UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2017

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. ☒ 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). ☒ Yes o No

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

Large accelerated filer ☒	Accelerated filer 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 Yes o No

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

As of July 31, 2017, there were 724,696,735 Common Units outstanding.

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

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	June 30, 2017	December 31, 2016
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 47	$ 47
Trade accounts receivable and other receivables, net	2,088	2,279
Inventory	936	1,343
Other current assets	457	603
Total current assets	3,528	4,272
PROPERTY AND EQUIPMENT	16,850	16,220
Accumulated depreciation	(2,528)	(2,348)
Property and equipment, net	14,322	13,872
OTHER ASSETS		
Goodwill	2,596	2,344
Investments in unconsolidated entities	2,626	2,343
Linefill and base gas	894	896
Long-term inventory	117	193
Other long-term assets, net	921	290
Total assets	$ 25,004	$ 24,210
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,349	$ 2,588
Short-term debt	1,114	1,715
Other current liabilities	294	361
Total current liabilities	3,757	4,664
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discounts and debt issuance costs	9,878	9,874
Other long-term debt	162	250
Other long-term liabilities and deferred credits	706	606
Total long-term liabilities	10,746	10,730
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS' CAPITAL		
Series A preferred unitholders (66,990,153 and 64,388,853 units outstanding, respectively)	1,507	1,508
Common unitholders (724,696,735 and 669,194,419 units outstanding, respectively)	8,937	7,251
Total partners' capital excluding noncontrolling interests	10,444	8,759
Noncontrolling interests	57	57
Total partners' capital	10,501	8,816
Total liabilities and partners' capital	$ 25,004	$ 24,210

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

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

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$ 5,781	$ 4,648	$ 12,176	$ 8,467
Transportation segment revenues	161	170	299	323
Facilities segment revenues	136	132	270	270
Total revenues	6,078	4,950	12,745	9,060
COSTS AND EXPENSES				
Purchases and related costs	5,320	4,224	10,912	7,571
Field operating costs	304	303	593	603
General and administrative expenses	68	73	142	140
Depreciation and amortization	129	204	250	319
Total costs and expenses	5,821	4,804	11,897	8,633
OPERATING INCOME	257	146	848	427
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	68	40	121	87
Interest expense (net of capitalized interest of $9, $12, $15 and $26, respectively)	(127)	(114)	(256)	(227)
Other income/(expense), net	1	25	(4)	30
INCOME BEFORE TAX	199	97	709	317
Current income tax expense	(1)	(9)	(11)	(40)
Deferred income tax benefit/(expense)	(9)	14	(65)	27
NET INCOME	189	102	633	304
Net income attributable to noncontrolling interests	(1)	(1)	(1)	(2)
NET INCOME ATTRIBUTABLE TO PAA	$ 188	$ 101	$ 632	$ 302
NET INCOME/(LOSS) PER COMMON UNIT (NOTE 3):				
Net income/(loss) allocated to common unitholders — Basic	$ 148	$ (81)	$ 555	$ (53)
Basic weighted average common units outstanding	725	398	708	398
Basic net income/(loss) per common unit	$ 0.21	$ (0.20)	$ 0.78	$ (0.13)
Net income/(loss) allocated to common unitholders — Diluted	$ 148	$ (81)	$ 555	$ (53)
Diluted weighted average common units outstanding	727	398	710	398
Diluted net income/(loss) per common unit	$ 0.21	$ (0.20)	$ 0.78	$ (0.13)

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(unaudited)		(unaudited)	
Net income	$ 189	$ 102	$ 633	$ 304
Other comprehensive income/(loss)	75	(73)	111	45
Comprehensive income	264	29	744	349
Comprehensive income attributable to noncontrolling interests	(1)	(1)	(1)	(2)
Comprehensive income attributable to PAA	$ 263	$ 28	$ 743	$ 347

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, 2016	$ (228)	$ (782)	$ 1	$ (1,009)
Reclassification adjustments	9	—	—	9
Deferred loss on cash flow hedges	(12)	—	—	(12)
Currency translation adjustments	—	114	—	114
Total period activity	(3)	114	—	111
Balance at June 30, 2017	$ (231)	$ (668)	$ 1	$ (898)

	Derivative Instruments	Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2015	$ (203)	$ (878)	$ (1,081)
Reclassification adjustments	6	—	6
Deferred loss on cash flow hedges	(158)	—	(158)
Currency translation adjustments	—	197	197
Total period activity	(152)	197	45
Balance at June 30, 2016	$ (355)	$ (681)	$ (1,036)

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, 2017	Six Months Ended June 30, 2016
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 633	$ 304
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	250	319
Equity-indexed compensation expense	22	26
Inventory valuation adjustments	35	3
Deferred income tax (benefit)/expense	65	(27)
Gain on foreign currency revaluation	(11)	(2)
Settlement of terminated interest rate hedging instruments	(29)	(50)
Change in fair value of Preferred Distribution Rate Reset Option (Note 10)	2	(25)
Equity earnings in unconsolidated entities	(121)	(87)
Distributions on earnings from unconsolidated entities	136	101
Other	14	6
Changes in assets and liabilities, net of acquisitions	465	(181)
Net cash provided by operating activities	1,461	387
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(1,281)	(85)
Investments in unconsolidated entities	(250)	(120)
Additions to property, equipment and other	(549)	(699)
Proceeds from sales of assets	389	391
Return of investment from unconsolidated entities	21	—
Other investing activities	16	(9)
Net cash used in investing activities	(1,654)	(522)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) under commercial paper program (Note 8)	25	(844)
Net borrowings/(repayments) under senior secured hedged inventory facility (Note 8)	(450)	252
Repayments of senior notes (Note 8)	(400)	—
Net proceeds from the sale of Series A preferred units	—	1,569
Net proceeds from the sale of common units (Note 9)	1,664	—
Contributions from general partner	—	33
Distributions paid to common unitholders (Note 9)	(770)	(557)
Distributions paid to general partner	—	(309)
Other financing activities	123	(6)
Net cash provided by financing activities	192	138
Effect of translation adjustment on cash	1	4
Net increase in cash and cash equivalents	—	7
Cash and cash equivalents, beginning of period	47	27
Cash and cash equivalents, end of period	$ 47	$ 34
Cash paid for:		
Interest, net of amounts capitalized	$ 252	$ 225
Income taxes, net of amounts refunded	$ 34	$ 51

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

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

	Limited Partners		Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Series A Preferred Unitholders	Common Unitholders			
			(unaudited)		
Balance at December 31, 2016	$ 1,508	$ 7,251	$ 8,759	$ 57	$ 8,816
Net income	—	632	632	1	633
Cash distributions to partners	—	(770)	(770)	(1)	(771)
Sales of common units	—	1,664	1,664	—	1,664
Acquisition of interest in Advantage Joint Venture (Note 6)	—	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

	Limited Partners		General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Series A Preferred Unitholders	Common Unitholders				
				(unaudited)		
Balance at December 31, 2015	$ —	$ 7,580	$ 301	$ 7,881	$ 58	$ 7,939
Net income	—	11	291	302	2	304
Cash distributions to partners	—	(557)	(309)	(866)	(2)	(868)
Sale of Series A preferred units	1,509	—	33	1,542	—	1,542
Other comprehensive income	—	44	1	45	—	45
Other	—	7	1	8	—	8
Balance at June 30, 2016	$ 1,509	$ 7,085	$ 318	$ 8,912	$ 58	$ 8,970

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

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 for crude oil, natural gas liquids (“NGL”), natural gas and refined products. 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 13 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, 2017, AAP also owned an approximate 36% limited partner interest in us represented by approximately 288.3 million of our common units. 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, 2017, owned, directly and indirectly, an approximate 53% 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 (“PMC”).

