak, which is currently developing a new pipeline that will provide crude oil transportation service from Cushing, Oklahoma, and the Permian Basin in West Texas to Corpus Christi, Ingleside, Houston and Beaumont, Texas. Initial service from Cushing to the Gulf Coast is targeted to commence as early as the first quarter of 2021, subject to receipt of applicable permits and regulatory approvals. We account for our interest in Red Oak under the equity method of accounting.

In addition to contributing cash for construction of the Red Oak pipeline system, we have also entered into a pipeline capacity agreement and will be contributing 300,000 barrels of capacity on our Sunrise II pipeline once the Red Oak pipeline system is operational. Once the Red Oak pipeline system is operational, we will record a $160 million increase to our investment in Red Oak associated with our contribution of the capacity and corresponding deferred revenue that will be recognized in revenue on a straight-line basis over the initial term of 33 years.

Note 8—Debt

Debt consisted of the following (in millions):

	June 30, 2019	December 31, 2018
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 3.0% (1)	$ 218	$ —
Senior secured hedged inventory facility, bearing a weighted-average interest rate of 3.5% (1)	100	—
Other	152	66
Total short-term debt	470	66
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $55 and $59, respectively (2)	8,945	8,941
GO Zone term loans, net of debt issuance costs of $1 and $2, respectively, bearing a weighted-average interest rate of 3.2% and 3.1%, respectively	199	198
Other	32	4
Total long-term debt	9,176	9,143
Total debt (3)	$ 9,646	$ 9,209

(1) We classified these commercial paper notes and credit facility borrowings as short-term as of June 30, 2019, as these notes and borrowings were primarily designated as working capital borrowings, were required to be repaid within one year and were primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

(2) As of June 30, 2019, we classified our $500 million, 5.75% senior notes due January 2020 and our $500 million, 2.60% senior notes due December 2019 as long-term, and as of December 31, 2018, we classified our $500 million, 2.60% senior notes due December 2019 as long-term based on our ability and intent to refinance such amounts on a long-term basis.

(3) Our fixed-rate senior notes had a face value of approximately $9.0 billion at both June 30, 2019 and December 31, 2018. We estimated the aggregate fair value of these notes as of June 30, 2019 and December 31, 2018 to be approximately $9.3 billion and $8.6 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. We estimate that the carrying value of outstanding borrowings under our credit facilities, commercial paper program and GO Zone term loans approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities, commercial paper program and GO Zone term loans are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the six months ended June 30, 2019 and 2018 were approximately $4.1 billion and $23.5 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $3.8 billion and $23.6 billion for the six months ended June 30, 2019 and 2018, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

Letters of Credit

In connection with our supply and logistics 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. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At June 30, 2019 and December 31, 2018, we had outstanding letters of credit of $153 million and $184 million, respectively.

Note 9—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, 2018	71,090,468	800,000	726,361,924
Issuances of common units under equity-indexed compensation plans	—	—	423,889
Outstanding at March 31, 2019	71,090,468	800,000	726,785,813
Issuances of common units under equity-indexed compensation plans	—	—	638,806
Outstanding at June 30, 2019	71,090,468	800,000	727,424,619

	Limited Partners		
	Series A Preferred Units	Series B Preferred Units	Common Units
Outstanding at December 31, 2017	69,696,542	800,000	725,189,138
Issuance of Series A preferred units in connection with in-kind distribution	1,393,926	—	—
Issuances of common units under equity-indexed compensation plans	—	—	17,766
Outstanding at March 31, 2018	71,090,468	800,000	725,206,904
Issuances of common units under equity-indexed compensation plans	—	—	375,835
Outstanding at June 30, 2018	71,090,468	800,000	725,582,739

Distributions

Series A Preferred Unit Distributions. The following table details distributions to our Series A preferred unitholders paid during or pertaining to the first six months of 2019 (in millions, except per unit data):

	Series A Preferred Unitholders	
Distribution Payment Date	Cash Distribution	Distribution per Unit
August 14, 2019 [(1)]	$ 37	$ 0.525
May 15, 2019	$ 37	$ 0.525
February 14, 2019	$ 37	$ 0.525

(1) Payable to unitholders of record at the close of business on July 31, 2019 for the period from April 1, 2019 through June 30, 2019. At June 30, 2019, such amount was accrued to distributions payable in "Other current liabilities" on our Condensed Consolidated Balance Sheet.

Series B Preferred Unit Distributions. Distributions on our Series B preferred units are payable semi-annually in arrears on the 15th day of May and November. The following table details distributions paid to our Series B preferred unitholders during the first six months of 2019 (in millions, except per unit data):

	Series B Preferred Unitholders	
Distribution Payment Date	Cash Distribution	Distribution per Unit
May 15, 2019	$ 24.5	$ 30.625

As of June 30, 2019, we had accrued approximately $6 million of distributions payable to our Series B preferred unitholders 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 2019 (in millions, except per unit data):

	Distributions			
	Common Unitholders			
Distribution Payment Date	Public	AAP	Total Cash Distribution	Cash Distribution per Common Unit
August 14, 2019 [(1)]	$ 166	$ 96	$ 262	$ 0.36
May 15, 2019	$ 161	$ 101	$ 262	$ 0.36
February 14, 2019	$ 134	$ 84	$ 218	$ 0.30

(1) Payable to unitholders of record at the close of business on July 31, 2019 for the period from April 1, 2019 through June 30, 2019.

Noncontrolling Interests in Subsidiaries

In May 2019, we formed a joint venture, Red River Pipeline Company LLC ("Red River LLC"), with Delek Logistics Partners, LP ("Delek") on our Red River pipeline system. We received approximately $128 million for Delek's 33% interest in Red River LLC. We consolidate Red River LLC, with Delek's 33% interest accounted for as a noncontrolling interest.

Note 10—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. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on hydrocarbon commodity (referred to herein as "commodity") price changes. We use various derivative instruments to manage our exposure to (i) commodity price risk, as well as to optimize our profits, (ii) interest rate risk and (iii) currency exchange 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 and currency exchange 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. 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.

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 physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities can be divided into the following general categories:

Commodity Purchases and Sales — 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, 2019, net derivative positions related to these activities included:

- A net long position of 5.8 million barrels associated with our crude oil purchases, which was unwound ratably during July 2019 to match monthly average pricing.
- A net short time spread position of 6.0 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through December 2020.
- A net crude oil basis spread position of 36.2 million barrels at multiple locations through December 2021. These derivatives allow us to lock in grade basis differentials.
- A net short position of 5.6 million barrels through December 2021 related to anticipated net sales of crude oil and NGL inventory.

Storage Capacity Utilization — For capacity allocated to our supply and logistics operations, we have utilization risk in a backwardated market structure. As of June 30, 2019, we used derivatives to manage the risk of not utilizing an average of approximately 0.9 million barrels per month of storage capacity through January 2021. These positions involve no outright price exposure, but instead enable us to profitably use the capacity to store hedged crude oil.

Pipeline Loss Allowance Oil — As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor. We utilize derivative instruments to hedge a portion of the anticipated sales of the loss allowance oil that is to be collected under our tariffs. As of June 30, 2019, our PLA hedges included a short position consisting of crude oil futures of 1.3 million barrels through December 2020 and a long call option position of 2.4 million barrels through December 2021.

Natural Gas Processing/NGL Fractionation — 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, 2019:

	Notional Volume (Short)/Long	Remaining Tenor
Natural gas purchases	77.8 Bcf	December 2022
Propane sales	(10.8) MMbls	March 2021
Butane sales	(3.2) MMbls	March 2021
Condensate sales (WTI position)	(1.2) MMbls	March 2021
Power supply requirements (1)	1.1 TWh	December 2022

(1) Power position to hedge a portion of our power supply 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.

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, 2019 (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	12/13/2019	2.34%	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/15/2020	3.06%	Cash flow hedge

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD, we use foreign currency derivatives to minimize the risk of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options.

Our use of foreign currency derivatives include (i) derivatives we use to hedge currency exchange risk created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales and (ii) foreign currency exchange contracts we use to manage our Canadian business cash requirements.

The following table summarizes our open forward exchange contracts as of June 30, 2019 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2019	$ 63	$ 83	$1.00 - $1.32
Forward exchange contracts that exchange USD for CAD:				
	2019	$ 165	$ 220	$1.00 - $1.33

Preferred Distribution Rate Reset Option

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 of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value on our Condensed Consolidated Balance Sheets. Corresponding changes in fair value are recognized in "Other income/(expense), net" in our Condensed Consolidated Statement of Operations. See Note 12 to our Consolidated Financial Statements included in Part IV of our 2018 Annual Report on Form 10-K for additional information regarding our Series A preferred units and Preferred Distribution Rate Reset Option.

Summary of Financial Impact

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 physical transactions are recognized in earnings. Derivatives that are not designated as a hedging instrument and derivatives that do not qualify for hedge accounting 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.

A summary of the impact of our derivatives recognized in earnings is as follows (in millions):

	Three Months Ended June 30, 2019				
Location of Gain/(Loss)	Commodity Derivatives	Foreign Currency Derivatives	Preferred Distribution Rate Reset Option	Interest Rate Derivatives	Total
Supply and Logistics segment revenues [1]	$ 56	$ 2	$ —	$ —	$ 58
Field operating costs [1]	4	—	—	—	4
Interest expense, net [2]	—	—	—	(3)	(3)
Other income/(expense), net [1]	—	—	(7)	—	(7)
Total gain/(loss) on derivatives recognized in net income	$ 60	$ 2	$ (7)	$ (3)	$ 52

	Three Months Ended June 30, 2018				
Location of Gain/(Loss)	Commodity Derivatives	Foreign Currency Derivatives	Preferred Distribution Rate Reset Option	Interest Rate Derivatives	Total
Supply and Logistics segment revenues [1]	$ (339)	$ (6)	$ —	$ —	$ (345)
Interest expense, net [2]	—	—	—	(2)	(2)
Other income/(expense), net [1]	—	—	8	—	8
Total gain/(loss) on derivatives recognized in net income	$ (339)	$ (6)	$ 8	$ (2)	$ (339)

	Six Months Ended June 30, 2019				
Location of Gain/(Loss)	Commodity Derivatives	Foreign Currency Derivatives	Preferred Distribution Rate Reset Option	Interest Rate Derivatives	Total
Supply and Logistics segment revenues [1]	$ 231	$ 7	$ —	$ —	$ 238
Field operating costs [1]	11	—	—	—	11
Interest expense, net [2]	—	—	—	(5)	(5)
Other income/(expense), net [1]	—	—	16	—	16
Total gain/(loss) on derivatives recognized in net income	$ 242	$ 7	$ 16	$ (5)	$ 260

	Six Months Ended June 30, 2018				
Location of Gain/(Loss)	Commodity Derivatives	Foreign Currency Derivatives	Preferred Distribution Rate Reset Option	Interest Rate Derivatives	Total
Supply and Logistics segment revenues [1]	$ (384)	$ (12)	$ —	$ —	$ (396)
Field operating costs [1]	1	—	—	—	1
Interest expense, net [2]	—	—	—	(1)	(1)
Other income/(expense), net [1]	—	—	5	—	5
Total gain/(loss) on derivatives recognized in net income	$ (383)	$ (12)	$ 5	$ (1)	$ (391)

(1) Derivatives not designated as a hedge.

(2) Derivatives in hedging relationships.

