PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
August 09, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2018

OR

o 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)

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. ý Yes o No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). ý Yes o No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ý	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting company)   Emerging growth company o
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. o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes ý No
As of July 31, 2018, there were 725,582,739 Common Units outstanding.

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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, 2018	December 31, 2017
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$34	$37
Trade accounts receivable and other receivables, net	2,824	3,029
Inventory	636	713
Other current assets	358	221
Total current assets	3,852	4,000
PROPERTY AND EQUIPMENT	17,176	16,862
Accumulated depreciation	(2,919)	(2,773)
Property and equipment, net	14,257	14,089
OTHER ASSETS		
Goodwill	2,535	2,566
Investments in unconsolidated entities	3,116	2,756
Linefill and base gas	866	872
Long-term inventory	169	164
Other long-term assets, net	904	904
Total assets	$25,699	$25,351
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$3,555	$3,457
Short-term debt	943	737
Other current liabilities	624	337
Total current liabilities	5,122	4,531
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discounts and debt issuance costs	8,937	8,933
Other long-term debt	29	250
Other long-term liabilities and deferred credits	787	679
Total long-term liabilities	9,753	9,862
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
PARTNERS' CAPITAL		
Series A preferred unitholders (71,090,468 and 69,696,542 units outstanding, respectively)	1,505	1,505
Series B preferred unitholders (800,000 and 800,000 units outstanding, respectively)	787	788

Common unitholders (725,582,739 and 725,189,138 units outstanding, respectively)	8,532	8,665
Total partners' capital	10,824	10,958
Total liabilities and partners' capital	$25,699	$25,351

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 OPERATIONS
(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$7,781	$5,781	$15,892	$12,176
Transportation segment revenues	152	161	298	299
Facilities segment revenues	147	136	288	270
Total revenues	8,080	6,078	16,478	12,745
COSTS AND EXPENSES				
Purchases and related costs	7,551	5,320	15,070	10,912
Field operating costs	312	304	605	593
General and administrative expenses	80	68	159	142
Depreciation and amortization	49	129	175	250
Total costs and expenses	7,992	5,821	16,009	11,897
OPERATING INCOME	88	257	469	848
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	96	68	171	121
Interest expense (net of capitalized interest of $7, $9, $13 and $15, respectively)	(111)	(127)	(217)	(256)
Other income/(expense), net	11	1	10	(4)
INCOME BEFORE TAX	84	199	433	709
Current income tax expense	(7)	(1)	(20)	(11)
Deferred income tax benefit/(expense)	23	(9)	(25)	(65)
NET INCOME	100	189	388	633
Net income attributable to noncontrolling interests	—	(1)	—	(1)
NET INCOME ATTRIBUTABLE TO PAA	$100	$188	$388	$632
NET INCOME PER COMMON UNIT (NOTE 4):				
Net income allocated to common unitholders — Basic	$50	$148	$286	$555
Basic weighted average common units outstanding	725	725	725	708
Basic net income per common unit	$0.07	$0.21	$0.39	$0.78
Net income allocated to common unitholders — Diluted	$50	$148	$286	$555
Diluted weighted average common units outstanding	727	727	727	710
Diluted net income per common unit	$0.07	$0.21	$0.39	$0.78

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 COMPREHENSIVE INCOME
(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(unaudited)		(unaudited)	
Net income	$100	$189	$388	$633
Other comprehensive income/(loss)	(56)	75	(121)	111
Comprehensive income	44	264	267	744
Comprehensive income attributable to noncontrolling interests	—	(1)	—	(1)
Comprehensive income attributable to PAA	$44	$263	$267	$743

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, 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)

	Derivative Instruments	Translation Adjustments	Other	Total
	(unaudited)			
Balance at December 31, 2016	$(228)	$ (782)	$ 1	$(1,009)
Reclassification adjustments	9	—	—	9
Unrealized loss on hedges	(12)	—	—	(12)
Currency translation adjustments	—	114	—	114
Total period activity	(3)	114	—	111
Balance at June 30, 2017	$(231)	$ (668)	$ 1	$(898)

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

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

	Six Months Ended June 30,	
	2018	2017
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$388	$633
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	175	250
Equity-indexed compensation expense	36	22
Inventory valuation adjustments	—	35
Deferred income tax expense	25	65
Settlement of terminated interest rate hedging instruments	14	(29)
Equity earnings in unconsolidated entities	(171)	(121)
Distributions on earnings from unconsolidated entities	206	136
Other	13	5
Changes in assets and liabilities, net of acquisitions	329	465
Net cash provided by operating activities	1,015	1,461
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	—	(1,281)
Investments in unconsolidated entities	(216)	(250)
Additions to property, equipment and other	(724)	(549)
Proceeds from sales of assets	426	389
Return of investment from unconsolidated entities	9	21
Other investing activities	(1)	16
Net cash used in investing activities	(506)	(1,654)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings under commercial paper program (Note 9)	135	25
Net borrowings under senior unsecured revolving credit facility (Note 9)	126	—
Net repayments under senior secured hedged inventory facility (Note 9)	(333)	(450)
Repayments of senior notes	—	(400)
Net proceeds from sales of common units	—	1,664
Distributions paid to Series A preferred unitholders (Note 10)	(37)	—
Distributions paid to Series B preferred unitholders (Note 10)	(25)	—
Distributions paid to common unitholders (Note 10)	(435)	(770)
Other financing activities	60	123
Net cash provided by/(used in) financing activities	(509)	192
Effect of translation adjustment on cash	(3)	1
Net decrease in cash and cash equivalents	(3)	—
Cash and cash equivalents, beginning of period	37	47
Cash and cash equivalents, end of period	$34	$47

Cash paid for:		
Interest, net of amounts capitalized	$203	$252
Income taxes, net of amounts refunded	$11	$34

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 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 (Note 2)	—	—	113	113
Balance at January 1, 2018	1,505	788	8,778	11,071
Net income	74	25	289	388
Distributions (Note 10)	(74)	(25)	(435)	(534)
Other comprehensive loss	—	—	(121)	(121)
Other	—	(1)	21	20
Balance at June 30, 2018	$1,505	$787	$ 8,532	$10,824

	Limited Partners Series A Preferred Unitholders	Common Unitholders	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	(unaudited)				
Balance at December 31, 2016	$1,508	$ 7,251	$ 8,759	$ 57	$8,816
Net income	—	632	632	1	633
Distributions	—	(770)	(770)	(1)	(771)
Sales of common units	—	1,664	1,664	—	1,664
Acquisition of interest in Advantage Joint Venture	—	40	40	—	40
Other comprehensive income	—	111	111	—	111
Other	(1)	9	8	—	8
Balance at June 30, 2017	$1,507	$ 8,937	$ 10,444	$ 57	$10,501

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
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

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, 2018, AAP also owned a limited partner interest in us through its ownership of approximately 281.2 million of our common units (approximately 35% 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, 2018, owned an approximate 56% 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.

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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
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 2017 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. The condensed consolidated balance sheet data as of December 31, 2017 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, 2018 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.

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Note 2—Recent Accounting Pronouncements

Except as discussed below and in our 2017 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, 2018 that are of significance or potential significance to us.

Accounting Standards Updates Adopted During the Period

In February 2017, the FASB issued ASU 2017-05, Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets. The ASU clarifies what type of transactions involving nonfinancial assets are covered by the scope of the standard and provides guidance on how to account for those transactions, including partial sales of real estate. Within this guidance, all sales and partial sales of businesses, which may have previously been accounted for using the in-substance real estate guidance, should follow the consolidation guidance. This guidance is effective for interim and annual periods beginning after December 15, 2017, and must be adopted at the same time as Topic 606 (defined below). We adopted this ASU on January 1, 2018, using the modified retrospective approach. The cumulative effect of our adoption resulted in increases in both the carrying value of investments in unconsolidated entities and retained earnings of $113 million related to the retained noncontrolling interest in those entities from partial sales of businesses accounted for under in-substance real estate guidance during 2016 and 2017.

In November 2016, the FASB issued ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force), requiring that a statement of cash flows explain the change in total cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents during the period. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual periods beginning after December 15, 2017. We adopted this ASU on January 1, 2018. Our adoption did not have an impact on our statement of cash flows.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, followed by a series of related accounting standard updates (collectively referred to as “Topic 606”) with the underlying principle that an entity will recognize revenue to reflect amounts expected to be received in exchange for the provision of goods and services to customers upon the transfer of control of those goods or services. We adopted Topic 606 on January 1, 2018, and applied the modified retrospective approach. See Note 3 for additional information.

Accounting Standards Updates Issued During the Period

In June 2018, the FASB issued ASU 2018-07, Compensation—Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting, which expands the scope of Topic 718 to include share-based payment awards to nonemployees and eliminates the classification differences for employee and nonemployee share-based payment awards. This guidance is effective for interim and annual periods beginning after December 15, 2018, with early adoption permitted. We expect to adopt this guidance on January 1, 2019, and we do not currently anticipate that our adoption will have a material impact on our financial position, results of operations or cash flows.

Other Accounting Standards Updates

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), that revises the current 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 lease assets and 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 will become effective for interim and annual periods beginning after December 15, 2018, with a modified retrospective application required. Early adoption is permitted, including adoption in an interim period. We expect to adopt this guidance on January 1, 2019 and are assessing the use of optional practical expedients. We are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations and cash flows. Although our evaluation is ongoing, we do expect that the adoption will impact our financial statements as the standard requires the recognition on the balance sheet of a right of use asset and corresponding lease liability. We are currently analyzing our contracts to determine whether they contain a lease under the revised guidance and have not quantified the amount of the asset and liability that will be recognized on our consolidated balance sheet.

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Note 3—Revenues

Revenue Recognition

On January 1, 2018, we adopted Topic 606 using the modified retrospective method applied to those contracts which were not completed as of January 1, 2018. Results for reporting periods beginning after January 1, 2018 are presented under Topic 606, while prior period amounts are not adjusted and continue to be reported in accordance with our historic accounting under ASC Topic 605, Revenue Recognition.

There was no material impact to opening retained earnings as of January 1, 2018 due to the adoption of Topic 606. There also was no material impact to revenues, or any other financial statement line items, for the three and six months ended June 30, 2018 as a result of applying Topic 606.

Under Topic 606, we disaggregate our revenues by segment and type of activity. These categories depict how the nature, amount, timing and uncertainty of revenues and cash flows are affected by economic factors.