References to the “PAGP Entities” include PAGP GP, PAGP, GP LLC, AAP and PAA GP. References to our “general partner,” as the context requires, include any or all of the PAGP Entities. References to the “Plains Entities” include us, our subsidiaries and the PAGP Entities.

Simplification Transactions

On November 15, 2016, the Plains Entities closed a series of transactions and executed several organizational and ancillary documents (the “Simplification Transactions”) intended to simplify our capital structure, better align the interests of our stakeholders and improve our overall credit profile. The Simplification Transactions included, among other things:

- the permanent elimination of our incentive distribution rights (“IDRs”) and the economic rights associated with our 2% general partner interest in exchange for the issuance by us to AAP of 245.5 million PAA common units (including approximately 0.8 million units to be issued in the future) and the assumption by us of all of AAP’s outstanding debt ($642 million);

- the implementation of a unified governance structure pursuant to which the board of directors of GP LLC was eliminated and an expanded board of directors of PAGP GP assumed oversight responsibility over both us and PAGP;

- the provision for annual PAGP shareholder meetings beginning in 2018 for the purpose of electing certain directors with expiring terms in 2018, and the participation of our common unitholders and Series A preferred unitholders in such elections through our ownership of newly issued Class C shares in PAGP, which provide us, as the sole holder of such Class C shares, the right to vote in elections of eligible PAGP directors together with the holders of PAGP Class A and Class B shares;

- the execution by AAP of a reverse split to adjust the number of AAP Class A units (“AAP units”) such that the number of outstanding AAP units (assuming the conversion of AAP Class B units (the “AAP Management Units”) into AAP units) equaled the number of our common units received by AAP at the closing of the Simplification Transactions. Simultaneously, PAGP executed a reverse split to adjust the number of PAGP Class A and Class B shares outstanding to equal the number of AAP units it owns following AAP's reverse unit split. These reverse splits, along with the Omnibus Agreement, resulted in economic alignment between our common unitholders and PAGP's Class A shareholders, such that the number of outstanding PAGP Class A shares equals the number of AAP units owned by PAGP, which in turn equals the number of our common units held by AAP that are attributable to PAGP's interest in AAP. The Plains Entities also entered into an Omnibus Agreement, pursuant to which such one-to-one relationship will be maintained subsequent to the closing of the Simplification Transactions; and

- the creation of a right for certain holders of the AAP units to cause AAP to redeem such AAP units in exchange for an equal number of our common units held by AAP.

The Simplification Transactions were between and among consolidated subsidiaries of PAGP that are considered entities under common control. These equity transactions did not result in a change in the carrying value of the underlying assets and liabilities.

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
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 2016 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, 2016 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, 2017 should not be taken as indicative of results to be expected for the entire year.

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

Note 2—Recent Accounting Pronouncements

Except as discussed below and in our 2016 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, 2017 that are of significance or potential significance to us.

Accounting Standards Updates Adopted During the Period

In March 2016, the FASB issued ASU 2016-09, *Compensation — Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*, which simplified several aspects of the accounting for share-based payment transactions, including the income tax consequences, forfeitures, classification of awards as either equity or liabilities and classification of certain related payments on the statement of cash flows. This guidance was effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. We adopted the applicable provisions of the ASU on January 1, 2017 and (i) elected to account for forfeitures as they occur, utilizing the modified retrospective approach of adoption, and (ii) will classify units directly withheld for tax-withholding purposes as a financing activity on our Condensed Consolidated Statement of Cash Flows for all periods presented. Our adoption did not have a material impact on our financial position, results of operations or cash flows for the periods presented.

In January 2017, the FASB issued ASU 2017-04, *Intangibles — Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*. The amendments within this ASU eliminate Step 2 from the goodwill impairment test, which currently requires an entity to determine goodwill impairment by calculating the implied fair value of goodwill by hypothetically assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. Under the amended standard, goodwill impairment will instead be measured using Step 1 of the goodwill impairment test with goodwill impairment being equal to the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying value of goodwill. This guidance is effective for annual periods beginning after December 15, 2019, and interim periods within those annual periods, with early adoption permitted. We early adopted this ASU in the first quarter of 2017 and applied the amendments therein to our 2017 annual goodwill impairment test.

Accounting Standards Updates Issued During the Period

In January 2017, the FASB issued ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*, which improves the guidance for determining whether a transaction involves the purchase or disposal of a business or an asset. This guidance becomes effective for fiscal years and interim periods beginning after December 15, 2017, with early adoption permitted, and prospective application required. We plan to adopt this guidance on January 1, 2018 and will apply the new guidance to applicable transactions occurring after that date.

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 update includes the following clarifications: (i) nonfinancial assets within the scope of Subtopic 610-20 may include nonfinancial assets transferred within a legal entity to a counterparty, (ii) an entity should allocate consideration to each distinct asset by applying the guidance in Topic 606 on allocating the transaction price to performance obligations and (iii) requires entities to derecognize a distinct nonfinancial asset or distinct in substance nonfinancial asset in a partial sale transaction when it (1) does not have (or ceases to have) a controlling financial interest in the legal entity that holds the asset in accordance with Subtopic 810-10 and (2) transfers control of the asset in accordance with Topic 606. This guidance is effective beginning after December 15, 2017, including interim periods within those periods and must be adopted at the same time as ASC 606. We will adopt this guidance on January 1, 2018 and are currently evaluating the impact of the adoption on our financial position, results of operations and cash flows.

In May 2017, the FASB issued ASU 2017-09, *Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting* to provide guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. Under the new guidance, modification accounting is required only if the fair value (or calculated value or intrinsic value, if such alternative method is used), the vesting conditions, or the classification of the award (equity or liability) changes as a result of the change in terms or conditions. This guidance will become effective for interim and annual periods beginning after December 31, 2017, with early adoption permitted, and prospective application required. We expect to adopt this guidance on January 1, 2018, and we do not currently anticipate that our adoption will have a material impact on our financial position, results of operations and cash flows.

Other Accounting Standards Updates

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (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 those goods or services. This ASU also requires additional disclosures. This ASU can be adopted either with a full retrospective approach or a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption and is effective for interim and annual periods beginning after December 15, 2017. We implemented a process to evaluate the impact of adopting this ASU on each type of revenue contract entered into with customers and our implementation team is in the process of determining appropriate changes to our business processes, systems and controls to support recognition and disclosure under the new standard. We have not identified any significant revenue recognition timing differences for types of revenue streams assessed to date; however, our evaluation is not complete. In addition, we are assessing the impact of changes to disclosures and expect an increase in disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. We will adopt this guidance on January 1, 2018, and currently anticipate that we will apply the modified retrospective approach.