The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of June 30, 2019 (in millions):

	Derivatives Not Designated As Hedging Instruments					
Balance Sheet Location	**Commodity Derivatives**	**Foreign Currency Derivatives**	**Preferred Distribution Rate Reset Option**	**Total**	**Interest Rate Derivatives [1]**	**Total Derivatives**
Derivative Assets						
Other current assets	$ 389	$ 4	$ —	$ 393	$ —	$ 393
Other long-term assets, net	37	—	—	37	—	37
Other current liabilities	—	—	—	—	—	—
Other long-term liabilities and deferred credits	6	—	—	6	—	6
Total Derivative Assets	$ 432	$ 4	$ —	$ 436	$ —	$ 436
Derivative Liabilities						
Other current assets	$ (96)	$ (1)	$ —	$ (97)	$ —	$ (97)
Other long-term assets, net	(4)	—	—	(4)	—	(4)
Other current liabilities	(8)	—	—	(8)	(43)	(51)
Other long-term liabilities and deferred credits	(15)	—	(20)	(35)	—	(35)
Total Derivative Liabilities	$ (123)	$ (1)	$ (20)	$ (144)	$ (43)	$ (187)

(1) Derivatives in hedging relationships.

The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of December 31, 2018 (in millions):

	Derivatives Not Designated As Hedging Instruments					
Balance Sheet Location	**Commodity Derivatives**	**Foreign Currency Derivatives**	**Preferred Distribution Rate Reset Option**	**Total**	**Interest Rate Derivatives [1]**	**Total Derivatives**
Derivative Assets						
Other current assets	$ 441	$ —	$ —	$ 441	$ 2	$ 443
Other long-term assets, net	34	—	—	34	—	34
Other long-term liabilities and deferred credits	3	—	—	3	—	3
Total Derivative Assets	$ 478	$ —	$ —	$ 478	$ 2	$ 480
Derivative Liabilities						
Other current assets	$ (182)	$ —	$ —	$ (182)	$ —	$ (182)
Other long-term assets, net	(7)	—	—	(7)	—	(7)
Other current liabilities	(10)	(9)	—	(19)	(1)	(20)
Other long-term liabilities and deferred credits	(9)	—	(36)	(45)	(8)	(53)
Total Derivative Liabilities	$ (208)	$ (9)	$ (36)	$ (253)	$ (9)	$ (262)

(1) Derivatives in hedging relationships.

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.

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):

	June 30, 2019	December 31, 2018
Initial margin	$ 71	$ 95
Variation margin returned	(85)	(91)
Letters of credit	(59)	(84)
Net broker payable	$ (73)	$ (80)

The following table presents information about derivative financial assets and liabilities that are subject to offsetting, including enforceable master netting arrangements (in millions):

	June 30, 2019		December 31, 2018	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 436	$ (187)	$ 480	$ (262)
Netting adjustment	(107)	107	(192)	192
Cash collateral received	(73)	—	(80)	—
Net position - asset/(liability)	$ 256	$ (80)	$ 208	$ (70)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 223	$ —	$ 181	$ —
Other long-term assets, net	33	—	27	—
Other current liabilities	—	(51)	—	(20)
Other long-term liabilities and deferred credits	—	(29)	—	(50)
	$ 256	$ (80)	$ 208	$ (70)

As of June 30, 2019, there was a net loss of $230 million deferred in AOCI. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transactions or (ii) interest expense accruals associated with underlying debt instruments. Of the total net loss deferred in AOCI at June 30, 2019, we expect to reclassify a net loss of $8 million to earnings in the next twelve months. We estimate that substantially all of the remaining deferred loss will be reclassified to earnings through 2050 as the underlying hedged transactions impact earnings. A portion of these amounts is based on market prices as of June 30, 2019; 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,	
	2019	2018	2019	2018
Interest rate derivatives, net	$ (35)	$ 13	$ (58)	$ 45

At June 30, 2019 and December 31, 2018, 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 cleared derivatives as described above, we do not require our non-cleared derivative counterparties to post collateral with us.

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, 2019				Fair Value as of December 31, 2018			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 235	$ 80	$ (6)	$ 309	$ 171	$ 87	$ 12	$ 270
Interest rate derivatives	—	(43)	—	(43)	—	(7)	—	(7)
Foreign currency derivatives	—	3	—	3	—	(9)	—	(9)
Preferred Distribution Rate Reset Option	—	—	(20)	(20)	—	—	(36)	(36)
Total net derivative asset/(liability)	$ 235	$ 40	$ (26)	$ 249	$ 171	$ 71	$ (24)	$ 218

(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, interest rate and foreign currency 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 certain physical commodity contracts, over-the-counter options and the Preferred Distribution Rate Reset Option contained in our partnership agreement which is classified as an embedded derivative.

The fair values of our Level 3 physical commodity contracts and over-the-counter options are based on valuation models utilizing significant timing estimates, which involve management judgment, and pricing inputs from observable and unobservable markets with less volume and transaction frequency than active markets. Significant deviations from these estimates and inputs could result in a material change in fair value. We report unrealized gains and losses associated with these physical commodity contracts in our Condensed Consolidated Statements of Operations as Supply and Logistics segment revenues.

The fair value of the embedded derivative feature contained in our partnership agreement is based on a valuation model that estimates the fair value of the Series A preferred units with and without the Preferred Distribution Rate Reset Option. This model contains inputs, including our common unit price, ten-year U.S. Treasury rates, default probabilities and timing estimates, some of which involve management judgment. A significant change in these inputs could result in a material change in fair value to this embedded derivative feature. We report unrealized gains and losses associated with this embedded derivative in our Condensed Consolidated Statements of Operations in “Other income/(expense), net.”

To the extent any transfers between levels of the fair value hierarchy occur, our policy is to reflect these transfers as of the beginning of the reporting period in which they occur.

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,	
	2019	2018	2019	2018
Beginning Balance	$ (10)	$ (26)	$ (24)	$ (30)
Net gains/(losses) for the period included in earnings	(5)	7	18	5
Settlements	(3)	1	(11)	7
Derivatives entered into during the period	(8)	—	(9)	—
Ending Balance	$ (26)	$ (18)	$ (26)	$ (18)
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	$ (13)	$ 7	$ 9	$ 5

Note 11—Leases

Lessee

We evaluate all agreements entered into or modified after the date of adoption of Topic 842 that convey to us the use of property or equipment for a term to determine whether the agreement is or contains a lease. We lease certain property and equipment under noncancelable and cancelable operating and finance leases. Our operating leases primarily relate to railcars, office space, land, vehicles, and storage tanks, and our finance leases primarily relate to tractor trailers, vehicles and land. For leases with an initial term of greater than 12 months, we recognize a right-of-use asset and lease liability on the balance sheet. Leases with an initial term of 12 months or less are not recorded on the balance sheet. Our lease agreements have remaining lease terms ranging from one year to approximately 60 years. When applicable, this range includes additional terms associated with leases for which we are reasonably certain to exercise the option to renew and such renewal options are recognized as part of our right-of-use assets and lease liabilities. We have renewal options for leases with terms ranging from one year to 40 years that are not recognized as part of our right-of-use assets or lease liabilities as we have determined we are not reasonably certain to exercise the option to renew.

Certain of our leases have variable lease payments, many of which are based on changes in market indices such as the Consumer Price Index. Our lease agreements for our tractor trailers contain residual value guarantees equal to the fair market value of the tractor trailers at the end of the lease term in the event that we elect not to purchase the asset for an amount equal to the fair value. Our lease agreements do not contain any material restrictive covenants.

For determining the present value of lease payments, we use the discount rate implicit in the lease when readily determinable; however, such rate is not readily determinable for most of our leases. For those leases for which the discount rate is not readily determinable, we utilize incremental borrowing rates that reflect collateralized borrowing with payments and terms that mirror our lease portfolio to discount the lease payments based on information available at the lease commencement date.

The following table presents components of lease cost, including both amounts recognized in income and amounts capitalized (in millions):

Lease Cost	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
Operating lease cost	$ 31	$ 63
Short-term lease cost	12	20
Other [1]	—	1
Total lease cost	$ 43	$ 84

(1) Includes immaterial finance lease costs, variable lease costs and sublease income.

The following table presents information related to cash flows arising from lease transactions (in millions):

	Six Months Ended June 30, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows for operating leases	$ 67
Financing cash flows for finance leases	$ 7
Right-of-use assets obtained in exchange for new lease liabilities:	
Operating leases	$ 10

Information related to the weighted-average remaining lease term and discount rate is presented in the table below:

	June 30, 2019
Weighted-average remaining lease term (in years):	
Operating leases	10.0
Finance leases	3.4
Weighted-average discount rate:	
Operating leases	4.5%
Finance leases	2.2%

The following table presents the amount and location of our operating and finance lease right-of-use assets and liabilities on our Condensed Consolidated Balance Sheet (in millions):

Leases	Balance Sheet Location	June 30, 2019
Assets		
Operating lease right-of-use assets	Long-term operating lease right-of-use assets, net	$ 469
Finance lease right-of-use assets	Property and equipment	$ 105
	Accumulated depreciation	(14)
	Property and equipment, net	$ 91
Total lease right-of-use assets		$ 560
Liabilities		
Operating lease liabilities		
Current	Other current liabilities	$ 104
Noncurrent	Long-term operating lease liabilities	370
Total operating lease liabilities		$ 474
Finance lease liabilities		
Current	Short-term debt	$ 19
Noncurrent	Other long-term debt, net	32
Total finance lease liabilities		$ 51
Total lease liabilities		$ 525

The following table presents the maturity of undiscounted cash flows for future minimum lease payments under noncancelable leases as of June 30, 2019 reconciled to our lease liabilities on our Condensed Consolidated Balance Sheet (amounts in millions):

	Operating	Finance
Future minimum lease payments [(1)]:		
Remainder of 2019	$ 62	$ 10
2020	111	16
2021	92	7
2022	78	8
2023	54	5
Thereafter	247	8
Total	644	54
Less: Present value discount	(170)	(3)
Lease liabilities	$ 474	$ 51

(1) Excludes future minimum payments for short-term and other immaterial leases not included on our Condensed Consolidated Balance Sheet.

Lessor

We evaluate all agreements entered into or modified after the date of adoption of Topic 842 that convey to others the use of property or equipment for a term to determine whether the agreement is or contains a lease. Significant judgment is required when determining whether a customer obtains the right to direct the use of identified property or equipment. The underlying assets associated with these agreements are evaluated for future use beyond the lease term.

Our Facilities and Transportation segments enter into agreements to conduct fee-based activities associated with (i) providing storage services primarily for crude oil, NGL and natural gas and (ii) transporting crude oil and NGL. Certain of these agreements convey counterparties the right to direct the operation of physically distinct assets. Such agreements include (i) fixed consideration, which is measured based on an available capacity during the period multiplied by the rate in the agreement, or (ii) a fixed monthly fee and variable consideration based on usage. These agreements often include options to extend or terminate the lease, with advance notice. These agreements are operating leases under Topic 842. For the three and six months ended June 30, 2019, our lease revenue was not material.

The table below presents the maturity of lease payments for operating lease agreements in effect as of June 30, 2019. This presentation includes minimum fixed lease payments and does not include an estimate of variable lease consideration. These agreements have remaining lease terms ranging from two years to 23 years. The following table presents the undiscounted cash flows expected to be received related to these agreements (in millions):

	Remainder of 2019	2020	2021	2022	2023	Thereafter
Lease revenue	$ 9	$ 19	$ 22	$ 25	$ 21	$ 226

Note 12—Related Party Transactions

See Note 16 to our Consolidated Financial Statements included in Part IV of our 2018 Annual Report on Form 10-K for a complete discussion of our related party transactions.

Ownership of PAGP Class C Shares

As of June 30, 2019 and December 31, 2018, we owned 530,053,993 and 516,938,280, respectively, Class C shares of PAGP. The Class C shares represent a non-economic limited partner interest in PAGP that provides us, as the sole holder, a “pass-through” voting right through which our common unitholders and Series A preferred unitholders have the effective right to vote, pro rata with the holders of Class A and Class B shares of PAGP, for the election of eligible PAGP GP directors.