Supply and Logistics Segment Revenues from Contracts with Customers. The following table presents our Supply and Logistics segment revenues from contracts with customers disaggregated by type of activity (in millions):

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

Revenues from sales of crude oil, NGL and natural gas are recognized at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee. Sales of crude oil and NGL consist of outright sales contracts. The consideration received under these contracts is variable based on commodity prices. Inventory purchases and sales under buy/sell transactions are treated as inventory exchanges which are excluded from Supply and Logistics segment revenues in our Condensed Consolidated Statements of Operations. Revenues recognized by our Supply and Logistics segment primarily represent margin based activities.

In addition, we have certain crude oil sales agreements that are entered into in conjunction with storage arrangements and future inventory exchanges. The revenues under these agreements are deferred until all performance obligations associated with the related agreements are completed. The inventory that has been sold under these crude oil sales agreements is reflected in “Other Current Assets” on our Condensed Consolidated Balance Sheet until all of our performance obligations are complete. At that time, the inventory that has been sold is removed from our Condensed Consolidated Balance Sheet and recorded as “Purchases and Related Costs” in our Condensed Consolidated Statement of Operations. At June 30, 2018, other current assets and deferred revenue associated with these agreements was approximately $197 million and $197 million, respectively. See Contract Balances below for further discussion of contract liabilities associated with these agreements.

We may also utilize derivatives in connection with the transactions described above. Derivative revenue is not included as a component of revenue from contracts with customers, but is included in other items in revenue. The change in the fair value of derivatives that are not designated or do not qualify for hedge accounting is recognized in revenues each period.

Transportation Segment Revenues from Contracts with Customers. The following table presents our Transportation segment revenues from contracts with customers disaggregated by type of activity (in millions):

	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
Transportation segment revenues from contracts with customers		
Tariff activities:		
Crude oil pipelines	$ 412	$ 801
NGL pipelines	24	51
Total tariff activities	436	852
Trucking	34	68
Total Transportation segment revenues from contracts with customers	$ 470	$ 920

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems and trucks. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil and NGL at a published tariff. We primarily recognize pipeline tariff and fee revenues over time as services are rendered, based on the volumes transported. As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor. We recognize the allowance volumes collected as part of the transaction price and record this non-cash consideration at fair value, measured as of the contract inception date.

Facilities Segment Revenues from Contracts with Customers. The following table presents our Facilities segment revenues from contracts with customers disaggregated by type of activity (in millions):

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

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. Revenues generated in this segment include (i) fees that are generated from storage capacity agreements, (ii) terminal throughput fees that are generated when we receive liquids from one connecting source and deliver the applicable product to another connecting carrier, (iii) fees from NGL fractionation and isomerization services, (iv) fees from natural gas and condensate processing services, (v) fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services (“natural gas storage related activities”) and (vi) loading and unloading fees at our rail terminals.

We generate revenue through a combination of month-to-month and multi-year agreements and processing arrangements. Storage fees are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized as our performance obligation is to make available storage capacity for a period of time. Terminal fees (including throughput and rail fees) are recognized as the liquids enter or exit the terminal and are received from or delivered to the connecting carrier or third-party terminal, as applicable. Fees from NGL fractionation and isomerization services and gas processing services are recognized in the period when the services are performed. Natural gas storage related activities fees are recognized in the period the natural gas moves across our header system. We recognize rail loading and unloading fees when the volumes are delivered or received.

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Reconciliation to Total Revenues of Reportable Segments. Topic 606 requires us to provide information about the relationship between the disaggregated revenues presented above and segment revenues. These disclosures only include information regarding revenues associated with consolidated entities, and revenues from entities accounted for by the equity method are not included in the disclosures. The following table presents the reconciliation of our revenues from contracts with customers (as described above for each segment) to segment revenues and total revenues as disclosed in our Condensed Consolidated Statement of Operations (in millions):

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

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

Trade Accounts Receivable and Other Receivables. We generally invoice customers in the month following that in which products or services were provided and generally require payment within 30 days of the invoice date. 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 Sheet (in millions):

	June 30, 2018	December 31, 2017
Trade accounts receivable arising from revenues from contracts with customers	$ 2,721	$ 2,584
Other trade accounts receivables and other receivables [(1)]	3,763	3,709
Impact due to contractual rights of offset with counterparties	(3,660)	(3,264)
Trade accounts receivable and other receivables, net	$ 2,824	$ 3,029

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

Minimum Volume Commitments. We have certain agreements that require counterparties to transport or throughput a minimum volume over an agreed upon period. These contracts are within the scope of Topic 606. In addition, we have certain buy/sell agreements that require customers to deliver a minimum volume over an agreed upon period that are within the scope of ASC Topic 845, Nonmonetary Transactions (“Topic 845”). 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 as a contract liability 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.

At June 30, 2018 and December 31, 2017, counterparty deficiencies associated with agreements (under Topic 606 and Topic 845) that include minimum volume commitments totaled $62 million and $57 million, respectively, of which $44 million and $37 million, respectively, was recorded as a contract liability, which we refer to as deferred revenue. The remaining balance of $18 million and $20 million at June 30, 2018 and December 31, 2017, respectively, was related to deficiencies for which the

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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, 2018 (in millions):

	Contract Liabilities
Balance at December 31, 2017	$ 90
Amounts recognized as revenue	(79)
Additions [(1)] [(2)]	445
Other	(3)
Balance at June 30, 2018	$ 453

(1) Includes approximately $197 million associated with crude oil sales agreements that are entered into in conjunction with storage arrangements and future inventory exchanges. Such amount is expected to be recognized as revenue in the second half of 2018.

(2) Includes $100 million associated with long-term capacity agreements with Cactus II Pipeline LLC. See Note 12 for additional information.

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, 2018 (in millions):

	Remainder of 2018	2019	2020	2021	2022	2023 and Thereafter
Pipeline revenues supported by minimum volume commitments and long-term capacity agreements [(1)]	$ 51	$150	$193	$181	$180	$ 799
Long-term storage, terminalling and throughput agreements revenues	225	354	274	207	158	554
Total	$ 276	$504	$467	$388	$338	$ 1,353

(1) Includes revenues from certain contracts for which the amount and timing of revenue is subject to the completion of underlying construction projects.

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:

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Minimum volume commitments related to the assets of equity method investees — Contracts include those related to the Eagle Ford, BridgeTex, STACK, Caddo, Saddlehorn, White Cliffs, Cheyenne and Diamond pipeline systems;

- Acreage dedications — Contracts include those related to the Permian Basin, Eagle Ford, Central, Rocky Mountain and Canada regions;

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- Supply and Logistics contracts within the scope of Topic 845 — Contracts include buy/sell arrangements 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, as discussed below;
- Transportation and Facilities contracts that are short-term, as discussed below;
- Contracts within the scope of ASC Topic 840, Leases; and
- Contracts within the scope of ASC Topic 815, Derivatives and Hedging.

We have elected practical expedients to exclude the presentation of remaining performance obligations for variable consideration which relates to wholly unsatisfied performance obligations. Certain contracts do not meet the requirements for presentation of remaining performance obligations under Topic 606 due to variability in amount of performance obligation remaining, variability in the timing of recognition or variability in consideration. Acreage dedications do require us to perform future services but do not contain a minimum level of services and are therefore excluded from this presentation. Long-term supply and logistics arrangements contain variable timing, volumes and/or consideration and are excluded from this presentation. The duration of these contracts varies across the periods presented above.

Additionally, we have elected practical expedients to exclude contracts with terms of one year or less, and therefore exclude the presentation of remaining performance obligations for short-term transportation, storage and processing services, supply and logistics arrangements, including the non-cancelable period of evergreen arrangements, and any other types of arrangements with terms of one year or less.

Note 4—Net Income Per Common Unit

We calculate basic and diluted net income per common unit by dividing net income (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 (which include LTIP awards and AAP Management Units). 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 and 2017 as the effect was antidilutive. Our LTIP awards that contemplate the issuance of common units and certain AAP Management Units that contemplate the issuance of common units to AAP when such AAP Management Units become earned are considered dilutive unless (i) they become vested or earned only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards and AAP Management Units that were deemed to be dilutive during the three and six months ended June 30, 2018 and 2017 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 16 to our Consolidated Financial Statements included in Part IV of our 2017 Annual Report on Form 10-K for a complete discussion of our LTIP awards and the AAP Management Units.

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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,	
	2018	2017	2018	2017
Basic Net Income per Common Unit				
Net income attributable to PAA	$100	$188	388	632
Distributions to Series A preferred unitholders	(37)	(35)	(74)	(69)
Distributions to Series B preferred unitholders	(12)	—	(25)	—
Distributions to participating securities	(1)	(1)	(2)	(1)
Other	—	(4)	(1)	(7)
Net income allocated to common unitholders [1]	$50	$148	$286	$555
Basic weighted average common units outstanding	725	725	725	708
Basic net income per common unit	$0.07	$0.21	$0.39	$0.78
Diluted Net Income per Common Unit				
Net income attributable to PAA	$100	$188	$388	$632
Distributions to Series A preferred unitholders	(37)	(35)	(74)	(69)
Distributions to Series B preferred unitholders	(12)	—	(25)	—
Distributions to participating securities	(1)	(1)	(2)	(1)
Other	—	(4)	(1)	(7)
Net income allocated to common unitholders [1]	$50	$148	$286	$555
Basic weighted average common units outstanding	725	725	725	708
Effect of dilutive securities:				
Equity-indexed compensation plan awards	2	2	2	2
Diluted weighted average common units outstanding	727	727	727	710
Diluted net income per common unit	$0.07	$0.21	$0.39	$0.78

(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—Accounts Receivable, Net

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL and natural gas. 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. As of June 30, 2018 and December 31, 2017, we had received $164 million and $117 million, respectively, of advance cash payments from third parties to mitigate credit risk. We also received $42 million and $54 million as of June 30, 2018 and

December 31, 2017, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. Additionally, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. Furthermore, 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) for the majority of our net-cash arrangements.

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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, 2018 and December 31, 2017, 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, 2018 and December 31, 2017. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Note 6—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, 2018				December 31, 2017			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit [(1)]	Volumes	Unit of Measure	Carrying Value	Price/ Unit [(1)]
Inventory								
Crude oil	5,188	barrels	$ 359	$ 69.20	7,800	barrels	$ 402	$ 51.54
NGL	10,583	barrels	262	$ 24.76	10,774	barrels	294	$ 27.29
Other	N/A		15	N/A	N/A		17	N/A
Inventory subtotal			636				713	
Linefill and base gas								
Crude oil	12,410	barrels	716	$ 57.70	12,340	barrels	719	$ 58.27
NGL	1,562	barrels	42	$ 26.89	1,597	barrels	45	$ 28.18
Natural gas	24,976	Mcf	108	$ 4.32	24,976	Mcf	108	$ 4.32
Linefill and base gas subtotal			866				872	
Long-term inventory								
Crude oil	1,903	barrels	113	$ 59.38	1,870	barrels	105	$ 56.15
NGL	2,352	barrels	56	$ 23.81	2,167	barrels	59	$ 27.23
Long-term inventory subtotal			169				164	
Total			$ 1,671				$ 1,749	

(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.