Note 3—Net Income Per Common Unit

We calculate basic and diluted net income/(loss) per common unit by dividing net income attributable to PAA (after deducting amounts allocated to the preferred unitholders and participating securities, and for periods prior to the closing of the Simplification Transactions, the 2% general partner's interest and IDRs) 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.

Diluted net income/(loss) per common unit 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, (ii) our LTIP awards and (iii) common units that are issuable to AAP when certain AAP Management Units become earned. 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/(loss) per common unit for the three and six months ended June 30, 2017 and 2016 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 that were deemed to be dilutive 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. LTIP awards were excluded from the computation of diluted net loss per common unit for the three and six months ended June 30, 2016 as the effect was antidilutive. As none of the necessary conditions for the remaining AAP Management Units to become earned had been satisfied by June 30, 2017, no common units issuable to AAP were contemplated in the calculation of diluted net income/(loss) per common unit. See Note 16 to our Consolidated Financial Statements included in Part IV of our 2016 Annual Report on Form 10-K for a complete discussion of our LTIP awards including specific discussion regarding DERs.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Basic Net Income per Common Unit				
Net income attributable to PAA	$ 188	$ 101	632	302
Distributions to Series A preferred units [1]	(35)	(33)	(69)	(55)
Distributions to general partner [1]	—	(155)	—	(310)
Distributions to participating securities [1]	(1)	(1)	(1)	(2)
Undistributed loss allocated to general partner [1]	—	7	—	12
Other	(4)	—	(7)	—
Net income/(loss) allocated to common unitholders	$ 148	$ (81)	$ 555	$ (53)
Basic weighted average common units outstanding	725	398	708	398
Basic net income/(loss) per common unit	$ 0.21	$ (0.20)	$ 0.78	$ (0.13)
Diluted Net Income per Common Unit				
Net income attributable to PAA	$ 188	$ 101	$ 632	$ 302
Distributions to Series A preferred units [1]	(35)	(33)	(69)	(55)
Distributions to general partner [1]	—	(155)	—	(310)
Distributions to participating securities [1]	(1)	(1)	(1)	(2)
Undistributed loss allocated to general partner [1]	—	7	—	12
Other	(4)	—	(7)	—
Net income/(loss) allocated to common unitholders	$ 148	$ (81)	$ 555	$ (53)
Basic weighted average common units outstanding	725	398	708	398
Effect of dilutive securities:				
LTIP units	2	—	2	—
Diluted weighted average common units outstanding	727	398	710	398
Diluted net income/(loss) per common unit	$ 0.21	$ (0.20)	$ 0.78	$ (0.13)

(1) We calculate net income/(loss) allocated to common unitholders based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings ("undistributed loss"), if any, are allocated to the general partner, 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. The Simplification Transactions, which closed on November 15, 2016, simplified our governance structure and permanently eliminated our IDRs and the economic rights associated with our 2% general partner interest. Therefore, beginning with the distribution pertaining to the fourth quarter of 2016, our general partner is no longer entitled to receive distributions or allocations on such interests.

Note 4—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 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 or parental guarantees. As of June 30, 2017 and December 31, 2016, we had received $92 million and $89 million, respectively, of advance cash payments from third parties to mitigate credit risk. We also received $50 million and $66 million as of June 30, 2017 and December 31, 2016, 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 a majority of net-cash settled arrangements.

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, 2017 and December 31, 2016, 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, 2017 and December 31, 2016. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Note 5—Inventory, Linefill and Base Gas and Long-term Inventory

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

	June 30, 2017				December 31, 2016			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit [(1)]	Volumes	Unit of Measure	Carrying Value	Price/ Unit [(1)]
Inventory								
Crude oil	14,854	barrels	$ 675	$ 45.44	23,589	barrels	$ 1,049	$ 44.47
NGL	11,507	barrels	245	$ 21.29	13,497	barrels	242	$ 17.93
Natural gas	316	Mcf	1	$ 3.16	14,540	Mcf	32	$ 2.20
Other	N/A		15	N/A	N/A		20	N/A
Inventory subtotal			936				1,343	
Linefill and base gas								
Crude oil	12,834	barrels	741	$ 57.74	12,273	barrels	710	$ 57.85
NGL	1,625	barrels	45	$ 27.69	1,660	barrels	45	$ 27.11
Natural gas	24,976	Mcf	108	$ 4.32	30,812	Mcf	141	$ 4.58
Linefill and base gas subtotal			894				896	
Long-term inventory								
Crude oil	1,922	barrels	77	$ 40.06	3,279	barrels	163	$ 49.71
NGL	1,863	barrels	40	$ 21.47	1,418	barrels	30	$ 21.16
Long-term inventory subtotal			117				193	
Total			$ 1,947				$ 2,432	

(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" in our accompanying Condensed Consolidated Statements of Operations. See Note 10 for discussion of our derivative and risk management activities. We recorded an inventory valuation adjustment of $3 million during the six months ended June 30, 2016.

Note 6—Acquisitions and Dispositions

Acquisitions

The following acquisitions were accounted for using the acquisition method of accounting and the determination of the fair value of the assets and liabilities acquired has been estimated in accordance with the applicable accounting guidance.

Alpha Crude Connector Acquisition

On February 14, 2017, we acquired all of the issued and outstanding membership interests in Alpha Holding Company, LLC for cash consideration of approximately $1.217 billion, subject to working capital and other adjustments (the "ACC Acquisition"). The ACC Acquisition was initially funded through borrowings under our senior unsecured revolving credit facility. Such borrowings were subsequently repaid with proceeds from our March 2017 issuance of common units to AAP pursuant to the Omnibus Agreement and in connection with a PAGP underwritten equity offering. See Note 9 for additional information.

Upon completion of the ACC Acquisition, we became the owner of a crude oil gathering system known as "Alpha Crude Connector" (the "ACC System") located in the Northern Delaware Basin in Southeastern New Mexico and West Texas. The ACC System comprises 515 miles of gathering and transmission lines and five market interconnects, including to our Basin Pipeline at Wink. We intend to make additional interconnects to our existing Northern Delaware Basin systems as well as additional enhancements intended to increase the ACC System capacity to approximately 350,000 barrels per day, depending on the level of volume at each delivery point. The ACC System is supported by acreage dedications covering approximately 315,000 gross acres, and include a significant acreage dedication from one of the largest producers in the region. The ACC System complements our other Permian Basin assets and enhances the services available to the producers in the Northern Delaware Basin.