Transactions with Other Related Parties

Our other related parties include (i) principal owners and their affiliated entities and (ii) entities in which we hold investments and account for under the equity method of accounting (see Note 7 for additional information regarding such entities). We recognize as our principal owners entities that have a designated representative on the board of directors of PAGP GP and/or own greater than 10% of the limited partner interests in AAP. Such limited partner interests in AAP translates into a significantly smaller indirect ownership interest in PAA. As of June 30, 2019, our principal owners include Oxy and Kayne Anderson Capital Advisors, L.P. We also consider subsidiaries or funds identified as affiliated with such entities to be related parties. Through various transactions by an affiliate of The Energy & Minerals Group (“EMG”) in May 2019, EMG’s limited partner interest in AAP was significantly reduced, which caused EMG to lose its right to designate a representative on the board of directors of PAGP GP. Following these transactions, we no longer recognize EMG as a principal owner.

During the three and six months ended June 30, 2019 and 2018, we recognized sales and transportation revenues, purchased petroleum products and utilized transportation services from our principal owners and their affiliated entities and our equity method investees. These transactions were conducted at posted tariff rates or prices that we believe approximate market. Included in these transactions was a crude oil buy/sell agreement that includes a multi-year minimum volume commitment. 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,	
	2019	2018	2019	2018
Revenues from related parties [1] [2]	$ 231	$ 284	$ 456	$ 566
Purchases and related costs from related parties [2]	$ (14)	$ 68	$ 100	$ 160

(1) A majority of these revenues are included in “Supply and Logistics segment revenues” on our Condensed Consolidated Statements of Operations.

(2) Crude oil purchases that are part of inventory exchanges under buy/sell transactions are netted with the related sales, with any margin presented in “Purchases and related costs” in our Condensed Consolidated Statements of Operations.

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

	June 30, 2019	December 31, 2018
Trade accounts receivable and other receivables, net from related parties [1] [2]	$ 285	$ 144
Trade accounts payable to related parties [1] [2] [3]	$ 80	$ 121

(1) We have a netting arrangement with certain related parties. Receivables and payables are presented net of such amounts.

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

(3) We have an agreement to transport crude oil at posted tariff rates on a pipeline that is owned by an equity method investee, in which we own a 50% interest. Our commitment to transport is supported by crude oil buy/sell agreements with third parties (including Oxy) with commensurate quantities.

Note 13—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. 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.

Taking into account what we believe to be all relevant known facts and circumstances, and based on what we believe to be reasonable assumptions regarding the application of those facts and circumstances to existing laws and regulations, we do not believe that the outcome of the legal proceedings in which we are currently involved (including those described below) will, individually or in the aggregate, have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Environmental — General

Although over the course of the last several years we have made significant investments in our maintenance and integrity programs, and have hired additional personnel in those areas, 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. 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 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 June 30, 2019, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident, as discussed further below) totaled $143 million, of which $64 million was classified as short-term and $79 million was classified as long-term. At December 31, 2018, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident) totaled $135 million, of which $43 million was classified as short-term and $92 million was classified as long-term. Such short- and long-term environmental liabilities are reflected in “Other current liabilities” and “Other long-term liabilities and deferred credits,” respectively, on our Condensed Consolidated Balance Sheets. At June 30, 2019, we had recorded receivables totaling $74 million for amounts probable of recovery under insurance and from third parties under indemnification agreements, of which $43 million was classified as short-term and $31 million was classified as long-term. At December 31, 2018, we had recorded $61 million of such receivables, of which $28 million was classified as short-term and $33 million was classified as long-term. Such short- and long-term receivables are reflected in “Trade accounts receivable and other receivables, net” and “Other long-term assets, net,” respectively, 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 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, 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. We may be subject to additional claims, investigations and lawsuits, which could materially impact the liabilities and costs we currently expect to incur as a result of the Line 901 incident. Set forth below is a brief summary of actions and matters that are currently pending:

On May 21, 2015, we received a corrective action order from the United States Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (“PHMSA”), the governmental agency with jurisdiction over the operation of Line 901 as well as over a second stretch of pipeline extending from Gaviota Pump Station in Santa Barbara County to Emidio Pump Station in Kern County, California (Line 903), requiring us to shut down, purge, review, remediate and test Line 901. The corrective action order was subsequently amended on June 3, 2015; November 13, 2015; and June 16, 2016 to require us to take additional corrective actions with respect to both Lines 901 and 903 (as amended, the “CAO”). Among other requirements, the CAO obligated us to conduct a root cause failure analysis with respect to Line 901 and present remedial work plans and restart plans to PHMSA prior to returning Line 901 and 903 to service; the CAO also imposed a pressure restriction on the section of Line 903 between Pentland Pump Station and Emidio Pump Station and required us to take other specified actions with respect to both Lines 901 and 903. We intend to continue to comply with the CAO and to cooperate with any other governmental investigations relating to or arising out of the release. Excavation and removal of the affected section of the pipeline was completed on May 28, 2015. Line 901 and Line 903 have been purged and are not currently operational, with the exception of the Pentland to Emidio segment of Line 903, which remains in service under a pressure restriction. No timeline has been established for the restart of Line 901 or Line 903.

On February 17, 2016, PHMSA issued a Preliminary Factual Report of the Line 901 failure, which contains PHMSA’s preliminary findings regarding factual information about the events leading up to the accident and the technical analysis that has been conducted to date. On May 19, 2016, PHMSA issued its final Failure Investigation Report regarding the Line 901 incident. PHMSA’s findings indicate that the direct cause of the Line 901 incident was external corrosion that thinned the pipe wall to a level where it ruptured suddenly and released crude oil. PHMSA also concluded that there were numerous contributory causes of the Line 901 incident, including ineffective protection against external corrosion, failure to detect and mitigate the corrosion and a lack of timely detection and response to the rupture. The report also included copies of various engineering and technical reports regarding the incident. By virtue of its statutory authority, PHMSA has the power and authority to impose fines and penalties on us and cause civil or criminal charges to be brought against us. While to date PHMSA has not imposed any such fines or penalties or brought any such civil or criminal charges with respect to the Line 901 release, their investigation is still open and we are likely to have fines or penalties imposed upon us, and we may have civil or criminal charges brought against us, in the future.

In late May of 2015, the California Attorney General's Office and the District Attorney's office for the County of Santa Barbara (collectively, the "Prosecutors") began investigating the Line 901 incident to determine whether any applicable state or local laws had been violated. On May 16, 2016, PAA and one of its employees were 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. The May 2016 Indictment included a total of 46 counts against PAA. On July 28, 2016, at an arraignment hearing held in California Superior Court in Santa Barbara County, PAA pled not guilty to all counts. Between May of 2016 and May of 2018, 31 of the criminal charges against PAA (including one felony charge) and all of the criminal charges against our employee, were dismissed. The remaining 15 charges were the subject of a jury trial in California Superior Court in Santa Barbara County that began in May of 2018. 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 jury deadlocked on three counts (including two felony discharge counts and one strict liability animal takings count), and two misdemeanor discharge counts were dropped. 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. The Superior Court also indicated that it would conduct further hearings on the issue of whether there were any "direct victims" of the spill that are entitled to restitution under applicable law. We do not anticipate that the victim restitution, if any, imposed as a result of these proceedings will have a material adverse impact on the financial position or operations of the Partnership. In April of 2019, the Prosecutors announced their intent to re-try the two felony discharge counts for which no jury verdict was returned. The strict liability animal taking count for which no jury verdict was returned has been dismissed. We do not believe that a conviction on either or both counts can result in the imposition of any additional fines, penalties, or other punishment, under the California penal code. As such, we have filed a motion to vacate the trial.

Also in late May of 2015, the United States Attorney for the Department of Justice, Central District of California, Environmental Crimes Section ("DOJ") began an investigation into whether there were any violations of federal criminal statutes in connection with the Line 901 incident, including potential violations of the federal Clean Water Act. We have cooperated with the DOJ's investigation by responding to their requests for documents and access to our employees. Consistent with the terms of our governing organizational documents, we are funding our employees' defense costs, including the costs of separate counsel engaged to represent such individuals. On August 26, 2015, we received a Request for Information from the EPA relating to Line 901. We have provided various responsive materials to date and we will continue to do so in the future in cooperation with the EPA. Except in connection with the May 2016 Indictment and the 2019 Sentence, to date no civil enforcement actions or criminal charges with respect to the Line 901 release have been brought against PAA or any of its affiliates, officers or employees by PHMSA, the DOJ, the EPA, the California Attorney General or the California Department of Fish and Wildlife, and no fines or penalties have been imposed by such governmental agencies; however, the investigations being conducted by such agencies are still open and we may have fines or penalties imposed upon us, our officers or our employees in the future, or civil actions or criminal charges brought against us, our officers or our employees in the future, whether by those or other governmental agencies.

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 have received a number of claims through the claims line and we have been processing those claims and making payments as appropriate. In addition, we have also had nine class action lawsuits filed against us, six of which have been administratively consolidated into a single proceeding in the United States District Court for the Central District of California. In general, the plaintiffs are seeking to establish different classes of claimants that have allegedly been damaged by the release. To date, the court has certified three sub-classes of claimants and denied certification of the other proposed sub-class. On appeal, the Ninth Circuit Court of Appeals overturned the certification of the oil-industry sub-class, so the remaining sub-classes that have been certified include (i) commercial fishermen who landed fish in certain specified fishing blocks in the waters adjacent to Santa Barbara County or persons or businesses who resold commercial seafood landed in such areas; and (ii) beachfront property and easement owners whose properties were oiled. We are also defending a separate class action lawsuit proceeding in the United States District Court for the Central District of California brought on behalf of the Line 901 and Line 903 easement holders seeking injunctive relief as well as compensatory damages.

There were also two securities law class action lawsuits filed on behalf of certain purported investors in the Partnership and/or PAGP against the Partnership, PAGP and/or certain of their respective officers, directors and underwriters. Both of these lawsuits were consolidated into a single proceeding in the United States District Court for the Southern District of Texas. In general, these lawsuits alleged that the various defendants violated securities laws by misleading investors regarding the integrity of the Partnership's pipelines and related facilities through false and misleading statements, omission of material facts and concealing of the true extent of the spill. The plaintiffs claimed unspecified damages as a result of the reduction in value of their investments in the Partnership and PAGP, which they attributed to the alleged wrongful acts of the defendants. The Partnership and PAGP, and the other defendants, denied the allegations in, and moved to dismiss these lawsuits. On March 29, 2017, the Court ruled in our favor dismissing all claims against all defendants. Plaintiffs refiled their complaint. On April 2, 2018, the Court dismissed all of the refiled claims against all defendants with prejudice. Plaintiffs appealed the dismissal, and on July 16, 2019 the Fifth Circuit Court of Appeals affirmed the dismissal. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we indemnified and funded the defense costs of our officers and directors in connection with this lawsuit; we also indemnified and funded the defense costs of our underwriters pursuant to the terms of the underwriting agreements we previously entered into with such underwriters.

In addition, four unitholder derivative lawsuits have been filed by certain purported investors in the Partnership against the Partnership, certain of its affiliates and certain officers and directors. One lawsuit was filed in State District Court in Harris County, Texas and subsequently dismissed by the Court. Two of these lawsuits were filed in the United States District Court for the Southern District of Texas and were administratively consolidated into one action and later dismissed on the basis that Plains Partnership agreements require that derivative suits be filed in Delaware Chancery Court. Following the order dismissing the Texas Federal Court suits, a new derivative suit brought by different plaintiffs was filed in Delaware Chancery Court and subsequently dismissed without prejudice. Plaintiffs amended and refiled their complaint on June 3, 2019. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we are indemnifying and funding the defense costs of our officers and directors in connection with these lawsuits.