At the end of each reporting period, we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. Any resulting adjustments are a component of “Purchases and related costs” on our accompanying Condensed Consolidated Statements of Operations. We recorded a charge of $35 million during the three and six months ended June 30, 2017 primarily related to the writedown of our crude oil inventory due to a decline in prices. Substantially all of this inventory valuation adjustment was offset by the recognition of gains on derivative instruments being utilized to hedge future sales of our crude oil inventory. Such gains were recorded to “Supply and Logistics segment revenues” on our accompanying Condensed Consolidated Statements of Operations. See Note 11 for discussion of our derivative and risk management activities. We did not record such charges during 2018.

Note 7—Divestitures

During the six months ended June 30, 2018, we received proceeds from asset sales of $426 million. The assets sold primarily included non-core property and equipment or are associated with the formation of strategic joint ventures and were previously reported in our Facilities and Transportation segments. We recognized a net gain related to these asset sales of approximately $81 million during the three and six months ended June 30, 2018, which is included in "Depreciation and amortization" on our Condensed Consolidated Statements of Operations. Such amount is comprised of gains of $105 million and losses of $24 million.

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Note 8—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, 2017	$ 1,070	$ 988	$ 508	$2,566
Foreign currency translation adjustments	(11)	(5)	(3)	(19)
Dispositions and reclassifications to assets held for sale	(9)	(3)	—	(12)
Balance at June 30, 2018	$ 1,050	$ 980	$ 505	$2,535

We completed our goodwill impairment test as of June 30, 2018 and determined that there was no impairment of goodwill.

Note 9—Debt

Debt consisted of the following (in millions):

	June 30, 2018	December 31, 2017
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 3.1% and 2.4%, respectively [(1)]	$ 259	$ —
Senior secured hedged inventory facility, bearing a weighted-average interest rate of 3.1% and 2.6%, respectively [(1)]	450	664
Senior unsecured revolving credit facility, bearing a weighted-average interest rate of 3.4% [(1)]	100	—
Other	134	73
Total short-term debt [(2)]	943	737
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $63 and $67, respectively	8,937	8,933
Commercial paper notes and senior secured hedged inventory facility borrowings [(3)]	—	247
Senior unsecured revolving credit facility, bearing a weighted-average interest rate of 3.4% [(3)]	26	—
Other	3	3
Total long-term debt	8,966	9,183
Total debt [(4)]	$ 9,909	$ 9,920

(1) We classified these commercial paper notes and credit facility borrowings as short-term as of June 30, 2018 and December 31, 2017, 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, 2018 and December 31, 2017, balance includes borrowings of $426 million and $212 million, respectively, for cash margin deposits with NYMEX and ICE, which are associated with financial derivatives used for hedging purposes.

(3) As of June 30, 2018 and December 31, 2017, we classified a portion of our commercial paper notes and credit facility borrowings as long-term based on our ability and intent to refinance such amounts on a long-term basis.

(4) Our fixed-rate senior notes had a face value of approximately $9.0 billion at both June 30, 2018 and December 31, 2017. We estimated the aggregate fair value of these notes as of June 30, 2018 and December 31, 2017 to be approximately $8.7 billion and $9.1 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 and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities and commercial paper program are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

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Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the six months ended June 30, 2018 and 2017 were approximately $23.5 billion and $36.8 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $23.6 billion and $37.2 billion for the six months ended June 30, 2018 and 2017, 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, 2018 and December 31, 2017, we had outstanding letters of credit of $168 million and $166 million, respectively.

Note 10—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, 2017	69,696,542	800,000	725,189,138
Issuance of Series A preferred units in connection with in-kind distribution	1,393,926	—	—
Other	—	—	393,601
Outstanding at June 30, 2018	71,090,468	800,000	725,582,739

	Limited Partners	
	Series A Preferred Units	Common Units
Outstanding at December 31, 2016	64,388,853	669,194,419
Issuances of Series A preferred units in connection with in-kind distributions	2,601,300	—
Sales of common units	—	54,119,893
Issuance of common units in connection with acquisition of interest in Advantage Joint Venture	—	1,252,269
Other	—	130,154
Outstanding at June 30, 2017	66,990,153	724,696,735

Distributions

Series A Preferred Unit Distributions. The following table details distributions paid to our Series A preferred unitholders during or pertaining to the first six months of 2018 (in millions, except unit and per unit data):

Series A Preferred Unitholders

Distribution Payment Date	Distribution [2] Cash	Units	Distribution per Unit
August 14, 2018 [1]	$37	—	$ 0.525
May 15, 2018	$37	—	$ 0.525
February 14, 2018	$—	1,393,926	$ 0.525

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(1) Payable to unitholders of record at the close of business on July 31, 2018 for the period from April 1, 2018 through June 30, 2018. At June 30, 2018, such amount was accrued to distributions payable in "Accounts payable and accrued liabilities" on our Condensed Consolidated Balance Sheet.

(2) On February 14, 2018, we issued additional Series A preferred units in lieu of a cash distribution of $37 million. With respect to any quarter ending on or prior to December 31, 2017 (the "Initial Distribution Period"), we were able to elect to pay distributions on our Series A preferred units in additional Series A preferred units, in cash or a combination of both. The Initial Distribution Period ended with the February 2018 distribution; as such, with respect to any quarter ending after the Initial Distribution Period, we must pay distributions on our Series A preferred units in cash.

Series B Preferred Unit Distributions. Distributions on our Series B preferred units are payable semiannually 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 2018 (in millions, except per unit data):

Distribution Payment Date	Series B Preferred Unitholders Cash Distribution	Distribution per Unit
May 15, 2018	$24.5	$ 30.625

As of June 30, 2018, we had accrued approximately $6 million of distributions payable to our Series B preferred unitholders in "Accounts payable and accrued liabilities" on our Condensed Consolidated Balance Sheet.

Common Unit Distributions. The following table details distributions paid during or pertaining to the first six months of 2018 (in millions, except per unit data):

	Distributions			
	Common Unitholders			Cash Distribution per Common Unit
Distribution Payment Date	Public	AAP	Total Cash Distribution	
August 14, 2018 (1)	$133	$ 85	$ 218	$ 0.30
May 15, 2018	$133	$ 85	$ 218	$ 0.30
February 14, 2018	$133	$ 85	$ 218	$ 0.30

(1) Payable to unitholders of record at the close of business on July 31, 2018 for the period from April 1, 2018 through June 30, 2018.

Note 11—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. Both at the inception of the hedge and throughout the hedging relationship, we assess whether the derivatives employed are highly effective in offsetting changes in cash flows of anticipated hedged transactions.

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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 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, 2018, net derivative positions related to these activities included:

- A net long position of 4.0 million barrels associated with our crude oil purchases, which was unwound ratably during July 2018 to match monthly average pricing.
- A net short time spread position of 8.8 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through December 2019.
- A crude oil grade basis position of 55.4 million barrels through December 2020. These derivatives allow us to lock in grade basis differentials.
- A net short position of 11.0 million barrels through December 2020 related to anticipated net sales of our crude oil and NGL inventory.

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, 2018, our PLA hedges included a short position consisting of crude oil futures of 1.0 million barrels through June 2019 and a long call option position of 1.0 million barrels through December 2019.

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. As of June 30, 2018, we had a long natural gas position of 62.1 Bcf which hedges a portion of our natural gas processing and operational needs through December 2020. We also had a short propane position of 12.9 million barrels through December 2020, a short butane position of 3.9 million barrels through December 2020 and a short WTI position of 2.4 million barrels through December 2020. In addition, we had a long power position of 0.2 million megawatt hours, which hedges a portion of our power supply requirements at our Canadian natural gas processing and fractionation plants through December 2019.

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, 2018 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/14/2019	2.83 %	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/15/2020	3.06 %	Cash flow hedge

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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.

As of June 30, 2018, our outstanding 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, 2018 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2018	$141	$187	$1.00 - $1.33
Forward exchange contracts that exchange USD for CAD:				
	2018	$266	$343	$1.00 - $1.29
	2019	$59	$76	$1.00 - $1.29

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 11 to our Consolidated Financial Statements included in Part IV of our 2017 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 that qualify as cash flow hedges, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions are recognized in earnings. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items 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.

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

Location of Gain/(Loss)	Three Months Ended June 30, 2018 Derivatives in Hedging Relationships	Three Months Ended June 30, 2018 Derivatives Not Designated as a Hedge	Three Months Ended June 30, 2018 Total	Three Months Ended June 30, 2017 Derivatives in Hedging Relationships	Three Months Ended June 30, 2017 Derivatives Not Designated as a Hedge	Three Months Ended June 30, 2017 Total
Commodity Derivatives						
Supply and Logistics segment revenues	$—	$ (339)	$(339)	$—	$ 99	$99
Field operating costs	—	—	—	—	(1)	(1)
Depreciation and amortization	—	—	—	(3)	—	(3)
Interest Rate Derivatives						
Interest expense, net	(2)	—	(2)	(4)	—	(4)
Foreign Currency Derivatives						
Supply and Logistics segment revenues	—	(6)	(6)	—	—	—
Preferred Distribution Rate Reset Option						
Other income/(expense), net	—	8	8	—	2	2
Total Gain/(Loss) on Derivatives Recognized in Net Income	$(2)	$ (337)	$(339)	$(7)	$ 100	$93

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Location of Gain/(Loss)	Six Months Ended June 30, 2018 Derivatives in Hedging Relationships	Derivatives Not Designated as a Hedge	Total	Six Months Ended June 30, 2017 Derivatives in Hedging Relationships	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives						
Supply and Logistics segment revenues	$—	$ (384)	$(384)	$—	$ 195	$195
Field operating costs	—	1	1	—	(4)	(4)
Depreciation and amortization	—	—	—	(3)	—	(3)
Interest Rate Derivatives						
Interest expense, net	(1)	—	(1)	(6)	—	(6)
Foreign Currency Derivatives						
Supply and Logistics segment revenues	—	(12)	(12)	—	2	2
Preferred Distribution Rate Reset Option						
Other income/(expense), net	—	5	5	—	(2)	(2)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$(1)	$ (390)	$(391)	$(9)	$ 191	$182