The determination of the acquisition-date fair value of the assets acquired and liabilities assumed is preliminary. We expect to finalize our fair value determination in 2017. The following table reflects the preliminary fair value determination (in millions):

Identifiable assets acquired and liabilities assumed:	Estimated Useful Lives (Years)	Recognized amount
Property and equipment	3 - 70	$ 299
Intangible assets	20	646
Goodwill	N/A	271
Other assets and liabilities, net (including $4 million of cash acquired)	N/A	1
		$ 1,217

Intangible assets are included in “Other long-term assets, net” on our Condensed Consolidated Balance Sheets. The preliminary determination of fair value to intangible assets above is comprised of five acreage dedication contracts and associated customer relationships that will be amortized over a remaining weighted average useful life of approximately 20 years. The value assigned to such intangible assets will be amortized to earnings using methods that closely resemble the pattern in which the economic benefits will be consumed. Amortization expense was approximately $4 million for the period from February 14, 2017 through June 30, 2017, and the future amortization expense is estimated as follows for the next five years (in millions):

Remainder of 2017	$	6
2018	$	25
2019	$	34
2020	$	42
2021	$	48

Goodwill is an intangible asset representing the future economic benefits expected to be derived from other assets acquired that are not individually identified and separately recognized. The goodwill arising from the ACC Acquisition, which is tax deductible, represents the anticipated opportunities to generate future cash flows from undedicated acreage and the synergies created between the ACC System and our existing assets. The assets acquired in the ACC Acquisition, as well as the associated goodwill, are primarily included in our Transportation segment.

During the three and six months ended June 30, 2017, we incurred approximately $1 million and $6 million of acquisition-related costs associated with the ACC Acquisition. Such costs are reflected as a component of general and administrative expenses in our Condensed Consolidated Statements of Operations.

Pro forma financial information assuming the ACC Acquisition had occurred as of the beginning of the calendar year prior to the year of acquisition, as well as the revenues and earnings generated during the period since the acquisition date, were not material for disclosure purposes.

Other Acquisitions

In February 2017, we acquired a propane marine terminal for cash consideration of approximately $41 million. The assets acquired are included in our Facilities segment. We did not recognize any goodwill related to this acquisition.

Investment Acquisition

On April 3, 2017, we and an affiliate of Noble Midstream Partners LP (“Noble”) completed the acquisition of Advantage Pipeline, L.L.C. (“Advantage”) for a purchase price of $133 million through a newly formed 50/50 joint venture (the “Advantage Joint Venture”). For our 50% share ($66.5 million), we contributed approximately 1.3 million common units with a value of approximately $40 million and approximately $26 million in cash. We account for our interest in the Advantage Joint Venture under the equity method of accounting.

Advantage owns a 70-mile, 16-inch crude oil pipeline located in the southern Delaware Basin (the “Advantage Pipeline”). Noble will serve as operator and will construct a pipeline to deliver crude oil to the Advantage Pipeline from its central gathering facility in the southern Delaware Basin. We will construct a pipeline to connect our Wolfbone Ranch facility to the Advantage Pipeline near Highway 285 in Reeves County, Texas. The connections are estimated to be completed in 2017. The Advantage Pipeline is contractually supported by a third-party acreage dedication and a volume commitment from our wholly-owned marketing subsidiary.

Dispositions, Divestitures and Assets Held for Sale

During the six months ended June 30, 2017, we sold certain non-core assets for proceeds of approximately $389 million. These sales primarily included (i) our Bluewater natural gas storage facility located in Michigan, (ii) a non-core pipeline segment located in the Midwestern United States and (iii) a 40% undivided interest in a segment of our Red River Pipeline extending from Cushing, Oklahoma to the Hewitt Station near Ardmore, Oklahoma (the “Hewitt Segment”) for our net book value. We retained a 60% undivided interest in the Hewitt Segment and a 100% interest in the remaining portion of the Red River Pipeline that extends from Ardmore to Longview, Texas.

We recognized a net gain of $36 million during the six months ended June 30, 2017 related to the sale of the non-core pipeline segment, including the write-off of a portion of the remaining book value. In addition, during the six months ended June 30, 2017, we recognized a loss of $35 million related to assets that were classified as held for sale prior to the closing of the transactions. Such gains and losses are included in “Depreciation and amortization” on our Condensed Consolidated Statements of Operations.

As of June 30, 2017, we classified approximately $275 million of Facilities segment assets, primarily property and equipment, as held for sale on our Condensed Consolidated Balance Sheet (in “Other current assets”) related to definitive agreements to sell such assets. We expect these transactions to close during 2017.

During the third quarter of 2017, we entered into a definitive agreement to sell our interests in certain non-core pipelines in the Rocky Mountains for proceeds of approximately $250 million.

Note 7—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, 2016	$ 806	$ 1,034	$ 504	$ 2,344
Acquisitions [(1)]	271	—	—	271
Foreign currency translation adjustments	8	4	2	14
Dispositions and reclassifications to assets held for sale	—	(33)	—	(33)
Balance at June 30, 2017	$ 1,085	$ 1,005	$ 506	$ 2,596

(1) Goodwill is recorded at the acquisition date based on a preliminary fair value determination. This preliminary goodwill balance may be adjusted when the fair value determination is finalized.

We completed our goodwill impairment test as of June 30, 2017 using a qualitative assessment. We determined that it was more likely than not that the fair value of each reporting unit was greater than its respective book value; therefore, additional impairment testing was not necessary and goodwill was not considered impaired.

Note 8—Debt

Debt consisted of the following (in millions):

	June 30, 2017	December 31, 2016
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 2.0% and 1.6%, respectively [(1)]	$ 677	$ 563
Senior secured hedged inventory facility, bearing a weighted-average interest rate of 2.3% and 1.8%, respectively [(1)]	300	750
Senior notes:		
6.13% senior notes due January 2017	—	400
Other	137	2
Total short-term debt [(2)]	1,114	1,715
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $72 and $76, respectively [(3)]	9,878	9,874
Commercial paper notes, bearing a weighted-average interest rate of 2.0% and 1.6%, respectively [(3)]	159	247
Other	3	3
Total long-term debt	10,040	10,124
Total debt [(4)]	$ 11,154	$ 11,839

(1) We classified these commercial paper notes and credit facility borrowings as short-term as of June 30, 2017 and December 31, 2016, 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, 2017 and December 31, 2016, balance includes borrowings of $12 million and $410 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, 2017, we have classified our $600 million, 6.50% senior notes due May 2018 as long-term and as of June 30, 2017 and December 31, 2016, we have classified a portion of our commercial paper notes as long-term based on our ability and intent to refinance such amounts on a long-term basis.

(4) Our fixed-rate senior notes (including current maturities) had a face value of approximately $9.9 billion and $10.3 billion as of June 30, 2017 and December 31, 2016, respectively. We estimated the aggregate fair value of these notes as of June 30, 2017 and December 31, 2016 to be approximately $10.1 billion and $10.4 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.

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the six months ended June 30, 2017 and 2016 were approximately $36.8 billion and $23.0 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $37.2 billion and $23.6 billion for the six months ended June 30, 2017 and 2016, 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 of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs, derivative transactions and construction activities. At June 30, 2017 and December 31, 2016, we had outstanding letters of credit of $105 million and $73 million, respectively.

Senior Notes Repayments

Our $400 million, 6.13% senior notes were repaid in January 2017. We utilized cash on hand and available capacity under our commercial paper program and credit facilities to repay these notes.