We have also received several other individual lawsuits and complaints from companies, governmental agencies and individuals alleging damages arising out of the Line 901 incident. These lawsuits and claims generally seek compensatory and punitive damages, and in some cases permanent injunctive relief.

In addition to the foregoing, 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, and we also have exposure to the payment of additional fines, penalties and costs under other applicable federal, state and local laws, statutes and regulations. To the extent any such costs are reasonably estimable, we have included an estimate of such costs in the loss accrual described below.

Taking the foregoing into account, as of June 30, 2019, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $380 million, which estimate includes actual and projected emergency response and clean-up costs, natural resource damage assessments and certain third party claims settlements, as well as estimates for fines, penalties and certain legal fees. 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 duration of the natural resource damage assessment process and the ultimate amount of damages determined, (ii) 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, (iii) the determination and calculation of fines and penalties, but excluding fines and penalties that are not probable or reasonably estimable and (iv) 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, the amount of time it takes for us to resolve all of the current and future lawsuits, claims and investigations 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. In addition, with respect to fines and penalties, the ultimate amount of any fines and penalties assessed against us depends on a wide variety of factors, many of which are not estimable at this time. Where fines and penalties are probable and estimable, we have included them in our estimate, although such estimates could turn out to be wrong. 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.

As of June 30, 2019, we had a remaining undiscounted gross liability of $88 million related to this event, of which approximately $55 million is presented in “Other current liabilities” on our Condensed Consolidated Balance Sheet, with the remainder presented in “Other long-term liabilities and deferred credits.” We maintain insurance coverage, which is subject to certain exclusions and deductibles, in the event of such environmental liabilities. Subject to such exclusions and deductibles, we believe that our coverage is adequate to cover the current estimated total emergency response and clean-up costs, claims settlement costs and remediation costs and we believe that this coverage is also adequate to cover any potential increase in the estimates for these costs that exceed the amounts currently identified. Through June 30, 2019, we had collected, subject to customary reservations, $188 million out of the approximate $255 million of release costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of June 30, 2019, we have recognized a receivable of approximately $67 million for the portion of the release costs that we believe is probable of recovery from insurance, net of deductibles and amounts already collected. Of this amount, approximately $38 million is recognized as a current asset in “Trade accounts receivable and other receivables, net” on our Condensed Consolidated Balance Sheet, with the remainder in “Other long-term assets, net.” 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 costs associated with restoration of the impacted areas, as well as natural resource damage assessment and compensation, legal, professional and regulatory costs, in addition to fines and penalties, during future periods.

Note 14—Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. See Note 3 to our Consolidated Financial Statements included in Part IV of our 2018 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 investment.

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 our proportionate share of the depreciation and amortization expense of, and gains and losses on significant asset sales by, unconsolidated entities, and further adjusted 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 related to investing activities (such as the purchase of linefill) 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. Segment Adjusted EBITDA excludes depreciation and amortization.

Maintenance capital consists of 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.

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

Three Months Ended June 30, 2019	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Revenues:					
External customers [1]	$ 316	$ 151	$ 7,914	$ (128)	$ 8,253
Intersegment [2]	243	140	1	128	512
Total revenues of reportable segments	$ 559	$ 291	$ 7,915	$ —	$ 8,765
Equity earnings in unconsolidated entities	$ 83	$ —	$ —		$ 83
Segment Adjusted EBITDA	$ 410	$ 172	$ 200		$ 782
Maintenance capital	$ 39	$ 30	$ 3		$ 72

Three Months Ended June 30, 2018	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Revenues:					
External customers [1]	$ 264	$ 147	$ 7,781	$ (112)	$ 8,080
Intersegment [2]	211	137	—	112	460
Total revenues of reportable segments	$ 475	$ 284	$ 7,781	$ —	$ 8,540
Equity earnings in unconsolidated entities	$ 96	$ —	$ —		$ 96
Segment Adjusted EBITDA	$ 360	$ 171	$ (26)		$ 505
Maintenance capital	$ 32	$ 26	$ 5		$ 63

Six Months Ended June 30, 2019	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Revenues:					
External customers [1]	$ 618	$ 307	$ 15,936	$ (233)	$ 16,628
Intersegment [2]	497	282	2	233	1,014
Total revenues of reportable segments	$ 1,115	$ 589	$ 15,938	$ —	$ 17,642
Equity earnings in unconsolidated entities	$ 172	$ —	$ —		$ 172
Segment Adjusted EBITDA	$ 809	$ 356	$ 478		$ 1,643
Maintenance capital	$ 67	$ 46	$ 5		$ 118

Six Months Ended June 30, 2018	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Revenues:					
External customers [1]	$ 517	$ 288	$ 15,892	$ (219)	$ 16,478
Intersegment [2]	412	288	1	219	920
Total revenues of reportable segments	$ 929	$ 576	$ 15,893	$ —	$ 17,398
Equity earnings in unconsolidated entities	$ 171	$ —	$ —		$ 171
Segment Adjusted EBITDA	$ 695	$ 357	$ 45		$ 1,097
Maintenance capital	$ 61	$ 41	$ 6		$ 108

(1) Transportation revenues from External customers include certain inventory exchanges with our customers where our Supply and Logistics segment has transacted the inventory exchange and serves as the shipper on our pipeline systems. See Note 3 to our Consolidated Financial Statements included in Part IV of our 2018 Annual Report on Form 10-K for a discussion of our related accounting policy. We have included an estimate of the revenues from these inventory exchanges in our Transportation segment revenues from External customers presented above and adjusted those revenues out such that Total revenues from External customers reconciles to our Condensed Consolidated Statements of Operations. This presentation is consistent with the information provided to our CODM.

(2) Segment revenues include intersegment amounts that are eliminated in Purchases and related costs and Field operating costs in our Condensed Consolidated Statements of Operations. 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,	
	2019	2018	2019	2018
Segment Adjusted EBITDA	$ 782	$ 505	$ 1,643	$ 1,097
Adjustments [1]:				
Depreciation and amortization of unconsolidated entities [2]	(14)	(14)	(27)	(29)
Gains/(losses) from derivative activities, net of inventory valuation adjustments [3]	(44)	(240)	30	(216)
Long-term inventory costing adjustments [4]	(25)	(5)	(4)	7
Deficiencies under minimum volume commitments, net [5]	(1)	(3)	7	(13)
Equity-indexed compensation expense [6]	(4)	(12)	(7)	(23)
Net gain/(loss) on foreign currency revaluation [7]	(7)	2	(12)	(8)
Line 901 incident [8]	(10)	—	(10)	—
Depreciation and amortization	(147)	(130)	(283)	(256)
Gains/(losses) on asset sales and asset impairments, net	4	81	—	81
Gain on investment in unconsolidated entities	—	—	267	—
Interest expense, net	(103)	(111)	(203)	(217)
Other income/(expense), net	(6)	11	18	10
Income before tax	425	84	1,419	433
Income tax (expense)/benefit	23	16	(1)	(45)
Net income	448	100	1,418	388
Net income attributable to noncontrolling interests	(2)	—	(2)	—
Net income attributable to PAA	$ 446	$ 100	$ 1,416	$ 388

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

(2) Includes our proportionate share of the depreciation and amortization of, and gains and losses on significant asset sales by, 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 the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining Segment Adjusted EBITDA. In addition, we exclude gains and losses on derivatives that are related to investing activities, such as the purchase of linefill. 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 writedowns of such inventory that result from price declines from Segment Adjusted EBITDA.

(5) We 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) Includes equity-indexed compensation expense associated with awards that will or may be settled in units.

(7) Includes gains and losses realized on the settlement of foreign currency transactions as well as the revaluation of monetary assets and liabilities denominated in a foreign currency.

(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 13 for additional information regarding the Line 901 incident.

Note 15—Income Taxes

All of our Canadian operations are conducted by entities that are treated as corporations for Canadian tax purposes (flow through for U.S. income tax purposes) and that are subject to Canadian federal and provincial taxes. During the second quarter of 2019, the Alberta government enacted legislation that reduces the Alberta provincial corporate income tax rate from 12% to 8% over the period from July 1, 2019 through January 1, 2022. As a result, at June 30, 2019, we recognized a reduction of our deferred income tax liability of approximately $60 million and a corresponding deferred tax benefit.

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 2018 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
- Acquisitions and Capital Projects
- Results of Operations
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates
- Other Items
- Forward-Looking Statements

Executive Summary

Company Overview

We own and operate midstream energy infrastructure and provide logistics services primarily for crude oil, NGL and natural gas. 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. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: Transportation, Facilities and Supply and Logistics. See "—Results of Operations—Analysis of Operating Segments" for further discussion.

Overview of Operating Results, Capital Investments and Other Significant Activities

During the first six months of 2019, we recognized net income of $1.418 billion as compared to net income of $388 million recognized during the first six months of 2018. The increase in net income over the comparative periods was driven by:

- Favorable results from our Supply and Logistics segment due to favorable crude oil differentials, primarily in the Permian Basin and Canada, higher NGL margins and more favorable impacts in the 2019 period from the mark-to-market of certain derivative instruments;

- Favorable results from our Transportation segment, primarily from our pipelines in the Permian Basin region, driven by higher volumes from increased production and our recently completed capital expansion projects;

- A non-cash gain of $267 million recognized in the current period related to a fair value adjustment resulting from the accounting for the contribution of our undivided joint interest in the Capline pipeline system for an equity interest in Capline Pipeline Company LLC; and

- Lower income tax expense primarily due to the impact of the reduction of the provincial income tax rate in Alberta, Canada enacted during the second quarter of 2019 and lower year-over-year income as impacted by fluctuations in the derivative mark-to-market valuations in our Canadian operations, partially offset by higher income tax expense as a result of higher taxable earnings from our Canadian operations; partially offset by

- Higher depreciation and amortization expense primarily due to additional depreciation expense associated with the completion of various capital expansion projects; and

- The unfavorable impact to the 2019 comparative period of a net gain on asset sales and asset impairments of $81 million for six months ended June 30, 2018.

See further discussion of our operating results in the "—Results of Operations—Analysis of Operating Segments" and "—Other Income and Expenses" sections below.

We invested $695 million in midstream infrastructure projects during the six months ended June 30, 2019, and we expect expansion capital for the full year of 2019 to be approximately $1.5 billion, primarily related to projects under development in the Permian Basin. See the "—Acquisitions and Capital Projects" section below for additional information.

During 2019, we also announced the formation of several strategic joint ventures, including Wink to Webster Pipeline LLC, Red Oak Pipeline LLC and Red River Pipeline Company LLC. See Note 7 and Note 9 to our Condensed Consolidated Financial Statements for additional information.

We paid approximately $480 million of cash distributions to our common unitholders during the six months ended June 30, 2019. We also paid cash distributions of approximately $74 million to our Series A preferred unitholders, and we paid a semi-annual cash distribution of $24.5 million to our Series B preferred unitholders. In July 2019, we declared quarterly cash distributions of $0.36 per common unit (a total distribution of $262 million) and $0.525 per Series A preferred unit (a total distribution of $37 million) to be paid on August 14, 2019.

Leverage Reduction Plan Completion and Financial Policy Update

In August 2017, we announced that we were implementing an action plan to strengthen our balance sheet, reduce leverage, enhance our distribution coverage, minimize new issuances of common equity and position the Partnership for future distribution growth. The action plan ("Leverage Reduction Plan"), which was endorsed by the PAGP GP Board, included our intent to achieve certain objectives. During 2017 and 2018, we made meaningful progress in executing our Leverage Reduction Plan and in April 2019, we announced our achievement of the remaining objectives. Concurrent with the completion of the Leverage Reduction Plan, we completed a review of our approach to our capital allocation process, targeted leverage metrics and distribution management policies. As part of the April 2019 announcement, we provided several updates regarding our financial policy, including the following actions:

- Lowering our targeted long-term debt to Adjusted EBITDA leverage ratio by 0.5x to a range of 3.0x to 3.5x;

- Establishing a long-term sustainable minimum annual distribution coverage level of 130% underpinned by predominantly fee-based cash flows; and

- Our adoption of an annual cycle for setting the common unit distribution level and intention to increase common unit distributions in the future contingent on achieving and maintaining targeted leverage and coverage ratios and subject to an annual review process.