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The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of June 30, 2018 (in millions):

	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Interest rate derivatives	Other current assets	$ 5	Other long-term liabilities and deferred credits	$ (5)
Total derivatives designated as hedging instruments		$ 5		$ (5)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 133	Other current assets	$ (487)
	Other long-term assets, net	10	Other current liabilities	(128)
	Other current liabilities	25	Other long-term liabilities and deferred credits	(27)
	Other long-term liabilities and deferred credits	13		
Foreign currency derivatives	Other current liabilities	1	Other current liabilities	(8)
Preferred Distribution Rate Reset Option			Other long-term liabilities and deferred credits	(17)
Total derivatives not designated as hedging instruments		$ 182		$ (667)
Total derivatives		$ 187		$ (672)

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The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of December 31, 2017 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Interest rate derivatives	Other current liabilities	$ 2	Other current liabilities	$ (27)
			Other long-term liabilities and deferred credits	(11)
Total derivatives designated as hedging instruments		$ 2		$ (38)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 73	Other current assets	$ (227)
	Other long-term assets, net	1	Other current liabilities	(131)
	Other current liabilities	5	Other long-term liabilities and deferred credits	(5)
	Other long-term liabilities and deferred credits	3		
Foreign currency derivatives	Other current assets	6	Other current assets	(2)
Preferred Distribution Rate Reset Option			Other long-term liabilities and deferred credits	(22)
Total derivatives not designated as hedging instruments		$ 88		$ (387)
Total derivatives		$ 90		$ (425)

Our derivative transactions (other than the Preferred Distribution Rate Reset Option) 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:

	June 30, 2018	December 31, 2017
Initial margin	$ 146	$ 48
Variation margin posted	357	164
Letter of credit	(77)	—

Net broker receivable	$ 426	$ 212

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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, 2018		December 31, 2017	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 187	$ (672)	$ 90	$ (425)
Netting adjustment	(526)	526	(239)	239
Cash collateral paid	426	—	212	—
Net position - asset/(liability)	$ 87	$ (146)	$ 63	$ (186)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 77	$ —	$ 62	$ —
Other long-term assets, net	10	—	1	—
Other current liabilities	—	(110)	—	(151)
Other long-term liabilities and deferred credits	—	(36)	—	(35)
	$ 87	$ (146)	$ 63	$ (186)

As of June 30, 2018, there was a net loss of $173 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, 2018, 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, 2018; 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,	
	2018	2017	2018	2017
Interest rate derivatives, net	$ 13	$ (19)	$ 45	$ (12)

At June 30, 2018 and December 31, 2017, 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, 2018				Fair Value as of December 31, 2017			
Recurring Fair Value Measures [1]	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total

Commodity derivatives	$(252)	$(208)	$(1)	$(461)	$5	$(278)	$(8)	$(281)
Interest rate derivatives	—	—	—	—	—	(36)	—	(36)
Foreign currency derivatives	—	(7)	—	(7)	—	4	—	4
Preferred Distribution Rate Reset Option	—	—	(17)	(17)	—	—	(22)	(22)
Total net derivative asset/(liability)	$(252)	$(215)	$(18)	$(485)	$5	$(310)	$(30)	$(335)

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

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Level 1

Level 1 of the fair value hierarchy includes exchange-traded commodity derivatives and over-the-counter commodity contracts such as futures and options. The fair value of exchange-traded commodity derivatives and over-the-counter commodity contracts are 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 active markets. In addition, it includes certain physical commodity contracts. The fair value of these derivatives is based on broker price quotations which are corroborated with market observable inputs.

Level 3

Level 3 of the fair value hierarchy includes certain physical commodity contracts, over-the-counter financial commodity contracts, and the Preferred Distribution Rate Reset Option contained in our partnership agreement which is classified as an embedded derivative.

The fair value of our Level 3 physical commodity contracts and over-the-counter financial commodity contracts are based on valuation models utilizing significant unobservable pricing inputs and timing estimates, which involve management judgment. Significant deviations from these inputs and estimates could result in a material change in fair value to our physical commodity contracts and over-the-counter financial commodity contracts. 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. Unrealized gains and losses associated with the over-the counter financial commodity contracts are reported in our Condensed Consolidated Statements of Operations as Field operating costs.

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 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,	
	2018	2017	2018	2017

Beginning Balance	$(26)	$(36)	$(30)	$(36)
Net gains/(losses) for the period included in earnings	7	3	5	(1)
Settlements	1	—	7	3
Derivatives entered into during the period	—	3	—	4
Ending Balance	$(18)	$(30)	$(18)	$(30)
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	$7	$6	$5	$3

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Note 12—Related Party Transactions

See Note 15 to our Consolidated Financial Statements included in Part IV of our 2017 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, 2018 and December 31, 2017, we owned 515,460,375 and 510,925,432, 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 Oxy

As of June 30, 2018, Oxy had a representative on the board of directors of PAGP GP and owned approximately 11% of the limited partner interests in AAP (which represents an approximate 4% indirect ownership interest in PAA). During the three and six months ended June 30, 2018 and 2017, we recognized sales and transportation revenues and purchased petroleum products from Oxy. 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 those transactions is included below (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues	$280	$220	$558	$453
Purchases and related costs [1]	$(91)	$(61)	$(162)	$(101)

[1] 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.

We currently have a netting arrangement with Oxy. Our gross receivable and payable amounts with Oxy were as follows (in millions):

	June 30, 2018	December 31, 2017
Trade accounts receivable and other receivables	$ 1,115	$ 1,075
Accounts payable	$ 1,012	$ 990

Transactions with Equity Method Investees

We also have transactions with companies in which we hold an investment accounted for under the equity method of accounting. We recorded revenues of $3 million and $1 million during the three months ended June 30, 2018 and 2017, respectively, and $5 million and $2 million during the six months ended June 30, 2018 and 2017, respectively, primarily related to transportation services. In addition, we utilized transportation services and purchased petroleum products provided by these companies. Costs related to these services and product purchases totaled $135 million and $108 million for the three months ended June 30, 2018 and 2017, respectively, and $265 million and $193 million for the six months ended June 30, 2018 and 2017, respectively. These costs include amounts associated with a joint tariff administered by an equity method investee, of which $71 million and $52 million for the three months ended June 30, 2018 and 2017, respectively, and $139 million and $93 million for the six months ended June 30, 2018 and 2017, respectively, were associated with a PAA wholly-owned pipeline. These transactions were conducted at posted tariff rates or contracted rates or prices that we believe approximate market.

Receivables from our equity method investees totaled $46 million and $26 million at June 30, 2018 and December 31, 2017, respectively, and primarily included amounts related to transportation services and amounts owed to us related to expansion projects where we serve as construction manager. Accounts payable to our equity method investees were $106 million and $41 million at June 30, 2018 and December 31, 2017, respectively, and primarily included amounts related to transportation services utilized and amounts advanced to us related to expansion projects where we serve as construction manager.

In addition, 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.

During the six months ended June 30, 2018, we made net investments in our equity method investees of $216 million (including amounts contributed to and received from Cactus II Pipeline LLC subsequent to its formation, as discussed further below). Such net investments are primarily related to funding our portion of the development, construction or capital expansion projects of such entities and are reflected in "Investments in unconsolidated entities" on our Condensed Consolidated Statement of Cash Flows.

Cactus II JV Formation. In the second quarter of 2018, a subsidiary of Oxy and another third party each exercised their purchase options for a 20% interest and a 15% interest, respectively, in Cactus II Pipeline LLC ("Cactus II"), which owns the Cactus II pipeline system that is currently under construction. Although we own a majority of Cactus II's equity, we do not have a controlling financial interest in Cactus II because the other members have substantive participating rights. Therefore, we account for our ownership interest in Cactus II as an equity method investment. Following the exercise of the purchase options, we deconsolidated Cactus II resulting in a reduction of property and equipment of $74 million (which was representative of the costs incurred to date to construct the pipeline and equivalent to fair value), and we received $26 million of cash from Cactus II, which represented the other members' portion of the property and equipment.

In addition, during the second quarter of 2018, we received a $100 million advance cash payment from Cactus II associated with pipeline capacity agreements, which is recorded as long-term deferred revenue within "Other long-term liabilities and deferred credits" on our Condensed Consolidated Balance Sheet. Such amount will be recognized in revenue ratably over the life of the contracts beginning once the Cactus II pipeline system has been placed into service.

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

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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, 2018, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident, as discussed further below) totaled $138 million, of which $53 million was classified as short-term and $85 million was classified as long-term. At December 31, 2017, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident) totaled $162 million, of which $72 million was classified as short-term and $90 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in “Accounts payable and accrued liabilities” and “Other long-term liabilities and deferred credits,” respectively, on our Condensed Consolidated Balance Sheets. At June 30, 2018, we had recorded receivables totaling $49 million for amounts probable of recovery under insurance and from third parties under indemnification agreements, of which $23 million was reflected in “Trade accounts receivable and other receivables, net” and $26 million was reflected in “Other long-term assets, net” on our Condensed Consolidated Balance Sheet. At December 31, 2017, we had recorded $55 million of such receivables, of which $29 million was reflected in “Trade accounts receivable and other receivables, net” and $26 million was reflected in “Other long-term assets, net” on our Condensed Consolidated Balance Sheet.

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:

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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 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. On July 28, 2016, at an arraignment hearing held in California Superior Court in Santa Barbara County, PAA pled not guilty to all counts. Since May of 2016, 31 of the criminal charges against PAA (including one felony charge) and all of the criminal charges against our employee, have been dismissed. Nine of the remaining 15 charges are misdemeanor charges relating to wildlife allegedly taken as a result of the accidental release. The remaining six counts relate to the release of crude oil or reporting of the release. PAA believes that the criminal charges (including the three felony charges) are unwarranted and that neither PAA nor any of its employees engaged in any criminal behavior at any time in connection with this accident. A jury trial regarding the remaining charges is currently taking place and PAA continues to vigorously defend itself against the charges.