Note 9—Partners' Capital and Distributions

Units Outstanding

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

	Limited Partners	
	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 (Note 6)	—	1,252,269
Issuances of common units under LTIP	—	130,154
Outstanding at June 30, 2017	66,990,153	724,696,735

	Limited Partners	
	Preferred Units	Common Units
Outstanding at December 31, 2015	—	397,727,624
Sale of Series A preferred units	61,030,127	—
Issuance of Series A preferred units in connection with in-kind distribution	858,439	—
Issuance of common units under LTIP	—	9,104
Outstanding at June 30, 2016	61,888,566	397,736,728

Sales of Common Units

The following table summarizes our sales of common units during the six months ended June 30, 2017 (net proceeds in millions):

Type of Offering	Common Units Issued		Net Proceeds [(1)]	
Continuous Offering Program	4,033,567		$ 129	[(2)]
Omnibus Agreement [(3)]	50,086,326	[(4)]	1,535	
	54,119,893		**$ 1,664**	

(1) Amounts are net of costs associated with the offerings.

(2) We pay commissions to our sales agents in connection with common units issuances under our Continuous Offering Program. We paid $1 million of such commissions during the six months ended June 30, 2017.

(3) Pursuant to the Omnibus Agreement entered into by the Plains Entities in connection with the Simplification Transactions, PAGP has agreed to use the net proceeds from any public or private offering and sale of Class A shares, after deducting the sales agents' commissions and offering expenses, to purchase from AAP a number of AAP units equal to the number of Class A shares sold in such offering at a price equal to the net proceeds from such offering. The Omnibus Agreement also provides that immediately following such purchase and sale, AAP will use the net proceeds it receives from such sale of AAP units to purchase from us an equivalent number of our common units.

(4) Includes (i) approximately 1.8 million common units issued to AAP in connection with PAGP's issuance of Class A shares under its Continuous Offering Program and (ii) 48.3 million common units issued to AAP in connection with PAGP's March 2017 underwritten offering.

Distributions

Cash Distributions. The following table details the distributions paid in cash during or pertaining to the first six months of 2017 (in millions, except per unit data):

	Distributions			
	Common Unitholders			
Distribution Payment Date	Public	AAP	Total Cash Distribution	Cash Distribution per Common Unit
August 14, 2017 [(1)]	$ 240	$ 159	$ 399	$ 0.55
May 15, 2017	$ 240	$ 159	$ 399	$ 0.55
February 14, 2017	$ 237	$ 134	$ 371	$ 0.55

(1) Payable to unitholders of record at the close of business on July 31, 2017 for the period April 1, 2017 through June 30, 2017.

On August 7, 2017, we announced that we were engaged in discussions with our Board of Directors regarding a reassessment of our approach to distributions, with a focus on resetting PAA's common unit distribution to a level supported by the distributable cash flow from our fee-based Transportation and Facilities segments. As of such date, no final decisions had been made regarding such potential change, but we indicated that we intended to complete our reassessment and finalize any changes over the course of the ensuing sixty day period.

In-Kind Distributions. On February 14, 2017, we issued 1,287,773 Series A preferred units in lieu of a cash distribution of $34 million on our Series A preferred units outstanding as of the record date for such distribution. On May 15, 2017, we issued 1,313,527 Series A preferred units in lieu of a cash distribution of $34 million on our Series A preferred units outstanding as of the record date for such distribution.

On August 14, 2017, we will issue 1,339,796 Series A preferred units in lieu of a cash distribution of $35 million on our Series A preferred units outstanding as of July 31, 2017, the record date for such distribution. Since the August 14, 2017 Series A preferred unit distribution was declared as payment-in-kind, this distribution payable was accrued to partners’ capital as of June 30, 2017 and thus had no net impact on the Series A preferred unitholders’ capital account.

Note 10—Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on hydrocarbon commodity (referred to herein as “commodity”) price changes. We use various derivative instruments to manage our exposure to (i) commodity price risk, as well as to optimize our profits, (ii) interest rate risk and (iii) currency exchange rate risk. Our commodity price risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our derivative positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate and currency exchange rate risk management policies and procedures are designed to monitor our derivative positions and ensure that those positions are consistent with our objectives and approved strategies. When we apply hedge accounting, our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument’s effectiveness will be assessed. 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.

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, 2017, net derivative positions related to these activities included:

- A net long position of 1.4 million barrels associated with our crude oil purchases, which was unwound ratably during July 2017 to match monthly average pricing.
- A net short time spread position of 2.5 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through October 2018.
- A crude oil grade basis position of 37.5 million barrels through December 2019. These derivatives allow us to lock in grade basis differentials.
- A net short position of 16.7 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 that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. 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, 2017, our PLA hedges included a long call option position of 0.7 million barrels through December 2018.

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, 2017, we had a long natural gas position of 56.6 Bcf which hedges our natural gas processing and operational needs through December 2020. We also had a short propane position of 8.5 million barrels through December 2018, a short butane position of 2.6 million barrels through December 2018 and a short WTI position of 0.7 million barrels through December 2018. In addition, we had a long power position of 0.5 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 risk 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 payments associated with the underlying debt.

The following table summarizes the terms of our outstanding interest derivatives as of June 30, 2017 (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	16 forward starting swaps (30-year)	$ 400	6/15/2018	2.86%	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/14/2019	2.83%	Cash flow hedge

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated 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, 2017, our outstanding foreign currency derivatives include derivatives we use to hedge currency exchange risk (i) associated with USD-denominated commodity purchases and sales in Canada and (ii) created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

The following table summarizes our open forward exchange contracts as of June 30, 2017 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2017	$ 154	$ 205	$1.00 - $1.33
Forward exchange contracts that exchange USD for CAD:				
	2017	$ 346	$ 457	$1.00 - $1.32

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. At June 30, 2017 and December 31, 2016, the fair value of this embedded derivative was a liability of approximately $35 million and $32 million, respectively. We recognized a gain of approximately $2 million during the three months ended June 30, 2017 and a net loss of approximately $2 million during the six months ended June 30, 2017. We recognized a gain of $25 million during the three and six months ended June 30, 2016. See Note 11 to our Consolidated Financial Statements included in Part IV of our 2016 Annual Report on Form 10-K for additional information regarding the 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.

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

	Three Months Ended June 30, 2017			Three Months Ended June 30, 2016		
Location of Gain/(Loss)	Derivatives in Hedging Relationships (1)	Derivatives Not Designated as a Hedge	Total	Derivatives in Hedging Relationships (1)	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives						
Supply and Logistics segment revenues	$ —	$ 99	$ 99	$ (1)	$ (159)	$ (160)
Transportation segment revenues	—	—	—	—	1	1
Field operating costs	—	(1)	(1)	—	2	2
Depreciation and amortization	(3)	—	(3)	—	—	—
Interest Rate Derivatives						
Interest expense, net	(4)	—	(4)	(4)	—	(4)
Foreign Currency Derivatives						
Supply and Logistics segment revenues	—	—	—	—	(1)	(1)
Preferred Distribution Rate Reset Option						
Other income/(expense), net	—	2	2	—	25	25
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (7)	$ 100	$ 93	$ (5)	$ (132)	$ (137)