These actions reflect our dedication to optimizing sustainable unitholder value while also preserving and enhancing our financial flexibility, further reducing leverage and improving our credit profile, with an objective of achieving mid-BBB equivalent credit ratings over time. Consistent with those objectives, we announced that we intend to continue to focus on activities to enhance investment returns and reinforce capital discipline through asset optimization, joint ventures, potential divestitures and similar arrangements.

Acquisitions and Capital Projects

The following table summarizes our expenditures for acquisition capital, expansion capital and maintenance capital (in millions):

	Six Months Ended June 30,	
	2019	2018
Acquisition capital	$ 47	$ —
Expansion capital [1] [2]	695	832
Maintenance capital [2]	118	108
	$ 860	$ 940

(1) Contributions to unconsolidated entities related to expansion projects of such entities are recognized in "Expansion capital." We account for our investments in such entities under the equity method of accounting.

(2) Capital expenditures made to expand the existing operating and/or earnings capacity of our assets are classified as expansion capital. 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 are classified as maintenance capital.

Expansion Capital Projects

The following table summarizes our notable projects in progress during 2019 and the estimated cost for the year ending December 31, 2019 (in millions):

Projects	2019
Permian Basin Takeaway Pipeline Projects	$ 570
Complementary Permian Basin Projects	485
Selected Facilities	105
Other Long-Haul Pipeline Projects	100
Other Projects	240
Total Projected 2019 Expansion Capital Expenditures [1]	$ 1,500

(1) Amounts reflect our expectation that certain projects will be owned in a joint venture structure with a proportionate share of the project cost dispersed among the partners.

Results of Operations

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	
	2019	2018	$	%	2019	2018	$	%
Transportation Segment Adjusted EBITDA [1]	$ 410	$ 360	$ 50	14 %	$ 809	$ 695	$ 114	16 %
Facilities Segment Adjusted EBITDA [1]	172	171	1	1 %	356	357	(1)	— %
Supply and Logistics Segment Adjusted EBITDA [1]	200	(26)	226	**	478	45	433	**
Adjustments:								
Depreciation and amortization of unconsolidated entities	(14)	(14)	—	— %	(27)	(29)	2	7 %
Selected items impacting comparability - Segment Adjusted EBITDA	(91)	(258)	167	**	4	(253)	257	**
Depreciation and amortization	(147)	(130)	(17)	(13)%	(283)	(256)	(27)	(11)%
Gains/(losses) on asset sales and asset impairments, net	4	81	(77)	(95)%	—	81	(81)	(100)%
Gain on investment in unconsolidated entities	—	—	—	N/A	267	—	267	N/A
Interest expense, net	(103)	(111)	8	7 %	(203)	(217)	14	6 %
Other income/(expense), net	(6)	11	(17)	**	18	10	8	**
Income tax (expense)/benefit	23	16	7	44 %	(1)	(45)	44	98 %
Net income	448	100	348	348 %	1,418	388	1,030	265 %
Net income attributable to noncontrolling interests	(2)	—	(2)	N/A	(2)	—	(2)	N/A
Net income attributable to PAA	$ 446	$ 100	$ 346	346 %	$ 1,416	$ 388	$ 1,028	265 %
Basic net income per common unit	$ 0.54	$ 0.07	$ 0.47	**	$ 1.80	$ 0.39	$ 1.41	**
Diluted net income per common unit	$ 0.54	$ 0.07	$ 0.47	**	$ 1.74	$ 0.39	$ 1.35	**
Basic weighted average common units outstanding	727	725	2	**	727	725	2	**
Diluted weighted average common units outstanding	800	727	73	**	800	727	73	**

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

(1) Segment Adjusted EBITDA is the measure of segment performance that is utilized by our CODM to assess performance and allocate resources among our operating segments. This measure is adjusted for certain items, including those that our CODM believes impact comparability of results across periods. See Note 14 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

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. The primary additional measures used by management are earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization of, and gains and losses on significant asset sales by, unconsolidated entities), gains and losses on asset sales and asset impairments and gains on investments in unconsolidated entities, adjusted for certain selected items impacting comparability (“Adjusted EBITDA”) and implied distributable cash flow (“DCF”).

Management believes that the presentation of such additional financial measures 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 measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) gains or losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), the mark-to-market related to our Preferred Distribution Rate Reset Option, gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and business outlook 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. 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, expansion projects and numerous other factors as discussed, as applicable, in “Analysis of Operating Segments.”

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA and Implied DCF are reconciled to Net Income, the most directly comparable measure as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Condensed Consolidated Financial Statements and footnotes.

The following table sets forth the reconciliation of these non-GAAP financial performance measures from Net income (in millions):

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	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
	2019	2018	$	%	2019	2018	$	%
Net income	$ 448	$ 100	$ 348	348 %	$ 1,418	$ 388	$ 1,030	265 %
Add/(Subtract):								
Interest expense, net	103	111	(8)	(7)%	203	217	(14)	(6)%
Income tax expense/(benefit)	(23)	(16)	(7)	(44)%	1	45	(44)	(98)%
Depreciation and amortization	147	130	17	13 %	283	256	27	11 %
(Gains)/losses on asset sales and asset impairments, net	(4)	(81)	77	95 %	—	(81)	81	100 %
Gain on investment in unconsolidated entities	—	—	—	N/A	(267)	—	(267)	N/A
Depreciation and amortization of unconsolidated entities (1)	14	14	—	— %	27	29	(2)	(7)%
Selected Items Impacting Comparability:								
(Gains)/losses from derivative activities, net of inventory valuation adjustments (2)	44	240	(196)	**	(30)	216	(246)	**
Long-term inventory costing adjustments (3)	25	5	20	**	4	(7)	11	**
Deficiencies under minimum volume commitments, net (4)	1	3	(2)	**	(7)	13	(20)	**
Equity-indexed compensation expense (5)	4	12	(8)	**	7	23	(16)	**
Net (gain)/loss on foreign currency revaluation (6)	7	(2)	9	**	12	8	4	**
Line 901 incident (7)	10	—	10	**	10	—	10	**
Selected Items Impacting Comparability - Segment Adjusted EBITDA	91	258	(167)	**	(4)	253	(257)	**
(Gains)/losses from derivative activities (2)	7	(8)	15	**	(15)	(5)	(10)	**
Net (gain)/loss on foreign currency revaluation (6)	1	(2)	3	**	—	(4)	4	**
Selected Items Impacting Comparability - Adjusted EBITDA (8)	99	248	(149)	**	(19)	244	(263)	**
Adjusted EBITDA (8)	$ 784	$ 506	$ 278	55 %	$ 1,646	$ 1,098	$ 548	50 %
Interest expense, net of certain non-cash items (9)	(98)	(107)	9	8 %	(194)	(212)	18	8 %
Maintenance capital (10)	(72)	(63)	(9)	(14)%	(118)	(108)	(10)	(9)%
Current income tax expense	(24)	(7)	(17)	(243)%	(53)	(20)	(33)	(165)%
Adjusted equity earnings in unconsolidated entities, net of distributions (11)	—	1	(1)	**	1	15	(14)	**
Implied DCF	$ 590	$ 330	260	79 %	$ 1,282	$ 773	509	66 %
Preferred unit distributions (12)	(62)	(62)	—	— %	(99)	(62)	(37)	(60)%
Implied DCF Available to Common Unitholders	$ 528	$ 268	$ 260	97 %	$ 1,183	$ 711	$ 472	66 %
Common unit cash distributions (13)	(262)	(218)			(480)	(435)		
Implied DCF Excess/(Shortage) (14)	$ 266	$ 50			$ 703	$ 276		

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

(1) Over the past several years, we have increased our participation in strategic pipeline joint ventures accounted for under the equity method of accounting. We exclude our proportionate share of the depreciation and amortization expense of, and gains and losses on significant asset sales by, such unconsolidated entities when reviewing Adjusted EBITDA, similar to our consolidated assets.

(2) 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 of operations, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining Adjusted EBITDA. In addition, we exclude gains and losses on derivatives that are related to investing activities, such as the purchase of linefill. We also exclude the impact of corresponding inventory valuation adjustments, as applicable, as well as the mark-to-market adjustment related to our Preferred Distribution Rate Reset Option. See Note 10 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities and our Preferred Distribution Rate Reset Option.

(3) 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 treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and writedowns of such inventory that result from price declines as a selected item impacting comparability. See Note 5 to our Consolidated Financial Statements included in Part IV of our 2018 Annual Report on Form 10-K for additional inventory disclosures.

(4) We 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. We believe the inclusion of the contractually committed revenues associated with that period is meaningful to investors 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.

(5) Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted net income per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted net income per unit calculation, as applicable, and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability. See Note 17 to our Consolidated Financial Statements included in Part IV of our 2018 Annual Report on Form 10-K for a comprehensive discussion regarding our equity-indexed compensation plans.

(6) During the periods presented, there were fluctuations in the value of CAD to USD, resulting in non-cash gains and losses that were not related to our core operating results for the period and were thus classified as a selected item impacting comparability. See Note 10 to our Condensed Consolidated Financial Statements for discussion regarding our currency exchange rate risk hedging activities.

(7) 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 13 to our Condensed Consolidated Financial Statements for additional information regarding the Line 901 incident.

(8) Other income/(expense), net per 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.

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

(10) 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.

(11) Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization and gains and losses on significant asset sales).

(12) Cash distributions paid to our preferred unitholders during the period presented. The current $0.5250 quarterly ($2.10 annualized) per unit distribution requirement of our Series A preferred units was paid-in-kind for each quarterly distribution from their issuance through February 2018. Distributions on our Series A preferred units have been paid in cash since the May 2018 quarterly distribution. The current $61.25 per unit annual distribution requirement of our Series B preferred units, which were issued in October 2017, is payable semi-annually in arrears on May 15 and November 15. See Note 12 to our Consolidated Financial Statements included in Part IV of our 2018 Annual Report on Form 10-K for additional information regarding our preferred units.

(13) Cash distributions paid during the period presented.

(14) Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes. DCF shortages may be funded from previously established reserves, cash on hand or from borrowings under our credit facilities or commercial paper program.

Analysis of Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our CODM (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Adjusted EBITDA, segment volumes, Segment Adjusted EBITDA per barrel and maintenance capital investment.

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 our proportionate share of the depreciation and amortization expense of, and gains and losses on significant asset sales by, unconsolidated entities, and further adjusted for certain selected items including (i) the mark-to-market of 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 related to investing activities (such as the purchase of linefill) 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 applicable amounts subsequently recognized into revenue and (v) other items that our CODM believes are integral to understanding our core segment operating performance. See Note 14 to our Condensed Consolidated Financial Statements for a reconciliation of Segment Adjusted EBITDA to Net income attributable to PAA.

Revenues and expenses from our Canadian based subsidiaries, which use CAD as their functional currency, are translated at the prevailing average exchange rates for the month.

Transportation Segment

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. The Transportation segment generates revenue through a combination of tariffs, pipeline capacity agreements and other transportation fees. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment results generated by our tariff and other fee-related activities depend on the volumes transported on the pipeline and the level of the tariff and other fees charged, as well as the fixed and variable field costs of operating the pipeline.