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 are cooperating with the DOJ's investigation by responding to their requests for documents and access to our employees. The DOJ has already spoken to several of our employees and has expressed an interest in talking to other 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. While to date no civil actions or criminal charges with respect to the Line 901 release, other than those brought pursuant to the May 2016 Indictment, have been brought against PAA or any of its affiliates, officers or employees by PHMSA, DOJ, EPA, the California Attorney General, the Santa Barbara District Attorney or the California Department of Fish and Wildlife, and no fines or penalties have been imposed by such governmental agencies, 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, 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 are processing those claims for payment as we receive them. 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. The 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; (ii) individuals or businesses who were employed by or had contracts with certain designated oil platforms and related onshore processing facilities in the vicinity of the release as of the date of the release and (iii) beachfront property and easement owners whose properties were oiled. The Ninth Circuit Court of Appeals has granted our petition for leave to appeal the oil industry class certification. 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 have also been 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 have been consolidated into a single proceeding in the United States District Court for the Southern District of Texas. In general, these lawsuits allege 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 claim unspecified damages as a result of the reduction in value of their investments in the Partnership and PAGP, which they attribute 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 have filed notice of intent to file an appeal of the dismissal. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we have indemnified and funded the defense costs of our officers and directors in connection with this lawsuit; we have 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. In general, these derivative lawsuits allege that the various defendants breached their fiduciary duties, engaged in gross mismanagement and made false and misleading statements, among other similar allegations, in connection with their management and oversight of the Partnership during the period of time leading up to and following the Line 901 release. The plaintiffs in the remaining lawsuit claim that the Partnership suffered unspecified damages as a result of the actions of the various defendants and seek to hold the defendants liable for such damages, in addition to other remedies. The defendants deny the allegations in this lawsuit and have responded accordingly. 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 this lawsuit.

We have also received several other individual lawsuits and complaints from companies 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, 2018, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $335 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

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"Field operating costs" in our Condensed Consolidated Statement 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 and 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, 2018, we had a remaining undiscounted gross liability of $76 million related to this event, of which approximately $44 million is presented as a current liability in "Accounts payable and accrued 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, 2018, we had collected, subject to customary reservations, $180 million out of the approximate $220 million of release costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of June 30, 2018, we have recognized a receivable of approximately $40 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 $16 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 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 and gains or losses on significant asset sales of 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.

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

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

Three Months Ended June 30, 2017	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Revenues:					
External customers [1]	$ 258	$ 136	$ 5,781	$ (97)	$ 6,078
Intersegment [2]	167	153	2	97	419
Total revenues of reportable segments	$ 425	$ 289	$ 5,783	$ —	$ 6,497
Equity earnings in unconsolidated entities	$ 68	$ —	$ —		$ 68
Segment adjusted EBITDA	$ 298	$ 180	$ (28)		$ 450
Maintenance capital	$ 27	$ 39	$ 5		$ 71

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

Six Months Ended June 30, 2017	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Revenues:					
External customers [1]	$ 483	$ 270	$ 12,176	$ (184)	$ 12,745
Intersegment [2]	331	312	8	184	835
Total revenues of reportable segments	$ 814	$ 582	$ 12,184	$ —	$ 13,580
Equity earnings in unconsolidated entities	$ 121	$ —	$ —		$ 121
Segment adjusted EBITDA	$ 571	$ 368	$ 23		$ 962
Maintenance capital	$ 57	$ 66	$ 8		$ 131

(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 for a discussion of our related accounting policy. We have included an estimate of the revenues from these inventory exchanges in our Transportation segment revenue from external customers presented above and adjusted those revenues out such that Total revenue 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.

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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,	
	2018	2017	2018	2017
Segment adjusted EBITDA	$505	$450	$1,097	$962
Adjustments [1]:				
Depreciation and amortization of unconsolidated entities [2]	(14)	(4)	(29)	(18)
Gains/(losses) from derivative activities net of inventory valuation adjustments [3]	(240)	13	(216)	302
Long-term inventory costing adjustments [4]	(5)	(7)	7	(14)
Deficiencies under minimum volume commitments, net [5]	(3)	14	(13)	3
Equity-indexed compensation expense [6]	(12)	(9)	(23)	(12)
Net gain/(loss) on foreign currency revaluation [7]	2	10	(8)	14
Line 901 incident [8]	—	(12)	—	(12)
Significant acquisition-related expenses [9]	—	(1)	—	(6)
Depreciation and amortization	(49)	(129)	(175)	(250)
Interest expense, net	(111)	(127)	(217)	(256)
Other income/(expense), net	11	1	10	(4)
Income before tax	84	199	433	709
Income tax benefit/(expense)	16	(10)	(45)	(76)
Net income	100	189	388	633
Net income attributable to noncontrolling interests	—	(1)	—	(1)
Net income attributable to PAA	$100	$188	$388	$632

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

(2) Includes our proportionate share of the depreciation and amortization and gains and losses on significant asset sales of equity method investments.

(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

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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 from the revaluation of foreign currency transactions and monetary assets and liabilities.

(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.

(9) Includes acquisition-related expenses associated with the acquisition of the Alpha Crude Connector Gathering System (the "ACC Acquisition"). See Note 6 to our Consolidated Financial Statements included in Part IV of our 2017 Annual Report on Form 10-K for additional discussion.

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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 2017 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 2018, we recognized net income attributable to PAA of $388 million as compared to net income attributable to PAA of $632 million recognized during the first six months of 2017. The year-over-year decrease reflects a $511 million negative impact associated with the difference between losses recognized in the 2018 period from the mark-to-market of certain derivative instruments, as compared to gains recognized in the prior period. The 2018 period was also negatively impacted compared to the 2017 period by asset sales completed during 2017 and 2018. These decreases were partially offset by:

- Higher 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;

- Lower depreciation and amortization expense due to net gains recognized during the 2018 period associated with asset sales;

- Lower interest expense driven by a lower weighted average debt balance in the 2018 period as a result of our efforts to implement our Leverage Reduction Plan announced in August 2017. See “—Executive Summary—Overview of Operating Results, Capital Investments and Other Significant Activities” in Item 7 of our 2017 Annual Report on Form 10-K for further discussion of our Leverage Reduction Plan; and

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- Lower income tax expense primarily due to lower year-over-year income as impacted by fluctuations in derivative mark-to-market valuations in our Canadian operations, partially offset by higher taxable earnings in our Canadian operations.

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 $832 million in midstream infrastructure projects during the six months ended June 30, 2018, and we expect expansion capital for the full year of 2018 to be approximately $1.95 billion, which will be primarily focused in the Permian Basin. See the "—Acquisitions and Capital Projects" section below for additional information.

We continued to advance our divestiture program, completing asset sales for total proceeds of approximately $426 million during the six months ended June 30, 2018. We also paid approximately $435 million of cash distributions to our common unitholders during the six months ended June 30, 2018. In addition, we paid distributions of $74 million to our Series A preferred unitholders (of which $37 million was paid in kind and $37 million was paid in cash), and we paid a semi-annual cash distribution of $24.5 million to our Series B preferred unitholders. In July 2018, we declared a quarterly cash distribution of $0.30 per common unit (a total distribution of $218 million) and a quarterly cash distribution of $0.525 per Series A preferred unit (a total distribution of $37 million) to be paid on August 14, 2018.

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,	
	2018	2017
Acquisition capital [(1)] [(2)]	$—	$1,325
Expansion capital [(2)] [(3)]	832	614
Maintenance capital [(3)]	108	131
	$940	$2,070

(1) Acquisition capital for the first six months of 2017 primarily relates to the ACC Acquisition.

(2) Acquisitions of initial investments or additional interests in unconsolidated entities are included in "Acquisition capital." Subsequent 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.

(3) 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 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 2018 and the estimated cost for the year ending December 31, 2018 (in millions):

Projects	2018
Permian Basin Takeaway Pipeline Projects	$925

Complementary Permian Basin Projects	675
Selected Facilities Projects [1]	65
Other Projects	285
Total Projected 2018 Expansion Capital Expenditures [2]	$1,950

[1] Includes projects at our St. James, Fort Saskatchewan and Cushing terminals.

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(2) 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.

We have increased our 2018/2019 expansion capital program primarily due to demand for additional Permian Basin infrastructure, and we expect a majority of this increase to occur in 2018. We have also accelerated into 2018 the construction of some projects initially scheduled for 2019 and have increased costs on certain projects. A portion of the cost increase is attributable to the imposition of steel tariffs on the Cactus II pipeline project.

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	
	2018	2017	$	%	2018	2017	$	%
Transportation segment adjusted EBITDA [1]	$360	$298	$62	21 %	$695	$571	$124	22 %
Facilities segment adjusted EBITDA [1]	171	180	(9)	(5)%	357	368	(11)	(3)%
Supply and Logistics segment adjusted EBITDA [1]	(26)	(28)	2	7 %	45	23	22	96 %
Adjustments:								
Depreciation and amortization of unconsolidated entities	(14)	(4)	(10)	(250)%	(29)	(18)	(11)	(61)%
Selected items impacting comparability - segment adjusted EBITDA	(258)	8	(266)	**	(253)	275	(528)	**
Depreciation and amortization	(49)	(129)	80	62 %	(175)	(250)	75	30 %
Interest expense, net	(111)	(127)	16	13 %	(217)	(256)	39	15 %
Other income/(expense), net	11	1	10	**	10	(4)	14	**
Income tax benefit/(expense)	16	(10)	26	260 %	(45)	(76)	31	41 %
Net income	$100	$189	$(89)	(47)%	$388	$633	$(245)	(39)%
Net income attributable to noncontrolling interests	—	(1)	1	100 %	—	(1)	1	100 %
Net income attributable to PAA	$100	$188	$(88)	(47)%	$388	$632	$(244)	(39)%
Basic net income per common unit	$0.07	$0.21	$(0.14)	**	$0.39	$0.78	$(0.39)	**
Diluted net income per common unit	$0.07	$0.21	$(0.14)	**	$0.39	$0.78	$(0.39)	**
Basic weighted average common units outstanding	725	725	—	**	725	708	17	**
Diluted weighted average common units outstanding	727	727	—	**	727	710	17	**

** 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.

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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 and gains and losses on significant asset sales of unconsolidated entities) and 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 “Accounts payable and accrued 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.