Location of Gain/(Loss)	Six Months Ended June 30, 2017 Derivatives in Hedging Relationships [(1)]	Six Months Ended June 30, 2017 Derivatives Not Designated as a Hedge	Six Months Ended June 30, 2017 Total	Six Months Ended June 30, 2016 Derivatives in Hedging Relationships [(1)]	Six Months Ended June 30, 2016 Derivatives Not Designated as a Hedge	Six Months Ended June 30, 2016 Total
Commodity Derivatives						
Supply and Logistics segment revenues	$ —	$ 195	$ 195	$ —	$ (128)	$ (128)
Transportation segment revenues	—	—	—	—	3	3
Field operating costs	—	(4)	(4)	—	—	—
Depreciation and amortization	(3)	—	(3)	—	—	—
Interest Rate Derivatives						
Interest expense, net	(6)	—	(6)	(6)	—	(6)
Foreign Currency Derivatives						
Supply and Logistics segment revenues	—	2	2	—	5	5
Preferred Distribution Rate Reset Option						
Other income/(expense), net	—	(2)	(2)	—	25	25
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (9)	$ 191	$ 182	$ (6)	$ (95)	$ (101)

(1) During the three and six months ended June 30, 2017 we reclassified a loss of approximately $2 million to Interest expense, net due to anticipated hedged transactions being probable of not occurring. During the three and six months ended June 30, 2016 we reclassified losses of approximately $2 million and $2 million to Supply and Logistics segment revenues and Interest expense, net, respectively, due to anticipated hedged transactions being probable of not occurring.

The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of June 30, 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	$ (26)
			Other long-term liabilities and deferred credits	(8)
Total derivatives designated as hedging instruments		$ 2		$ (34)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 111	Other current assets	$ (71)
	Other long-term assets, net	7	Other long-term assets, net	(1)
	Other long-term liabilities and deferred credits	3	Other current liabilities	(14)
			Other long-term liabilities and deferred credits	(9)
Foreign currency derivatives	Other current assets	6	Other current assets	(3)
	Other current liabilities	1	Other current liabilities	(1)
Preferred Distribution Rate Reset Option		—	Other long-term liabilities and deferred credits	(35)
Total derivatives not designated as hedging instruments		$ 128		$ (134)
Total derivatives		$ 130		$ (168)

The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of December 31, 2016 (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	$ (23)
			Other long-term liabilities and deferred credits	(27)
Total derivatives designated as hedging instruments		$ —		$ (50)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 101	Other current assets	$ (344)
	Other long-term assets, net	2	Other long-term assets, net	(1)
	Other long-term liabilities and deferred credits	2	Other current liabilities	(14)
			Other long-term liabilities and deferred credits	(34)
Foreign currency derivatives	Other current liabilities	3	Other current liabilities	(6)
Preferred Distribution Rate Reset Option		—	Other long-term liabilities and deferred credits	(32)
Total derivatives not designated as hedging instruments		$ 108		$ (431)
Total derivatives		$ 108		$ (481)

Our derivative transactions are governed through ISDA (International Swaps and Derivatives Association) master agreements and clearing brokerage agreements. These agreements include stipulations regarding the right of set off in the event that we or our counterparty default on performance obligations. If a default were to occur, both parties have the right to net amounts payable and receivable into a single net settlement between parties.

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

	June 30, 2017	December 31, 2016
Initial margin	$ 55	$ 119
Variation margin posted/(returned)	(43)	291
Net broker receivable/(payable)	$ 12	$ 410

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, 2017		December 31, 2016	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 130	$ (168)	$ 108	$ (481)
Netting adjustment	(81)	81	(350)	350
Cash collateral paid/(received)	12	—	410	—
Net position - asset/(liability)	$ 61	$ (87)	$ 168	$ (131)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 55	$ —	$ 167	$ —
Other long-term assets, net	6	—	1	—
Other current liabilities	—	(38)	—	(40)
Other long-term liabilities and deferred credits	—	(49)	—	(91)
	$ 61	$ (87)	$ 168	$ (131)

As of June 30, 2017, there was a net loss of $231 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 transaction or (ii) interest expense accruals associated with underlying debt instruments. Of the total net loss deferred in AOCI at June 30, 2017, we expect to reclassify a net loss of $8 million to earnings in the next twelve months. The remaining deferred loss of $223 million is expected to be reclassified to earnings through 2049. A portion of these amounts is based on market prices as of June 30, 2017; 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 deferred gain/(loss) recognized in AOCI for derivatives (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Interest rate derivatives, net	$ (19)	$ (68)	$ (12)	$ (158)

At June 30, 2017 and December 31, 2016, 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, 2017				Fair Value as of December 31, 2016			
Recurring Fair Value Measures (1)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	$ 7	$ 14	$ 5	$ 26	$ (113)	$ (171)	$ (4)	$ (288)
Interest rate derivatives	—	(32)	—	(32)	—	(50)	—	(50)
Foreign currency derivatives	—	3	—	3	—	(3)	—	(3)
Preferred Distribution Rate Reset Option	—	—	(35)	(35)	—	—	(32)	(32)
Total net derivative asset/(liability)	$ 7	$ (15)	$ (30)	$ (38)	$ (113)	$ (224)	$ (36)	$ (373)

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

Level 1

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

Level 2

Level 2 of the fair value hierarchy includes exchange-cleared commodity derivatives and over-the-counter commodity, interest rate and foreign currency derivatives that are traded in 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 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 is based on a valuation model utilizing timing estimates, which involve management judgment. Significant changes in timing could result in a material change in fair value to our physical 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.

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 increase or decrease in the value of 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 as “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,	
	2017	**2016**	**2017**	**2016**
Beginning Balance	$ (36)	$ (59)	$ (36)	$ 11
Net gains/(losses) for the period included in earnings	3	23	(1)	23
Settlements	—	—	3	(9)
Derivatives entered into during the period	3	1	4	(60)
Ending Balance	$ (30)	$ (35)	$ (30)	$ (35)
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	$ 6	$ 24	$ 3	$ 24

Note 11—Related Party Transactions

See Note 15 to our Consolidated Financial Statements included in Part IV of our 2016 Annual Report on Form 10-K for a complete discussion of our related party transactions.

Omnibus Agreement

Pursuant to the Omnibus Agreement entered into by the Plains Entities in connection with the Simplification Transactions, we issued approximately 1.8 million units to AAP in connection with PAGP's issuance of Class A shares under its Continuous Offering Program and 48.3 million units to AAP in connection with PAGP's March 2017 underwritten offering. See Note 9 for additional information.

Transactions with Oxy

As of June 30, 2017, Oxy had a representative on the board of directors of PAGP GP and owned approximately 10% of the limited partner interests in AAP. During the three and six months ended June 30, 2017 and 2016, 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,	
	2017	2016	2017	2016
Revenues	$ 220	$ 142	$ 453	$ 254
Purchases and related costs [1]	$ (61)	$ (4)	$ (101)	$ (50)

[1] Purchases and related costs include crude oil buy/sell transactions that are accounted for as inventory exchanges and are presented net 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, 2017	December 31, 2016
Trade accounts receivable and other receivables	$ 804	$ 789
Accounts payable	$ 748	$ 836

Note 12—Commitments and Contingencies

Loss Contingencies — General

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

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

Legal Proceedings — General

In the ordinary course of business, we are involved in various legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully protect us from losses arising from current or future legal proceedings.