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

Operating Results (1)	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
(in millions, except per barrel data)	2019	2018	$	%	2019	2018	$	%
Revenues	$ 559	$ 475	$ 84	18 %	$ 1,115	$ 929	$ 186	20 %
Purchases and related costs	(48)	(46)	(2)	(4)%	(100)	(92)	(8)	(9)%
Field operating costs	(186)	(157)	(29)	(18)%	(360)	(304)	(56)	(18)%
Segment general and administrative expenses (2)	(27)	(30)	3	10 %	(54)	(58)	4	7 %
Equity earnings in unconsolidated entities	83	96	(13)	(14)%	172	171	1	1 %
Adjustments (3):								
Depreciation and amortization of unconsolidated entities	14	14	—	— %	27	29	(2)	(7)%
(Gains)/losses from derivative activities	2	—	2	N/A	2	(1)	3	**
Deficiencies under minimum volume commitments, net	1	1	—	**	(7)	9	(16)	**
Equity-indexed compensation expense	2	7	(5)	**	4	12	(8)	**
Line 901 incident	10	—	10	**	10	—	10	**
Segment Adjusted EBITDA	$ 410	$ 360	$ 50	14 %	$ 809	$ 695	$ 114	16 %
Maintenance capital	$ 39	$ 32	$ 7	22 %	$ 67	$ 61	$ 6	10 %
Segment Adjusted EBITDA per barrel	$ 0.66	$ 0.68	$ (0.02)	(3)%	$ 0.67	$ 0.69	$ (0.02)	(3)%

Average Daily Volumes (in thousands of barrels per day) (4)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Variance Volumes	Variance %	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Variance Volumes	Variance %
Tariff activities volumes								
Crude oil pipelines (by region):								
Permian Basin (5)	4,575	3,734	841	23 %	4,423	3,489	934	27 %
South Texas / Eagle Ford (5)	448	434	14	3 %	454	428	26	6 %
Central (5)	525	448	77	17 %	517	445	72	16 %
Gulf Coast	147	170	(23)	(14)%	152	187	(35)	(19)%
Rocky Mountain (5)	313	270	43	16 %	307	263	44	17 %
Western	195	181	14	8 %	188	177	11	6 %
Canada	319	298	21	7 %	321	308	13	4 %
Crude oil pipelines	6,522	5,535	987	18 %	6,362	5,297	1,065	20 %
NGL pipelines	182	171	11	6 %	196	172	24	14 %
Tariff activities total volumes	6,704	5,706	998	17 %	6,558	5,469	1,089	20 %
Trucking volumes	83	91	(8)	(9)%	88	95	(7)	(7)%
Transportation segment total volumes	6,787	5,797	990	17 %	6,646	5,564	1,082	19 %

** 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 14 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

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

(5) Region includes volumes (attributable to our interest) from pipelines owned by unconsolidated entities.

The following is a discussion of items impacting Transportation segment operating results for the periods indicated.

Revenues, Purchases and Related Costs, Equity Earnings in Unconsolidated Entities and Volumes. The following table presents variances in revenues, purchases and related costs and equity earnings in unconsolidated entities by region for the comparative periods presented:

	Favorable/(Unfavorable) Variance Three Months Ended June 30, 2019-2018			Favorable/(Unfavorable) Variance Six Months Ended June 30, 2019-2018		
(in millions)	Revenues	Purchases and Related Costs	Equity Earnings	Revenues	Purchases and Related Costs	Equity Earnings
Permian Basin region	$ 54	$ (1)	$ (18)	$ 120	$ (3)	$ (30)
South Texas / Eagle Ford region	(2)	—	3	(1)	—	24
Central region	7	—	2	23	—	7
Gulf Coast region	1	—	(6)	—	—	(10)
Rocky Mountain region	(1)	—	5	(5)	—	9
Canada region	9	—	—	13	—	—
Other regions, trucking and pipeline loss allowance revenue	16	(1)	1	36	(5)	1
Total variance	$ 84	$ (2)	$ (13)	$ 186	$ (8)	$ 1

- *Permian Basin region.* The increase in revenues, net of purchases and related costs, of approximately $53 million and $117 million for the three and six months ended June 30, 2019, respectively, compared to the three and six months ended June 30, 2018 was primarily due to higher volumes from increased production and our recently completed capital expansion projects. These increases for the three and six month comparative periods included (i) higher volumes on our gathering systems of approximately 279,000 and 290,000 barrels per day, respectively, (ii) higher volumes of approximately 390,000 and 450,000 barrels per day, respectively, on our intra-basin pipelines and (iii) a volume increase of approximately 172,000 and 194,000, respectively, on our long-haul pipelines, including our Sunrise II pipeline, which was placed in service in the fourth quarter of 2018.

  The decrease in equity earnings for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily due to the sale of a 30% interest in BridgeTex Pipeline Company, LLC in the third quarter of 2018.

- *South Texas / Eagle Ford region.* The increase in equity earnings for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was from our 50% interest in Eagle Ford Pipeline LLC and was primarily due to higher volumes. The six month comparative period was also favorably impacted by the recognition of revenue associated with deficiencies under minimum volume commitments.

- *Central region.* The increase in revenues for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily due to higher volumes on certain of our pipelines in the Central region, including our Red River pipeline. Additionally, the six-month 2019 period was favorably impacted by the recognition of previously deferred revenue in the first quarter of 2019.

  The increase in equity earnings for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily from our 50% interests in Diamond Pipeline LLC ("Diamond Pipeline"), Caddo Pipeline LLC and Midway Pipeline LLC and was due to higher volumes related to increased refinery demand. Subsequent to June 30, 2019, the owners of Diamond Pipeline sanctioned an expansion and an extension of the pipeline to connect to the Capline pipeline.

- *Gulf Coast region.* The decrease in volumes in the Gulf Coast region for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 were associated with (i) a lower tariff pipeline, which did not result in a significant impact on revenue and (ii) the Capline pipeline being taken out of service in the fourth quarter of 2018. Subsequent to June 30, 2019, the owners of Capline Pipeline Company LLC sanctioned the reversal of the Capline pipeline system and a connection to Diamond Pipeline.

In the first quarter of 2019, the owners of the Capline pipeline system contributed their undivided joint interests in the system for equity interests in a legal entity. As a result, revenues and expenses from the Capline pipeline system that were previously consolidated are reflected as equity earnings. The unfavorable equity earnings variance for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was due to our share of operating costs from our 54.13% interest in Capline Pipeline Company LLC reflected in equity earnings in the 2019 periods, whereas such costs were reflected in field operating costs in the 2018 periods.

- *Rocky Mountain region.* The decrease in revenues for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily due to the sale of certain of our assets in the Rocky Mountain region in May of 2018.

  The increase in equity earnings for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily from our 40% interest in Saddlehorn Pipeline Company, LLC and was due to higher volumes from committed shippers.

- *Canada region.* The increase in revenues for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily due to higher tariffs on certain of our Canadian crude oil pipelines and related system assets, partially offset by unfavorable foreign exchange impacts.

- *Other regions, trucking and pipeline loss allowance revenue.* The increase in other net revenues for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily due to greater loss allowance revenue in the 2019 periods driven by higher volumes.

Adjustments: Deficiencies under minimum volume commitments, net. Many industry infrastructure projects developed and completed over the last several years were underpinned by long-term minimum volume commitment contracts whereby the shipper agreed to either: (i) ship and pay for certain stated volumes or (ii) pay the agreed upon price for a minimum contract quantity. Some of these agreements include make-up rights if the minimum volume is not met. If a counterparty has a make-up right associated with a deficiency, we bill the counterparty and defer the revenue attributable to the counterparty’s make-up right but record an adjustment to reflect such amount associated with the current period activity in Segment Adjusted EBITDA. We subsequently recognize the revenue, and record a corresponding reversal of the adjustment, 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.

For the three months ended June 30, 2019 and the three and six months ended June 30, 2018, amounts billed to counterparties exceeded revenue recognized during the period that was previously deferred. For the six months ended June 30, 2019, the recognition of previously deferred revenue exceeded amounts billed to counterparties associated with deficiencies under minimum volume commitments.

Field Operating Costs. The increase in field operating costs for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily due to (i) the impact of an increase of estimated costs recognized in the second quarter of 2019 associated with the Line 901 incident (which impact our field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above) (see Note 13 to our Condensed Consolidated Financial Statements for additional information regarding the Line 901 incident), (ii) an increase in power related costs, resulting from higher volumes and (iii) an increase in property taxes related to new assets placed in service and (iv) an increase in performance-based compensation costs. Overall increases in field operating costs also resulted from expansion projects placed in service since June 30, 2018, including our Sunrise II pipeline expansion within the Permian Basin region, which was placed in service in late 2018. The increase in field operating costs for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was partially offset by the favorable impact of reflecting operating costs associated with the Capline pipeline system in equity earnings for the 2019 periods that were included in field operating costs for the 2018 periods, as discussed above.

Segment general and administrative expenses. The decrease in segment general and administrative expenses for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily due to a decrease in equity-indexed compensation expense due to fewer awards outstanding in 2019. A portion of equity-indexed compensation expense was associated with awards that will or may be settled in common units (which impact our segment general and administrative expenses but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above).

Maintenance Capital. Maintenance capital consists of 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. The increase in maintenance capital for the three and six months ended June 30, 2019 compared to the same periods in 2018 was primarily due to the timing of projects in our integrity management program.

Facilities Segment

Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services primarily for crude oil, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. The Facilities segment generates revenue through a combination of month-to-month and multi-year agreements and processing arrangements.

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

Operating Results (1)	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
(in millions, except per barrel data)	2019	2018	$	%	2019	2018	$	%
Revenues	$ 291	$ 284	$ 7	2 %	$ 589	$ 576	$ 13	2 %
Purchases and related costs	(4)	(3)	(1)	(33)%	(7)	(8)	1	13 %
Field operating costs	(88)	(92)	4	4 %	(175)	(176)	1	1 %
Segment general and administrative expenses (2)	(21)	(21)	—	— %	(41)	(42)	1	2 %
Adjustments (3):								
Gains from derivative activities	(7)	(1)	(6)	**	(11)	(2)	(9)	**
Deficiencies under minimum volume commitments, net	—	2	(2)	**	—	4	(4)	**
Equity-indexed compensation expense	1	2	(1)	**	1	5	(4)	**
Segment Adjusted EBITDA	$ 172	$ 171	$ 1	1 %	$ 356	$ 357	$ (1)	— %
Maintenance capital	$ 30	$ 26	$ 4	15 %	$ 46	$ 41	$ 5	12 %
Segment Adjusted EBITDA per barrel	$ 0.46	$ 0.46	$ —	— %	$ 0.48	$ 0.48	$ —	— %

	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
Volumes (4)	2019	2018	Volumes	%	2019	2018	Volumes	%
Liquids storage (average monthly capacity in millions of barrels)	109	109	—	— %	109	109	—	— %
Natural gas storage (average monthly working capacity in billions of cubic feet) (5)	63	65	(2)	(3)%	63	66	(3)	(5)%
NGL fractionation (average volumes in thousands of barrels per day)	137	132	5	4 %	147	135	12	9 %
Facilities segment total volumes (average monthly volumes in millions of barrels) (6)	124	124	—	— %	124	124	—	— %

** 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 14 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

(4) Average monthly volumes are calculated as total volumes for the period divided by the number of months in the period.

(5) The decrease in average monthly working capacity of natural gas storage facilities was driven by adjustments for the net capacity change between capacity additions from fill and dewater operations and capacity losses from salt creep.

(6) Facilities segment total volumes is calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

The following is a discussion of items impacting Facilities segment operating results for the periods indicated.