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

	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
	2018	2017	$	%	2018	2017	$	%
Net income	$100	$189	$(89)	(47)%	$388	$633	$(245)	(39)%
Add/(Subtract):								
Interest expense, net	111	127	(16)	(13)%	217	256	(39)	(15)%
Income tax (benefit)/expense	(16)	10	(26)	(260)%	45	76	(31)	(41)%
Depreciation and amortization	49	129	(80)	(62)%	175	250	(75)	(30)%
Depreciation and amortization of unconsolidated entities [(1)]	14	4	10	250 %	29	18	11	61 %
Selected Items Impacting Comparability:								
(Gains)/losses from derivative activities net of inventory valuation adjustments [(2)]	240	(13)	253	**	216	(302)	518	**
Long-term inventory costing adjustments [(3)]	5	7	(2)	**	(7)	14	(21)	**
Deficiencies under minimum volume commitments, net [(4)]	3	(14)	17	**	13	(3)	16	**
Equity-indexed compensation expense [(5)]	12	9	3	**	23	12	11	**
Net (gain)/loss on foreign currency revaluation [(6)]	(2)	(10)	8	**	8	(14)	22	**
Line 901 incident [(7)]	—	12	(12)	**	—	12	(12)	**
Significant acquisition-related expenses [(8)]	—	1	(1)	**	—	6	(6)	**
Selected Items Impacting Comparability - segment adjusted EBITDA	258	(8)	266	**	253	(275)	528	**
(Gains)/losses from derivative activities [(2)]	(8)	(2)	(6)	**	(5)	2	(7)	**
Net (gain)/loss on foreign currency revaluation [(6)]	(2)	2	(4)	**	(4)	3	(7)	**
Selected Items Impacting Comparability - Adjusted EBITDA [(9)]	248	(8)	256	**	244	(270)	514	**
Adjusted EBITDA [(9)]	$506	$451	$55	12 %	$1,098	$963	$135	14 %
Interest expense, net [(10)]	(107)	(121)	14	12 %	(212)	(246)	34	14 %
Maintenance capital [(11)]	(63)	(71)	8	11 %	(108)	(131)	23	18 %
Current income tax expense	(7)	(1)	(6)	**	(20)	(11)	(9)	(82)%
Adjusted equity earnings in unconsolidated entities, net of distributions [(12)]	1	32	(31)	**	15	18	(3)	**
Distributions to noncontrolling interests [(13)]	—	—	—	N/A	—	(1)	1	100 %
Implied DCF [(14)]	$330	$290	40	14 %	$773	$592	181	31 %
Preferred unit distributions [(15)]	(62)	—	(62)	N/A	(62)	—	(62)	N/A
Implied DCF Available to Common Unitholders	$268	$290	$(22)	(8)%	$711	$592	$119	20 %
Common unit cash distributions [(13)]	(218)	(399)			(435)	(770)		
Implied DCF Excess/(Shortage) [(16)]	$50	$(109)			$276	$(178)		

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

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(1) Over the past several years, we have increased our participation in pipeline strategic joint ventures, which are accounted for under the equity method of accounting. We exclude our proportionate share of the depreciation and amortization expense and gains and losses on significant asset sales of 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 11 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 4 to our Consolidated Financial Statements included in Part IV of our 2017 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 16 to our Consolidated Financial Statements included in Part IV of our 2017 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 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 11 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 17 to our Consolidated Financial Statements included in Part IV of our 2017 Annual Report on Form 10-K for additional information regarding the Line 901 incident.

(8) Includes acquisition-related expenses associated with the ACC Acquisition in February 2017.

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(9) Adjusted EBITDA includes Other income/(expense), net adjusted for selected items impacting comparability ("Adjusted Other income/(expense), net"). Segment adjusted EBITDA does not include Adjusted Other income/(expense), net.

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

(11) 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.

(12) Represents the difference between non-cash equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization and gains and losses on significant asset sales) and cash distributions received from such entities.

(13) Cash distributions paid during the period presented.

(14) Including net costs recognized during the period related to the Line 901 incident that occurred in May 2015, Implied DCF would have been $278 million and $580 million for the three and six months ended June 30, 2017, respectively. See Note 17 to our Consolidated Financial Statements included in Part IV of our 2017 Annual Report on Form 10-K for additional information regarding the Line 901 incident.

(15) 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 were paid in cash beginning with 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 11 to our Consolidated Financial Statements included in Part IV of our 2017 Annual Report on Form 10-K for additional information regarding our preferred units.

(16) 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 and gains and losses on significant asset sales of 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.

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.

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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, third-party pipeline capacity agreements and other transportation fees.

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)	2018	2017	$	%	2018	2017	$	%
Revenues	$475	$425	$50	12 %	$929	$814	$115	14 %
Purchases and related costs	(46)	(21)	(25)	(119)%	(92)	(45)	(47)	(104)%
Field operating costs	(157)	(158)	1	1 %	(304)	(299)	(5)	(2)%
Segment general and administrative expenses [2]	(30)	(24)	(6)	(25)%	(58)	(53)	(5)	(9)%
Equity earnings in unconsolidated entities	96	68	28	41 %	171	121	50	41 %
Adjustments [3]:								
Depreciation and amortization of unconsolidated entities	14	4	10	250 %	29	18	11	61 %
Gains from derivative activities	—	—	—	**	(1)	—	(1)	**
Deficiencies under minimum volume commitments, net	1	(14)	15	**	9	(9)	18	**
Equity-indexed compensation expense	7	5	2	**	12	6	6	**
Line 901 incident	—	12	(12)	**	—	12	(12)	**
Significant acquisition-related expenses	—	1	(1)	**	—	6	(6)	**
Segment adjusted EBITDA	$360	$298	$62	21 %	$695	$571	$124	22 %
Maintenance capital	$32	$27	$5	19 %	$61	$57	$4	7 %
Segment adjusted EBITDA per barrel	$0.68	$0.63	$0.05	8 %	$0.69	$0.64	$0.05	8 %

Average Daily Volumes	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
(in thousands of barrels per day) [4]	2018	2017	Volumes	%	2018	2017	Volumes	%
Tariff activities volumes								
Crude oil pipelines (by region):								
Permian Basin [5]	3,734	2,761	973	35 %	3,489	2,614	875	33 %
South Texas / Eagle Ford [5]	434	349	85	24 %	428	330	98	30 %
Central [5]	448	427	21	5 %	445	416	29	7 %
Gulf Coast	170	385	(215)	(56)%	187	364	(177)	(49)%
Rocky Mountain [5]	270	444	(174)	(39)%	263	415	(152)	(37)%
Western	181	179	2	1 %	177	184	(7)	(4)%
Canada	298	363	(65)	(18)%	308	363	(55)	(15)%
Crude oil pipelines	5,535	4,908	627	13 %	5,297	4,686	611	13 %
NGL pipelines	171	156	15	10 %	172	168	4	2 %
Tariff activities total volumes	5,706	5,064	642	13 %	5,469	4,854	615	13 %
Trucking volumes	91	99	(8)	(8)%	95	106	(11)	(10)%
Transportation segment total volumes	5,797	5,163	634	12 %	5,564	4,960	604	12 %

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** 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.

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. As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor. We recognize the allowance volumes collected at fair value.

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:

(in millions)	Favorable/(Unfavorable) Variance Three Months Ended June 30, 2018-2017			Favorable/(Unfavorable) Variance Six Months Ended June 30, 2018-2017		
	Revenues	Purchases and Related Costs	Equity Earnings	Revenues	Purchases and Related Costs	Equity Earnings
Permian Basin region	$ 64	$ (22)	$ 15	$ 134	$ (45)	$ 23
South Texas / Eagle Ford region	4	—	8	6	—	12
Central region	(7)	—	11	(11)	—	22
Gulf Coast region	(11)	—	—	(18)	—	—
Rocky Mountain region	(12)	—	1	(17)	—	(1)
Other (including trucking and pipeline loss allowance revenue)	12	(3)	(7)	21	(2)	(6)
Total variance	$ 50	$ (25)	$ 28	$ 115	$ (47)	$ 50

- Permian Basin region. Total revenues, net of purchases and related costs, and equity earnings in unconsolidated entities increased by approximately $57 million and $112 million, respectively, for the three and six month comparative periods primarily due to higher volumes from increased production and our recently completed capital expansion projects. For the three and six months ended June 30, 2018, these increases included (i) higher volumes of approximately 360,000 and 333,000 barrels per day, respectively, on our gathering systems, including our ACC system acquired in February 2017, (ii) higher volumes of approximately 424,000 and 367,000 barrels per day, respectively, on our intra-basin pipelines and (iii) a volume increase of approximately 189,000 and 175,000 barrels per day, respectively, on our long-haul pipelines, including our 50% equity interest in BridgeTex.

- South Texas / Eagle Ford region. Equity earnings from our 50% interest in Eagle Ford Pipeline LLC increased for each of the comparative periods presented primarily due to higher volumes from our Cactus pipeline.

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- Central region. The decrease in revenues for each of the comparative periods was primarily due to the sale of certain of our Mid-Continent Area System assets in the fourth quarter of 2017, including the sale of a portion of our interest in our Midway pipeline for which our remaining interest is now accounted for under the equity method of accounting.

Equity earnings increased for each of the comparative periods from (i) our 50% interest in the Diamond joint venture pipeline, which was placed in service in late 2017, and (ii) our 50% interest in Midway pipeline, which we now account for under the equity method of accounting following the sale of a portion of our interest in the pipeline in the fourth quarter of 2017, as discussed above.

- Gulf Coast Region. The decrease in revenues for each of the comparative periods was primarily due to lower volumes on the Capline pipeline, resulting from the movement of volumes to the Diamond joint venture pipeline, which was placed in service in late 2017.

- Rocky Mountain Region. The decrease in revenues for each of the comparative periods was primarily due to the sale of certain pipelines and related assets in the fourth quarter of 2017 and the second quarter of 2018.

- Other. The increase in other revenue for each of the comparative periods was primarily due to greater pipeline loss allowance revenue driven by higher volumes in the 2018 periods. The impact on revenues from the decrease in volumes on our Canadian crude oil pipelines for the comparative periods was partially offset by increased tariff rates on certain of our Canadian crude oil pipelines as well as favorable foreign exchange impacts.

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, based on an expectation of continued production growth, agreed to either: (i) ship and pay for certain stated volumes or (ii) pay the agreed upon price for a minimum contract quantity. During the 2018 periods presented in the table above, we had net collections for deficiencies under minimum volume commitments resulting in deferred revenues and an increase to Segment Adjusted EBITDA. In the 2017 periods, (i) shippers utilized credits associated with previous deficiencies or (ii) credits expired resulting in the recognition of previously deferred revenue, which were partially offset by collections for deficiencies under minimum volume commitments resulting in a net decrease to segment adjusted EBITDA.

Field Operating Costs. Field operating costs for the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017 were impacted by an increase in power costs resulting from higher volumes, and increases in compensation costs, which were fully offset in the three-month comparative period and partially offset in the six-month comparative period by the impact of an increase of estimated costs recognized in the second quarter of 2017 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) as well as the sale of assets in the Rocky Mountain region in the fourth quarter of 2017 and the second quarter of 2018. To a much lesser extent, the increase for the six-month period ended June 30, 2018 was also due to a full period of operations from the ACC gathering system acquired in February 2017.