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

Environmental — General

Although over the course of the last several years we have made significant investments in our maintenance and integrity programs, and have hired additional personnel in those areas, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline, rail, storage and other facility operations. These releases can result from accidents or from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Damages and liabilities associated with any such releases from our existing or future assets could be significant and could have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

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

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

At June 30, 2017, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident, as discussed further below) totaled $150 million, of which $64 million was classified as short-term and $86 million was classified as long-term. At December 31, 2016, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident) totaled $147 million, of which $61 million was classified as short-term and $86 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, 2017, we had recorded receivables totaling $44 million for amounts probable of recovery under insurance and from third parties under indemnification agreements, of which $26 million was reflected in “Trade accounts receivable and other receivables, net” and $18 million was reflected in “Other long-term assets, net” on our Condensed Consolidated Balance Sheet. At December 31, 2016, we had recorded $56 million of such receivables, of which $39 million was reflected in “Trade accounts receivable and other receivables, net” and $17 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 includes the United States Coast Guard, the EPA, the California Office of Spill Prevention and Response and the Santa Barbara Office of Emergency Management, was established for the response effort. Clean-up and remediation operations with respect to impacted shoreline and other areas has been determined by the Unified Command to be complete, and the Unified Command has been dissolved. Our estimate of the amount of oil spilled, based on relevant facts, data and information, is approximately 2,934 barrels; of this amount, we estimate that 598 barrels reached the Pacific Ocean.

As a result of the Line 901 incident, several governmental agencies and regulators initiated investigations into the Line 901 incident, various claims have been made against us and a number of lawsuits have been filed against us. We may be subject to additional claims, investigations and lawsuits, which could materially impact the liabilities and costs we currently expect to incur as a result of the Line 901 incident. Set forth below is a brief summary of actions and matters that are currently pending:

On May 21, 2015, we received a corrective action order from the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA"), the governmental agency with jurisdiction over the operation of Line 901 as well as over a second stretch of pipeline extending from Gaviota Pump Station in Santa Barbara County to Emidio Pump Station in Kern County, California (Line 903), requiring us to shut down, purge, review, remediate and test Line 901. The corrective action order was subsequently amended on June 3, 2015; November 13, 2015; and June 16, 2016 to require us to take additional corrective actions with respect to both Lines 901 and 903 (as amended, the "CAO"). Among other requirements, the CAO also obligates 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 imposes a pressure restriction on the section of Line 903 between Pentland Pump Station and Emidio Pump Station and requires 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 any such civil or criminal charges with respect to the Line 901 release, their investigation is still open and we may have fines or penalties imposed upon us, or civil or criminal charges brought against us, in the future.

On September 11, 2015, we received a Notice of Probable Violation and Proposed Compliance Order from PHMSA arising out of its inspection of Lines 901 and 903 in August, September and October of 2013 (the "2013 Audit NOPV"). The 2013 Audit NOPV alleges that the Partnership committed probable violations of various federal pipeline safety regulations by failing to document, or inadequately documenting, certain activities. On October 12, 2015, the Partnership filed a response to the 2013 Audit NOPV. To date, PHMSA has not issued a final order with respect to the 2013 Audit NOPV, nor has it assessed any fines or penalties with respect thereto; however, we cannot provide any assurances that any such fines or penalties will not be assessed against us.

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 indictment included a total of 46 counts, 36 of which were misdemeanor charges relating to wildlife allegedly taken as a result of the accidental release. The remaining 10 counts (currently three felony and seven misdemeanor charges) relate to the release of crude oil or reporting of the release. PAA believes that the criminal 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. PAA intends to continue to vigorously defend itself against the charges. On July 28, 2016, at an arraignment hearing held in California Superior Court in Santa Barbara County, PAA pled not guilty to all counts.

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 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 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, including potential classes such as commercial fishermen who landed fish in certain specified fishing blocks in the waters adjacent to Santa Barbara County or from persons or businesses who resold commercial seafood landed in such areas, certain owners of oceanfront and/or beachfront property on the Pacific Coast of California, and other classes of individuals and businesses that were allegedly impacted by the release. To date, only the commercial fisherman and seafood reseller class has been certified by the court. 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 have refiled their complaint and we are opposing their claims. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we are indemnifying and funding the defense costs of our officers and directors in connection with these lawsuits; we are also indemnifying and funding 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. 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. The other remaining lawsuit was filed in State District Court in Harris County, Texas. In general, these 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 two remaining lawsuits 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 these lawsuits 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 these lawsuits.

We have also had two lawsuits filed against us wherein the respective plaintiffs seek to compel the production of certain books and records that purportedly relate to the Line 901 incident, our alleged failure to comply with certain regulations and other matters. These lawsuits have been consolidated into a single proceeding in the Chancery Court for the State of Delaware.

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, 2017, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $300 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 accrued such estimate of aggregate total costs to "Field operating costs" primarily during 2015. 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, 2017, we had a remaining undiscounted gross liability of $78 million related to this event, of which approximately $53 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, 2017, we had collected, subject to customary reservations, $166 million out of the approximate $205 million of release costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of June 30, 2017, we have recognized a receivable of approximately $39 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 $21 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.

In the Matter of Bakersfield Crude Terminal LLC et al. On April 30, 2015, the EPA issued a Finding and Notice of Violation ("NOV") to Bakersfield Crude Terminal LLC, our subsidiary, for alleged violations of the Clean Air Act, as amended. The NOV, which cites 10 separate rule violations, questions the validity of construction and operating permits issued to our Bakersfield rail unloading facility in 2012 and 2014 by the San Joaquin Valley Air Pollution Control District (the "SJV District"). We believe we fully complied with all applicable regulatory requirements and that the permits issued to us by the SJV District are valid. To date, no fines or penalties have been assessed in this matter; however, it is possible that fines and penalties could be assessed in the future.

Mesa to Basin Pipeline. On January 6, 2016, PHMSA issued a Notice of Probable Violation and Proposed Civil Penalty relating to an approximate 500 barrel release of crude oil that took place on January 1, 2015 on our Mesa to Basin 12" pipeline in Midland, Texas. PHMSA conducted an accident investigation and reviewed documentation related to the incident, and concluded that we had committed probable violations of certain pipeline safety regulations. In the Notice, PHMSA maintains that we failed to carry out our written damage prevention program and to follow our pipeline excavation/ditching and backfill procedures on four separate occasions, and that such failures resulted in outside force damage that led to the January 1, 2015 release. In early March 2017, PHMSA issued a final order that concluded that we followed our pipeline excavation/ditching and backfill procedures, but maintained that we failed to carry out our written damage prevention program and imposed a civil penalty of $184,300. We have since paid such penalty in full and do not anticipate any further action by PHMSA with respect to this matter.

Note 13—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 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 or 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 of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets.