Revenues, Purchases and Related Costs and Volumes. The following summarizes the significant drivers of variances in revenues, purchases and related costs and volumes for the comparative periods:

- *Crude Oil Storage.* Revenues increased by $6 million and $12 million for the three and six months ended June 30, 2019, respectively, compared to the three and six months ended June 30, 2018 due to increased activity at certain of our terminals, primarily our Cushing terminal, and the addition of 1.0 million barrels of storage capacity at our Midland terminal placed into service in the fourth quarter of 2018 and the first quarter of 2019.

- *Rail Terminals.* Revenues increased by $6 million and $12 million for the three and six months ended June 30, 2019, respectively, compared to the three and six months ended June 30, 2018, primarily due to increased activity at our St. James rail terminal.

- *Natural Gas Storage.* Revenues, net of purchases and related costs, were relatively flat for the three months ended June 30, 2019 compared to the three months ended June 30, 2018. Revenues, net of purchases and related costs, increased by $5 million for the six months ended June 30, 2019 compared to the six months ended June 30, 2018, primarily due to expiring contracts replaced by contracts with higher rates and increased hub activity.

- *NGL Operations.* Revenues decreased by $5 million and $16 million for the three and six months ended June 30, 2019, respectively, compared to the three and six months ended June 30, 2018, primarily due to a net unfavorable foreign exchange impact of approximately $4 million and $10 million, respectively. The six-month comparative period was further unfavorably impacted by the sale of a natural gas processing facility in the second quarter of 2018.

Field Operating Costs. The decrease in field operating costs for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily related to a decrease in power-related costs associated with derivative activities (which impact our field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above), partially offset by increased personnel costs, including higher costs at our rail terminals as a result of increased activity.

Maintenance Capital. For the three and six months ended June 30, 2019 as compared to the three and six months ended June 30, 2018, maintenance capital spending increased primarily due to the impact of higher expenditures related to cavern maintenance at certain of our gas storage facilities.

Supply and Logistics Segment

Revenues from our Supply and Logistics segment activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes. Generally, our segment results are impacted by (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchases volumes and NGL sales volumes), (ii) the overall strength, weakness and volatility of market conditions, including regional differentials, and the allocation of our assets among our various risk management strategies and (iii) the effects of competition on our lease gathering and NGL margins. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets.

The following tables set forth our operating results from our Supply and Logistics segment:

Operating Results (1)	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
(in millions, except per barrel data)	2019	2018	$	%	2019	2018	$	%
Revenues	$ 7,915	$ 7,781	$ 134	2 %	$ 15,938	$ 15,893	$ 45	— %
Purchases and related costs	(7,700)	(7,959)	259	3 %	(15,262)	(15,884)	622	4 %
Field operating costs	(70)	(66)	(4)	(6)%	(139)	(131)	(8)	(6)%
Segment general and administrative expenses (2)	(27)	(29)	2	7 %	(56)	(59)	3	5 %
Adjustments (3):								
(Gains)/losses from derivative activities, net of inventory valuation adjustments	49	241	(192)	**	(21)	219	(240)	**
Long-term inventory costing adjustments	25	5	20	**	4	(7)	11	**
Equity-indexed compensation expense	1	3	(2)	**	2	6	(4)	**
Net (gain)/loss on foreign currency revaluation	7	(2)	9	**	12	8	4	**
Segment Adjusted EBITDA	$ 200	$ (26)	$ 226	**	$ 478	$ 45	$ 433	**
Maintenance capital	$ 3	$ 5	$ (2)	(40)%	$ 5	$ 6	$ (1)	(17)%
Segment Adjusted EBITDA per barrel	$ 1.74	$ (0.24)	$ 1.98	**	$ 1.95	$ 0.19	$ 1.76	**

Average Daily Volumes (4)	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
(in thousands of barrels per day)	2019	2018	Volumes	%	2019	2018	Volumes	%
Crude oil lease gathering purchases	1,102	1,028	74	7 %	1,115	1,030	85	8 %
NGL sales	158	174	(16)	(9)%	242	266	(24)	(9)%
Supply and Logistics segment total volumes	1,260	1,202	58	5 %	1,357	1,296	61	5 %

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

(1) Revenues and costs 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 14 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

(4) Average daily volumes are calculated as the total volumes for the period divided by the number of days in the period.

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

	NYMEX WTI Crude Oil Price	
	Low	**High**
Three months ended June 30, 2019	$ 51	$ 66
Three months ended June 30, 2018	$ 62	$ 74
Six months ended June 30, 2019	$ 46	$ 66
Six months ended June 30, 2018	$ 59	$ 74

Our crude oil and NGL supply, logistics and distribution operations 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 for both sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. Additionally, net revenues were impacted by net gains and losses from certain derivative activities during the periods.

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.

Segment Adjusted EBITDA and Volumes. The following summarizes the significant items impacting our Supply and Logistics segment operating results for the comparative periods:

- *Crude Oil Operations.* Net revenues from our crude oil supply and logistics operations increased for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 largely due to favorable differentials, primarily in the Permian Basin and Canada.

- *NGL Operations.* Net revenues from our NGL operations increased for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 primarily due to the streamlining of our NGL activities by focusing on our equity supply from our gathering and processing facilities, favorable regional differentials and the favorable impact of certain non-recurring items recorded in the second quarter of 2019.

- *Impact from Certain Derivative Activities Net of Inventory Valuation Adjustments.* The impact from certain derivative activities on our net revenues includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in another period (or the reversal of mark-to-market gains and losses from a prior period), losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable. See Note 10 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities. These gains and losses impact our net revenues but are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above.

- *Long-Term Inventory Costing Adjustments.* Our net revenues are impacted by changes in the weighted average cost of our crude oil and NGL inventory pools that result from price movements during the periods. These costing adjustments related to long-term inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that was 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. These costing adjustments impact our net revenues but are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above.

- *Foreign Exchange Impacts.* Our net revenues are impacted by fluctuations in the value of CAD to USD, resulting in foreign exchange gains and losses on U.S. denominated net assets within our Canadian operations. These non-cash gains and losses impact our net revenues but are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above.

- *Field Operating Costs.* The increase in field operating costs for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily driven by an increase in trucking costs resulting from higher third-party hauled volumes, partially offset by a decrease in vehicle expense related to the adoption of the new lease accounting standard.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense increased for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 largely driven by (i) additional depreciation expense associated with the completion of various capital expansion projects and (ii) an adjustment to the useful lives of certain assets.

Gains/Losses on Asset Sales and Asset Impairments, Net

The net gain on asset sales and asset impairments for the three and six months ended June 30, 2018 was largely driven by a gain on the sale of certain pipelines in the Rocky Mountain region, partially offset by a loss on the sale of a non-core asset under construction.

Gain on Investment in Unconsolidated Entities

During the six months ended June 30, 2019, we recognized a non-cash gain of $267 million related to a fair value adjustment resulting from the accounting for the contribution of our undivided joint interest in the Capline pipeline system for an equity interest in Capline Pipeline Company LLC. See Note 7 to our Condensed Consolidated Financial Statements for additional information.

Interest Expense

The decrease in interest expense for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily due to (i) a lower weighted average debt balance during the 2019 periods from lower commercial paper and credit facility borrowings and (ii) higher capitalized interest in the 2019 periods due to additional projects under construction.

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,	
	2019	**2018**	**2019**	**2018**
Gain/(loss) related to mark-to-market adjustment of our Preferred Distribution Rate Reset Option [(1)]	$ (7)	$ 8	$ 16	$ 5
Other	1	3	2	5
	$ (6)	$ 11	$ 18	$ 10

(1) See Note 10 to our Condensed Consolidated Financial Statements for additional information.

Income Tax Expense

The change in income tax for the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018 was primarily due to the recognition of a deferred tax benefit of $60 million as a result of the reduction of the provincial tax rate in Alberta, Canada enacted during the second quarter of 2019, the impact on income of fluctuations in the derivative mark-to-market valuations in our Canadian operations and higher current income tax expense as a result of higher taxable earnings from our Canadian operations.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities, (ii) borrowings under our credit facilities or commercial paper program and (iii) funds received from sales of equity and debt securities. In addition, we may supplement these sources of liquidity with proceeds from our divestiture program, as further discussed below in the section entitled "—Acquisitions and Capital Expenditures." 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, other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under our commercial paper program or credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing our long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional equity or debt securities and the sale of assets.

As of June 30, 2019, although we had a working capital deficit of $12 million, we had approximately $2.9 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, 2019
Availability under senior unsecured revolving credit facility (1) (2)	$	1,460
Availability under senior secured hedged inventory facility (1) (2)		1,287
Amounts outstanding under commercial paper program		(218)
Subtotal		2,529
Cash and cash equivalents		419
Total	$	2,948

(1) Represents availability prior to giving effect to borrowings outstanding under our commercial paper program, which reduce available capacity under the 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 $140 million and $13 million, respectively.

We believe that we have, and will continue to have, the ability to access the 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 liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. In addition, usage of our credit facilities, which provide the financial backstop for our commercial paper program, is subject to ongoing compliance with covenants. As of June 30, 2019, we were in compliance with all such covenants. Also, see Item 1A. "Risk Factors" included in our 2018 Annual Report on Form 10-K for further discussion regarding such risks that may impact our liquidity and capital resources.

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 2018 Annual Report on Form 10-K.

Net cash provided by operating activities for the first six months of 2019 and 2018 was $1.464 billion and $1.015 billion, respectively, and primarily resulted from earnings from our operations. Additionally, as discussed further below, changes during these periods in our inventory levels and associated margin balances required as part of our hedging activities impacted our cash flow from operating activities.

During the six months ended June 30, 2019, our cash provided by operating activities was positively impacted by decreases in the volume of inventory that we held, primarily due to the sale of NGL and crude oil inventory. The favorable effects from liquidation of such inventory were partially offset by timing of revenue recognized during the period for which cash was received in prior periods.

During the six months ended June 30, 2018, net cash provided by operating activities was positively impacted by approximately $300 million of cash received for transactions for which the revenue had been deferred pending the completion of future performance obligations. That positive impact was partially offset by increases in the margin balances required as part of our hedging activities, which were funded by short-term debt.

Acquisitions and Capital Expenditures

In addition to our operating needs discussed above, we also use cash for our acquisition activities and expansion capital projects and maintenance capital activities. Historically, we have financed these expenditures primarily with cash generated by operating activities and the financing activities discussed in "—Equity and Debt Financing Activities" below. In recent years, we have also used proceeds from our divestiture program.

Acquisitions. During the second quarter of 2019, we paid an aggregate of $47 million to acquire assets, including a crude oil storage terminal.

Capital Projects. We invested approximately $695 million in midstream infrastructure during the six months ended June 30, 2019, and we expect to invest approximately $1.5 billion during the full year ending December 31, 2019. See "—Acquisitions and Capital Projects" for detail of our projected capital expenditures for the year ending December 31, 2019. We expect to fund our 2019 capital program with retained cash flow, proceeds from assets sold as part of our divestiture program or debt.

In the first quarter of 2019, we announced the formation of W2W Pipeline, a joint venture with subsidiaries of ExxonMobil and Lotus Midstream, LLC. Subsequent to June 30, 2019, three additional entities joined as partners in W2W Pipeline. As a result, our ownership interest in W2W Pipeline decreased from 20% to 16%. W2W Pipeline is currently developing a new pipeline system that will originate in the Permian Basin in West Texas and transport crude oil to the Texas Gulf Coast. The pipeline system will provide more than 1 million barrels per day of crude oil and condensate capacity, and the project is targeted to commence operations in the first half of 2021. See Note 7 to our Condensed Consolidated Financial Statements for additional information.

During the second quarter of 2019, we announced the formation of Red Oak, a joint venture with a subsidiary of Phillips 66. We own a 50% interest in Red Oak, which is currently developing a new pipeline that will provide crude oil transportation service from Cushing, Oklahoma, and the Permian Basin in West Texas to Corpus Christi, Ingleside, Houston and Beaumont, Texas. Initial service from Cushing to the Gulf Coast is targeted to commence as early as the first quarter of 2021, subject to receipt of applicable permits and regulatory approvals. See Note 7 to our Condensed Consolidated Financial Statements for additional information.