Segment General and Administrative Expenses. The increase in segment general and administrative expenses for the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017 was primarily driven by an increase in equity-indexed compensation expense due to the impact of an increase in unit price for the 2018 periods compared to a decrease in unit price for the 2017 periods. The increase for the six-month comparative period was partially offset by acquisition costs incurred in the 2017 period related to the ACC gathering system acquisition (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, 2018 compared to the same periods in 2017 was primarily due to an operational tank replacement project.

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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] (in millions, except per barrel data)	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Variance $	Variance %	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Variance $	Variance %
Revenues	$284	$289	$(5)	(2)%	$576	$582	$(6)	(1)%
Purchases and related costs	(3)	(6)	3	50 %	(8)	(17)	9	53 %
Field operating costs	(92)	(85)	(7)	(8)%	(176)	(169)	(7)	(4)%
Segment general and administrative expenses [2]	(21)	(18)	(3)	(17)%	(42)	(37)	(5)	(14)%
Adjustments [3]:								
(Gains)/losses from derivative activities	(1)	(1)	—	**	(2)	1	(3)	**
Deficiencies under minimum volume commitments, net	2	—	2	**	4	6	(2)	**
Equity-indexed compensation expense	2	1	1	**	5	2	3	**
Segment adjusted EBITDA	$171	$180	$(9)	(5)%	$357	$368	$(11)	(3)%
Maintenance capital	$26	$39	$(13)	(33)%	$41	$66	$(25)	(38)%
Segment adjusted EBITDA per barrel	$0.46	$0.45	$0.01	2 %	$0.48	$0.47	$0.01	2 %

Volumes [4]	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Variance Volumes	Variance %	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Variance Volumes	Variance %
Liquids storage (average monthly capacity in millions of barrels)	109	112	(3)	(3)%	109	112	(3)	(3)%
Natural gas storage (average monthly working capacity in billions of cubic feet) [5]	65	97	(32)	(33)%	66	97	(31)	(32)%
NGL fractionation (average volumes in thousands of barrels per day)	132	119	13	11 %	135	122	13	11 %
Facilities segment total volumes (average monthly volumes in millions of barrels) [6]	124	132	(8)	(6)%	124	132	(8)	(6)%

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

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

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

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 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.

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(5) The decrease in average monthly working capacity of natural gas storage facilities was driven by adjustments for (i) the sale of our Bluewater natural gas storage facility in June 2017, (ii) changes in base gas and (iii) 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. Variances in revenues, purchases and related costs and average monthly volumes for the comparative periods were driven by:

- NGL Operations. Revenues increased by $1 million and $13 million for the three and six months ended June 30, 2018, respectively, over the same periods in 2017 primarily due to (i) increased volumes and fees associated with placing an additional 1.6 million barrels of NGL storage capacity into service in the second half of 2017 at our Fort Saskatchewan facility, (ii) higher volumetric gains at certain facilities in the 2018 periods, (iii) a favorable foreign exchange impact of approximately $4 million and $9 million for the three and six month comparative periods, respectively. Such increases were partially offset by (i) decreases in fees at certain of our storage and fractionation facilities and (ii) the sale of a natural gas processing facility in the second quarter of 2018.

- Rail Terminals. Revenues increased by $2 million and $10 million for the three and six months ended June 30, 2018, respectively, over the same periods in 2017 primarily due to higher activity at certain of our rail terminals resulting from more favorable market conditions.

- Crude Oil Storage. Revenues decreased by $5 million and $13 million for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017 primarily due to the sale of certain of our Bay Area, California terminal assets in December 2017. These negative results were partially offset in both comparative periods by higher revenues from our Cushing terminal largely driven by increased throughout and capacity expansions of approximately 1 million barrels.

- Natural Gas Storage. Revenues, net of purchases and related costs, decreased by $8 million for the six-month comparative period primarily due to (i) the June 2017 sale of our Bluewater natural gas storage facility and (ii) the absence of a one-time fee recognized during the first quarter of 2017 related to the early termination of a storage contract at our Pine Prairie facility.

Field Operating Costs. The increase in field operating costs for the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017 was primarily due to an increase in personnel costs, partially offset by lower costs due to the sale of assets.

Segment General and Administrative Expenses. The increase in segment general and administrative expenses for the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017 was primarily driven by an increase in equity-indexed compensation expense due to the impact of an increase in unit price for the 2018 periods compared to a decrease in unit price for the 2017 periods.

Maintenance Capital. The decrease in maintenance capital for the three and six months ended June 30, 2018 compared to the same periods in 2017 was primarily due to higher expenditures related to our integrity management program in 2017, primarily on assets at our Southern California terminals. Total maintenance costs related to our integrity management program at these terminals decreased by approximately $18 million and $31 million for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. We expect to continue to see significant reductions to our maintenance capital costs compared to 2017 at these terminals going forward as we complete a number of maintenance projects in this area.

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Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes and natural gas sales attributable to activities that were previously performed by the natural gas storage commercial optimization group. 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 effects of competition on our lease gathering and NGL margins and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although our segment results may be adversely affected during certain transitional periods as discussed further below, our crude oil and NGL supply, logistics and distribution operations are not directly affected by the absolute level of prices, but are affected by overall levels of supply and demand for crude oil and NGL, market structure and relative fluctuations in market-related indices and regional differentials.

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)	2018	2017	$	%	2018	2017	$	%
Revenues	$7,781	$5,783	$1,998	35 %	$15,893	$12,184	$3,709	30 %
Purchases and related costs	(7,959)	(5,708)	(2,251)	(39)%	(15,884)	(11,678)	(4,206)	(36)%
Field operating costs	(66)	(65)	(1)	(2)%	(131)	(132)	1	1 %
Segment general and administrative expenses [2]	(29)	(26)	(3)	(12)%	(59)	(52)	(7)	(13)%
Adjustments [3]:								
(Gains)/losses from derivative activities net of inventory valuation adjustments	241	(12)	253	**	219	(303)	522	**
Long-term inventory costing adjustments	5	7	(2)	**	(7)	14	(21)	**
Equity-indexed compensation expense	3	3	—	**	6	4	2	**
Net (gain)/loss on foreign currency revaluation	(2)	(10)	8	**	8	(14)	22	**
Segment adjusted EBITDA	$(26)	$(28)	$2	7 %	$45	$23	$22	96 %
Maintenance capital	$5	$5	$—	— %	$6	$8	$(2)	(25)%
Segment adjusted EBITDA per barrel	$(0.24)	$(0.27)	$0.03	11 %	$0.19	$0.11	$0.08	73 %

Average Daily Volumes [4]	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
(in thousands of barrels per day)	2018	2017	Volumes	%	2018	2017	Volumes	%
Crude oil lease gathering purchases	1,028	940	88	9 %	1,030	929	101	11 %
NGL sales	174	210	(36)	(17)%	266	280	(14)	(5)%
Supply and Logistics segment total volumes	1,202	1,150	52	5 %	1,296	1,209	87	7 %

** 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.

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(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, 2018	$ 62	$ 74
Three months ended June 30, 2017	$ 43	$ 53
Six months ended June 30, 2018	$ 59	$ 74
Six months ended June 30, 2017	$ 43	$ 54

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. The absolute amount of our revenues and purchases increased for the three and six months ended June 30, 2018 compared to the same periods in 2017 primarily due to higher crude oil prices. Additionally, 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.

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

Segment Adjusted EBITDA and Volumes. Our Supply and Logistics Segment Adjusted EBITDA increased by $2 million and $22 million for the three and six months ended June 30, 2018, respectively, compared to the three and six months ended June 30, 2017. The following summarizes the significant items impacting the comparative periods:

- NGL Operations. Net revenues from our NGL operations increased for the three and six months ended June 30, 2018, compared to the same periods in 2017, after offsetting lower volumes in each period, primarily due to (i) lower supply costs at our straddle plants relative to NGL values, (ii) favorable impacts from a wider isobutane/normal butane differential and (iii) modifications made to our contracting strategies in the 2017-2018 heating season.

- Crude Oil Operations. Net revenues from our crude oil supply and logistics operations were relatively consistent for the comparative three-month periods and the comparative six-month periods presented, as arbitrage opportunities in certain markets during the 2018 periods were substantially offset by lower lease gathering margins resulting from competition for wellhead volumes, as well as the absence of the contango market conditions experienced in 2017.

- 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) and inventory valuation adjustments, as applicable. See Note 11 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.

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- 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 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.

- Segment General and Administrative Expenses. The increase in segment general and administrative expenses for the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017 was primarily driven by (i) an increase in equity-indexed compensation expense due to the impact of an increase in unit price for the 2018 periods compared to a decrease in unit price for the 2017 periods and (ii) cost increases across various categories.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense decreased for the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017 primarily due to net gains of approximately $81 million recognized during the second quarter of 2018, which were primarily associated with asset sales during the periods.

Interest Expense

The decrease in interest expense for the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017 was primarily due to a lower weighted average debt balance during the 2018 periods resulting from the repayment of an aggregate of $950 million senior notes in December 2017.

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,	
	2018	2017	2018	2017
Gain/(loss) related to mark-to-market adjustment of our Preferred Distribution Rate Reset Option [(1)]	$8	$ 2	$5	$ (2)
Other	3	(1)	5	(2)
	$11	$ 1	$10	$ (4)

(1) See Note 11 to our Condensed Consolidated Financial Statements for additional information.

Income Tax Expense

Income tax expense decreased for the three and six months ended June 30, 2018 as compared to the three and six months ended June 30, 2017, primarily due to lower year-over-year income as impacted by fluctuations in derivative mark-to-market valuations in our Canadian operations, partially offset by higher taxable earnings in our Canadian operations.

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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 "—Capital Expenditures and Divestitures." 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, 2018, we had a working capital deficit of $1.3 billion, which we anticipate will decrease in future quarters. We do not expect that the decrease will result in the use of a significant amount of our credit facility borrowing capacity to meet the obligations as a large portion of the anticipated decrease will be funded from incremental cash flow from our operations. In addition, as of June 30, 2018, we had over $3.0 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, 2018
Availability under senior unsecured revolving credit facility [1] [2]	$1,335
Availability under senior secured hedged inventory facility [1] [2]	922
Availability under senior unsecured 364-day revolving credit facility [3]	1,000
Amounts outstanding under commercial paper program	(259)
Subtotal	2,998
Cash and cash equivalents	34
Total	$3,032

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

(2) Available capacity under the senior unsecured revolving credit facility and the senior secured hedged inventory facility was reduced by outstanding letters of credit of $140 million and $28 million, respectively.

(3) The senior unsecured 364-day revolving credit facility matures in mid-August 2018.

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, 2018, we were in compliance with all such covenants. Also, see Item 1A. "Risk Factors" of our 2017 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 2017 Annual Report on Form 10-K.

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Net cash provided by operating activities for the first six months of 2018 and 2017 was $1.015 billion and $1.461 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, 2018, net cash provided by operating activities was positively impacted by approximately $300 million of cash received for transactions for which the revenue has been deferred pending the completion of future performance obligations. See Note 3 to our Condensed Consolidated Financial Statements for additional information. 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.

During the six months ended June 30, 2017, we decreased both the volume of inventory that we held and the margin balances required as part of our hedging activities, both of which had been funded by short-term debt. The cash inflows associated with these items resulted in a favorable impact on our cash provided by operating activities. However, the favorable effects from such activities were partially offset by higher prices for NGL and crude oil inventory that was purchased and stored at the end of the period.

Capital Expenditures and Divestitures

In addition to our operating needs discussed above, we also use cash for our acquisition activities and expansion capital projects. 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 the near term, we also intend to use proceeds from our divestiture program, as discussed further below. We have made and will continue to make capital expenditures for acquisitions, expansion capital projects and maintenance activities.

Capital Projects. We invested approximately $832 million in midstream infrastructure during the six months ended June 30, 2018, and we expect to invest approximately $1.95 billion during the full year ended December 31, 2018. See "—Acquisitions and Capital Projects" for detail of our projected capital expenditures for the year ending December 31, 2018. We expect to fund our 2018 capital program with retained cash flow and proceeds from our divestiture program, as discussed further below.

Divestitures. In 2016, we initiated a program to evaluate potential sales of non-core assets and/or sales of partial interests in assets to strategic joint venture partners to optimize our asset portfolio and strengthen our balance sheet and leverage metrics. As of December 31, 2017, we had completed asset sales totaling approximately $1.7 billion, of which approximately $0.6 billion closed in 2016 (net of amounts paid for the remaining interest in a pipeline that was subsequently sold) and approximately $1.1 billion closed in 2017.

As part of our funding plans for our 2018 expansion capital program, we set a target to raise $700 million through divestitures in 2018. We received proceeds of $426 million during the first six months of 2018, and we continue to advance efforts with respect to a number of additional transactions and believe successful consummation of such efforts will enable us to meet and potentially exceed our targeted amounts for 2018. Any excess proceeds above our targeted amounts would be used to reduce debt or fund incremental expansion opportunities.

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 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 divestiture efforts will be successfully completed. Also, see Item 1A. “Risk Factors—Risks Related to Our Business” of our 2017 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, as well as payment of distributions to our unitholders.

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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 $2.0 billion of debt or equity securities ("Traditional Shelf"). At June 30, 2018, 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, 2018.

Credit Agreements, Commercial Paper Program and Indentures. Our credit agreements (which impact our ability to access our commercial paper program because they provide the financial backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements 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, 2018, we were in compliance with the covenants contained in our credit agreements and indentures.

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.

During the six months ended June 30, 2017, we had net repayments on our credit facilities and commercial paper program of $425 million. The net repayments resulted primarily from cash flow from operating activities and cash received from our equity activities, which offset borrowings during the period related to funding needs for (i) acquisition and capital investments, (ii) repayment of our $400 million, 6.13% senior notes in January 2017 and (iii) other general partnership purposes.

Distributions to Our Unitholders

Distributions to our Series A preferred unitholders. On August 14, 2018 we will pay a cash distribution of $37 million ($0.525 per unit) on our Series A preferred units outstanding as of July 31, 2018, the record date for such distribution for the period from April 1, 2018 through June 30, 2018. See Note 10 to our Condensed Consolidated Financial Statements for details of distributions made during or pertaining to the first six months of 2018.

Distributions to Series B preferred unitholders. Distributions on our Series B preferred units are payable semiannually in arrears on the 15th day of May and November. See Note 10 to our Condensed Consolidated Financial Statements for details of distributions made during the first six months of 2018.

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 available cash also includes cash on hand resulting from borrowings made after the end of the quarter. On August 14, 2018, we will pay a quarterly distribution of $0.30 per common unit ($1.20 per common unit on an annualized basis), which is unchanged from our prior three quarterly distributions, but represents a year-over-year distribution decrease of approximately 45% compared to the quarterly distribution of $0.55 per common unit ($2.20 per common unit on an annualized basis) paid in August 2017. See Note 10 to our Condensed Consolidated Financial Statements for details of distributions paid during or pertaining to the first six months of 2018. 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 2017 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.

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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, 2018 (in millions):

	Remainder of 2018	2019	2020	2021	2022	2023 and Thereafter	Total
Long-term debt and related interest payments (1)	$ 207	$913	$872	$942	$1,097	$ 9,985	$14,016
Leases, rights-of-way easements and other (2)	95	154	128	108	87	358	930
Other obligations (3)	506	489	218	173	126	418	1,930
Subtotal	808	1,556	1,218	1,223	1,310	10,761	16,876
Crude oil, NGL and other purchases (4)	5,054	5,416	4,194	3,834	3,293	10,106	31,897
Total	$ 5,862	$6,972	$5,412	$5,057	$4,603	$ 20,867	$48,773

(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 facilities and commercial paper program. Although there may be short-term borrowings under our credit facilities 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 facilities or commercial paper program) in the amounts above. For additional information regarding our debt obligations, see Note 9 to our Condensed Consolidated Financial Statements.

(2) Leases are primarily for (i) railcars, (ii) land and surface rentals, (iii) office buildings, (iv) pipeline assets and (v) vehicles and trailers. Includes operating and capital leases as defined by FASB guidance, as well as obligations for rights-of-way easements.

(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements and (iii) non-cancelable 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 $785 million associated with 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.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during June 2018. 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, 2018 and December 31, 2017, we had outstanding letters of credit of approximately $168 million and $166 million, respectively.

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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 2017 Annual Report on Form 10-K.

Other Items

In March 2018, the Federal Energy Regulatory Commission ("FERC") issued a revised policy statement (subsequently modified in a final rule issued in July 2018) in which it held that it will no longer permit an income tax allowance to be included in cost-of-service rates for interstate pipelines structured as master limited partnerships. The FERC also indicated that it will incorporate the effects of the revised policy statement in its next review of the oil pipeline index level, which will take effect in July 2021. We do not have cost-of-service rates that would be impacted by this policy change; our FERC regulated tariffs are either grandfathered or based on negotiated rates. However, depending on how the FERC incorporates its most recent tax policy statement into its next index review, the policy could potentially have a negative impact on the FERC adder to the PPI-FG Index, which in turn could have a negative effect on our ability to increase our index-based rates. The policy could impact future (i.e., July 2021 and later) tariff escalations on our FERC regulated pipelines, as well as some of our state regulated pipelines that have negotiated rates with escalations tied to the FERC Index.

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" a "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;

- 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);

- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- 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 and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event, including attacks on our electronic and computer systems;

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- 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;
- the failure to consummate, or significant delay in consummating, sales of assets or interests as a part of our strategic divestiture program;
- 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;
- factors affecting demand for natural gas and natural gas storage services and rates;
- 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 2017 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.

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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 exchange-traded and over-the-counter 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 exchange-traded 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 exchange-traded and over-the-counter futures, forwards, swaps and options.

See Note 11 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, 2018 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	$ (317)	$ 56	$ (55)
Natural gas	(19)	$ 8	$ (8)
NGL and other	(125)	$ (71)	$ 71
Total fair value	$ (461)		

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, 2018, approximately $835 million, was subject to interest rate re-sets that range from one day to approximately one week. The average interest rate on variable rate debt that was outstanding during the six months ended June 30, 2018 was 2.8%, based upon rates in effect during such period. The fair value of our interest rate derivatives was a liability of less than $1 million as of June 30, 2018. A 10% increase in the forward LIBOR curve as of June 30, 2018 would have resulted in an increase of $22 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of June 30, 2018 would have resulted in a decrease of $22 million to the fair value of our interest rate derivatives. See Note 11 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 a liability of $7 million as of June 30, 2018. A 10% increase in the exchange rate (USD-to-CAD) would have resulted in an increase of $18 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would have resulted in a decrease of $18 million to the fair value of our foreign currency derivatives. See Note 11 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 $17 million as of June 30, 2018. A 10% increase or decrease in the fair value would have an impact of $2 million. See Note 11 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, 2018, the end of the period covered by this report, and, based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our DCP is effective.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting during the second quarter of 2018 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.

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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 2017 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

Pursuant to the Omnibus Agreement entered into in November 2016 by and among us, our general partner, GP LLC, AAP, PAGP and its general partner as part of the Simplification Transactions, we agreed 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. See Note 1 to our Consolidated Financial Statements included in Part IV of our 2017 Annual Report on Form 10-K for information regarding the Simplification Transactions.

During the quarter ended June 30, 2018, we issued 375,835 common units to AAP associated with AAP Management Units that became earned as of March 31, 2018. 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.

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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	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).

3.12	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).
3.13	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).
3.14	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).
3.15	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).
3.16	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).
3.17	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).

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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).

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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).
10.1 *	Second Amendment dated March 22, 2018 to Plains AAP, L.P. Class B Restricted Units Agreement (Willie Chiang) (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
10.2 *	Form of First Amendment dated March 22, 2018 to Amended and Restated Plains AAP, L.P. Class B Restricted Units Agreement dated August 25, 2016 (Officers) (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
10.3 *	Amendment dated March 22, 2018 to PAA LTIP Grant Letter dated August 24, 2015 (Willie Chiang) (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
10.4 *	Form of Amendment dated March 22, 2018 to PAA LTIP Grant Letter dated August 25, 2016 (Officers) (incorporated by reference to Exhibit 10.4 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
10.5 *	Form of PAA LTIP Grant Letter for Officers (March 2018) (incorporated by reference to Exhibit 10.5 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
12.1 †	Statement of Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Unit Distributions.
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
101.SCH†	XBRL Taxonomy Extension Schema Document

101.CAL† — XBRL Taxonomy Extension Calculation Linkbase Document

101.DEF† — XBRL Taxonomy Extension Definition Linkbase Document

101.LAB† — XBRL Taxonomy Extension Label Linkbase Document

101.PRE† — XBRL Taxonomy Extension Presentation Linkbase Document

† Filed herewith.
†† Furnished herewith.
* Management compensatory plan or arrangement.

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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/ Greg L. Armstrong
Greg L. Armstrong,
Chief Executive Officer of Plains All American GP LLC
(Principal Executive Officer)

August 8, 2018

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

August 8, 2018

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

August 8, 2018