Divestitures. During the second quarter of 2019, we formed a joint venture, Red River LLC, with Delek on our Red River pipeline system. We received approximately $128 million for Delek's 33% interest in Red River LLC. See Note 9 to our Condensed Consolidated Financial Statements for additional information.

Ongoing Acquisition, Divestiture and Investment Activities. We intend to continue to focus on activities to enhance investment returns and reinforce capital discipline through asset optimization, joint ventures, potential divestitures and similar arrangements. We typically do not announce a transaction until after we have executed a definitive agreement. However, 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 acquisition or investment efforts will be successful, or that our strategic asset divestitures will be completed. Although we expect the acquisitions and investments we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized. Also, see Item 1A. "Risk Factors—Risks Related to Our Business" of our 2018 Annual Report on Form 10-K for further discussion regarding risks related to our acquisitions and divestitures.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding expansion 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. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities or commercial paper program and other debt agreements, as well as payment of distributions to our unitholders.

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 an aggregate of $1.1 billion of debt or equity securities ("Traditional Shelf"). At June 30, 2019, we had approximately $1.1 billion of unsold securities available under the Traditional Shelf. 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, 2019.

Credit Agreements, Commercial Paper Program and Indentures. 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 our GO Zone term loans 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. As of June 30, 2019, we were in compliance with the covenants contained in our credit agreements and indentures.

During the six months ended June 30, 2019, we had net borrowings under our credit facilities and commercial paper program of $318 million. These borrowings resulted primarily from funds needed for general partnership purposes.

During the six months ended June 30, 2018, we had net repayments on our credit facilities and commercial paper program of $72 million. The net repayments resulted primarily from cash flow from operating activities, partially offset by borrowings during the period related to funding needs for inventory purchases and related margin activities.

Distributions to Our Unitholders

Distributions to our Series A preferred unitholders. On August 14, 2019, we will pay a cash distribution of $37 million ($0.525 per unit) on our Series A preferred units outstanding as of July 31, 2019, the record date for such distribution for the period from April 1, 2019 through June 30, 2019. See Note 9 to our Condensed Consolidated Financial Statements for details of distributions made during or pertaining to the first six months of 2019.

Distributions to Series B preferred unitholders. Distributions on our Series B preferred units are payable semi-annually in arrears on the 15th day of May and November. See Note 9 to our Condensed Consolidated Financial Statements for additional information.

Distributions to our common unitholders. In accordance with our partnership agreement, after making distributions to holders of our outstanding preferred units, we distribute the remainder of our available cash to common unitholders of record within 45 days following the end of each quarter. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. Our levels of financial reserves are established by our general partner and include reserves for the proper conduct of our business (including future capital expenditures and anticipated credit needs), compliance with law or contractual obligations and funding of future distributions to our Series A and Series B preferred unitholders. Our available cash also includes cash on hand resulting from borrowings made after the end of the quarter. On August 14, 2019, we will pay a quarterly distribution of $0.36 per common unit ($1.44 per common unit on an annualized basis) on our common units outstanding as of July 31, 2019, the record date for such distribution for the period from April 1, 2019 through June 30, 2019. See Note 9 to our Condensed Consolidated Financial Statements for details of distributions paid during or pertaining to the first six months of 2019. Also, see Item 5. "Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities—Cash Distribution Policy" included in our 2018 Annual Report on Form 10-K for additional discussion regarding distributions.

We believe that 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. A prolonged material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Contingencies

For a discussion of contingencies that may impact us, see Note 13 to our Condensed Consolidated Financial Statements.

Commitments

Contractual 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 ten 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. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with our counterparties (including giving effect to netting buy/sell contracts and those subject to a net settlement arrangement). 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 well as other amounts due under the specified contractual obligations as of June 30, 2019 (in millions):

	Remainder of 2019	2020	2021	2022	2023	2024 and Thereafter	Total
Long-term debt and related interest payments (1)	$ 709	$ 878	$ 949	$ 1,079	$ 1,599	$ 8,593	$ 13,807
Leases (2)	72	127	99	86	59	255	698
Other obligations (3)	522	863	509	255	230	1,152	3,531
Subtotal	1,303	1,868	1,557	1,420	1,888	10,000	18,036
Crude oil, NGL and other purchases (4)	4,622	5,955	5,554	5,280	4,865	10,602	36,878
Total	$ 5,925	$ 7,823	$ 7,111	$ 6,700	$ 6,753	$ 20,602	$ 54,914

(1) Includes debt service payments, interest payments due on senior notes and the commitment fee on assumed available capacity under our credit facilities, as well as long-term borrowings under our credit agreements and commercial paper program, if any. Although there may be short-term borrowings under our credit agreements and commercial paper program, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the credit agreements or commercial paper program) in the amounts above. For additional information regarding our debt obligations, see Note 8 to our Condensed Consolidated Financial Statements.

(2) Includes both operating and finance leases as defined by FASB guidance. Leases are primarily for (i) railcars, (ii) office space, (iii), land, (iv) vehicles, (v) storage tanks and (vi) tractor trailers. See Note 11 to our Condensed Consolidated Financial Statements for additional information.

(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements (including certain agreements for which the amount and timing of expected payments is subject to the completion of underlying construction projects), (iii) certain rights-of-way easements and (iv) noncancelable commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity method investments. The transportation agreements include approximately $1.7 billion associated with agreements to transport crude oil at posted tariff rates on pipelines that are owned by equity method investees. Our commitment to transport is supported by crude oil buy/sell or other agreements with third parties (including Oxy) with commensurate quantities.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during June 2019. 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 supply and logistics 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. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At June 30, 2019 and December 31, 2018, we had outstanding letters of credit of approximately $153 million and $184 million, respectively.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For a discussion regarding our critical accounting policies and estimates, see “Critical Accounting Policies and Estimates” under Item 7 of our 2018 Annual Report on Form 10-K.

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:

- 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, whether due to declines in production from existing oil and gas reserves, reduced demand, failure to develop or slowdown in the development of additional oil and gas reserves, whether from reduced cash flow to fund drilling or the inability to access capital, or other factors;
- the effects of competition, including the effects of capacity overbuild in areas where we operate;
- market distortions caused by over-commitments to infrastructure projects, which impacts volumes, margins, returns and overall earnings;
- unanticipated changes in crude oil and NGL market structure, grade differentials and volatility (or lack thereof);
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, NGL and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event, including cyber or other attacks on our electronic and computer systems;
- failure to implement or capitalize, or delays in implementing or capitalizing, on expansion projects, whether due to permitting delays, permitting withdrawals or other factors;
- shortages or cost increases of supplies, materials or labor;
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;
- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- the currency exchange rate of the Canadian dollar;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;

- 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;
- non-utilization of our assets and facilities;
- increased costs, or lack of availability, of insurance;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the effectiveness of our risk management activities;
- 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, including our ability to satisfy our contractual obligations to our customers;
- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

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 2018 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 (i) commodity price risk, (ii) interest rate risk and (iii) currency exchange 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 Supply and Logistics and Transportation segments. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory, basis differentials and storage capacity utilization. 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 Supply and Logistics and Facilities segments. Our objectives for these derivatives include hedging anticipated purchases of natural gas. 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 Supply and Logistics segment. 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 10 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, 2019 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	$ 237	$ (14)	$ 20
Natural gas	(16)	$ 9	$ (9)
NGL and other	88	$ (34)	$ 34
Total fair value	$ 309		

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. Our variable rate debt outstanding at June 30, 2019, approximately $518 million, was subject to interest rate re-sets that generally range from one day to approximately one month. The average interest rate on variable rate debt that was outstanding during the six months ended June 30, 2019 was 3.3%, based upon rates in effect during such period. The fair value of our interest rate derivatives was a liability of $43 million as of June 30, 2019. A 10% increase in the forward LIBOR curve as of June 30, 2019 would have resulted in an increase of $19 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of June 30, 2019 would have resulted in a decrease of $19 million to the fair value of our interest rate derivatives. See Note 10 to our Condensed Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives was an asset of $3 million as of June 30, 2019. A 10% increase in the exchange rate (USD-to-CAD) would have resulted in a decrease of $10 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would have resulted in an increase of $10 million to the fair value of our foreign currency derivatives. See Note 10 to our Condensed Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

Preferred Distribution Rate Reset Option

The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value in our Condensed Consolidated Balance Sheets. The valuation model utilized for this embedded derivative contains inputs including our common unit price, ten-year U.S. treasury rates, default probabilities and timing estimates to ultimately calculate the fair value of our Series A preferred units with and without the Preferred Distribution Rate Reset Option. The fair value of this embedded derivative was a liability of $20 million as of June 30, 2019. A 10% increase or decrease in the fair value would have an impact of $2 million. See Note 10 to our Condensed Consolidated Financial Statements for a discussion of embedded derivatives.

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, 2019, 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. We implemented new processes and internal controls in connection with our adoption on January 1, 2019 of FASB accounting standard ASU 2016-02, *Leases (Topic 842)*, and we also implemented a new lease accounting system during the second quarter of 2019.

Except as discussed above, there have been no other changes in our internal control over financial reporting during the second quarter of 2019 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 13 to our Condensed Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A. of our 2018 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

The Omnibus Agreement, entered into as part of the Simplification Transactions, which closed on November 15, 2016, provides for the mechanics by which (i) the total number of PAGP's outstanding Class A shares will equal the number of AAP units held by PAGP, and (ii) the total number of our common units held by AAP will equal the sum of the number of outstanding Class A units of AAP ("AAP units") and the number of AAP units that are issuable to the holders of vested and earned Class B units of AAP ("AAP Management Units"). As such, we are obligated to issue common units to AAP upon any AAP Management Units becoming earned that were not earned as of the date of the closing of the Simplification Transactions. During the three months ended June 30, 2019, we issued 35,350 common units to AAP associated with AAP Management Units that became earned effective March 31, 2019. This issuance was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Item 5. OTHER INFORMATION

None.

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	—	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).
3.8	—	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).
3.9	—	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).
3.10	—	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).
3.11	—	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).
3.12	—	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).
3.13	—	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).
3.14	—	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).
3.15	—	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).
3.16	—	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).

3.17	—	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).
3.18	—	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).
3.19	—	Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC dated as of February 16, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed February 21, 2017).
3.20	—	Amendment No. 1 dated October 1, 2018 to the Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed August 20, 2018).
3.21	—	Amendment No. 2 dated December 10, 2018 to the Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed December 11, 2018).
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	—	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 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 4.1 to our Current Report on Form 8-K filed September 4, 2009).
4.5	—	Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 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 4.1 to our Current Report on Form 8-K filed January 11, 2011).
4.6	—	Twentieth Supplemental Indenture (3.65% Senior Notes due 2022) 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 4.1 to our Current Report on Form 8-K filed March 26, 2012).
4.7	—	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).
4.8	—	Twenty-Second Supplemental Indenture (2.85% Senior Notes due 2023) 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 4.1 to our Current Report on Form 8-K filed December 12, 2012).
4.9	—	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).
4.10	—	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).
4.11	—	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).

4.12	—	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).
4.13	—	Twenty-Seventh Supplemental Indenture (2.60% Senior Notes due 2019) 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 4.1 to our Current Report on Form 8-K filed December 11, 2014).
4.14	—	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).
4.15	—	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).
4.16	—	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).
4.17	—	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).
4.18	—	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).
4.19	—	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).
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

† 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, 2019

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

August 8, 2019

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

August 8, 2019

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, 2019

/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, 2019

/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, 2019 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, 2019

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, 2019 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, 2019