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

Three Months Ended June 30, 2017	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment [(1)]	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

Three Months Ended June 30, 2016	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment [1]	Total
Revenues:					
External customers [1]	$ 244	$ 132	$ 4,648	$ (74)	$ 4,950
Intersegment [2]	159	138	4	74	375
Total revenues of reportable segments	$ 403	$ 270	$ 4,652	$ —	$ 5,325
Equity earnings in unconsolidated entities	$ 40	$ —	$ —		$ 40
Segment adjusted EBITDA	$ 274	$ 161	$ 39		$ 474
Maintenance capital	$ 23	$ 9	$ 3		$ 35

Six Months Ended June 30, 2017	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment [1]	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

Six Months Ended June 30, 2016	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment [1]	Total
Revenues:					
External customers [1]	$ 484	$ 270	$ 8,467	$ (161)	$ 9,060
Intersegment [2]	303	265	6	161	735
Total revenues of reportable segments	$ 787	$ 535	$ 8,473	$ —	$ 9,795
Equity earnings in unconsolidated entities	$ 87	$ —	$ —		$ 87
Segment adjusted EBITDA	$ 555	$ 327	$ 224		$ 1,106
Maintenance capital	$ 57	$ 18	$ 6		$ 81

(1) Transportation revenues from external customers include inventory exchanges that are substantially similar to tariff-like arrangements with our customers. Under these arrangements, our Supply and Logistics segment has transacted the inventory exchange and serves as the shipper on our pipeline systems. See Note 2 to our Consolidated Financial Statements included in Part IV of our 2016 Annual Report on Form 10-K for a discussion of our related accounting policy. We have included an estimate of the revenues from these inventory exchanges in our Transportation segment revenue 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 sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market at the time the agreement is executed or renegotiated.

Segment Adjusted EBITDA Reconciliation

The following table reconciles segment adjusted EBITDA to net income attributable to PAA (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	**2016**	**2017**	**2016**
Segment adjusted EBITDA	$ 450	$ 474	$ 962	$ 1,106
Adjustments [1]:				
Depreciation and amortization of unconsolidated entities [2]	(4)	(13)	(18)	(25)
Gains/(losses) from derivative activities net of inventory valuation adjustments [3]	13	(119)	302	(242)
Long-term inventory costing adjustments [4]	(7)	67	(14)	44
Deficiencies under minimum volume commitments, net [5]	14	(8)	3	(34)
Equity-indexed compensation expense [6]	(9)	(11)	(12)	(15)
Net gain/(loss) on foreign currency revaluation [7]	10	—	14	(1)
Line 901 incident [8]	(12)	—	(12)	—
Significant acquisition-related expenses [9]	(1)	—	(6)	—
Depreciation and amortization	(129)	(204)	(250)	(319)
Interest expense, net	(127)	(114)	(256)	(227)
Other income/(expense), net	1	25	(4)	30
Income before tax	199	97	709	317
Income tax benefit/(expense)	(10)	5	(76)	(13)
Net income	189	102	633	304
Net income attributable to noncontrolling interests	(1)	(1)	(1)	(2)
Net income attributable to PAA	$ 188	$ 101	$ 632	$ 302

(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 or 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 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 12 for additional information regarding the Line 901 incident.

(9) Includes acquisition-related expenses associated with the ACC Acquisition. See Note 6 for additional discussion. An adjustment for these non-recurring expenses is included in the calculation of segment adjusted EBITDA for the three and six months ended June 30, 2017 as our CODM does not view such expenses as integral to understanding our core segment operating performance. Acquisition-related expenses for the 2016 period were not significant to segment adjusted EBITDA.

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 2016 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
- Outlook
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates
- Forward-Looking Statements

Executive Summary

Company Overview

We own and operate midstream energy infrastructure and provide logistics services for crude oil, NGL, natural gas and refined products. 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 2017, we recognized net income attributable to PAA of $632 million as compared to net income attributable to PAA of $302 million recognized during the first six months of 2016. Our financial results for the comparative periods were impacted by:

- The favorable impact of gains on certain derivative instruments and contributions from our recently completed acquisitions and capital expansion projects, partially offset by less favorable crude oil and NGL market conditions and margin compression caused by continued intense competition;

- Higher interest expense primarily related to financing activities associated with our capital investments;

- Lower depreciation and amortization expense primarily due to impairment losses recognized during the 2016 period;

- The mark-to-market of our Preferred Distribution Rate Reset Option, resulting in a loss in the current period compared to a gain in the prior period; and

- Higher income tax expense primarily due to higher year-over-year income as impacted by fluctuations in derivative mark-to-market valuations in our Canadian operations.

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

We invested $614 million in midstream infrastructure projects during the six months ended June 30, 2017, with a targeted expansion capital plan for the full year of 2017 of approximately $950 million. Additionally, in February 2017, we acquired a crude oil gathering system located in the Northern Delaware Basin for approximately $1.217 billion and a marine propane terminal for $41 million. In April 2017, we completed the formation of a 50/50 joint venture, which subsequently acquired a crude oil pipeline located in the Southern Delaware Basin for $133 million. For our 50% share ($66.5 million), we contributed approximately 1.3 million common units and approximately $26 million in cash. To fund such capital activities, we sold approximately 54.1 million common units for net proceeds of approximately $1.7 billion. We also continued to advance our strategic divestiture program, completing three non-core asset sales during the first half of 2017 for cash proceeds of approximately $389 million. In addition, we entered into a definitive agreement in 2016 for an approximately $290 million sale of non-core assets for which regulatory approval is still pending. During the third quarter of 2017, we also entered into an additional definitive agreement to sell our interests in certain non-core pipelines in the Rocky Mountains for proceeds of approximately $250 million, and we are in various stages of discussion or advanced discussion and negotiations regarding additional sales of non-core assets or partial sales of assets to strategic partners for potential additional proceeds of approximately $150 million to $350 million.

We paid approximately $770 million of cash distributions to our common unitholders during the six months ended June 30, 2017, and we declared a quarterly distribution of $0.55 per common unit to be paid on August 14, 2017.

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,	
	2017	**2016**
Acquisition capital [(1)] [(2)]	$ 1,325	$ 85
Expansion capital [(1)] [(3)]	614	709
Maintenance capital [(3)]	131	81
	$ 2,070	$ 875

(1) Acquisition capital for the first six months of 2017 primarily relates to the ACC Acquisition. See Note 6 to our Condensed Consolidated Financial Statements for further discussion regarding our acquisition activities.

(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 2017 and the estimated cost for the year ending December 31, 2017 (in millions):

Projects	2017
Diamond Pipeline [(1)]	$300
Permian Basin Area Systems	180
Fort Saskatchewan Facility Projects	90
STACK Projects [(1)]	55
Cushing Terminal Expansions	35
St. James Terminal Projects	20
Other Projects	270
Total Projected 2017 Expansion Capital Expenditures	$950

(1) Represents contributions related to our 50% investment interest.

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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	
	2017	2016	$	%	2017	2016	$	%
Transportation segment adjusted EBITDA [1]	$ 298	$ 274	$ 24	9 %	$ 571	$ 555	$ 16	3 %
Facilities segment adjusted EBITDA [1]	180	161	19	12 %	368	327	41	13 %
Supply and Logistics segment adjusted EBITDA [1]	(28)	39	(67)	(172)%	23	224	(201)	(90)%
Adjustments:								
Depreciation and amortization of unconsolidated entities	(4)	(13)	9	69 %	(18)	(25)	7	28 %
Selected items impacting comparability - segment adjusted EBITDA	8	(71)	79	**	275	(248)	523	**
Depreciation and amortization	(129)	(204)	75	37 %	(250)	(319)	69	22 %
Interest expense, net	(127)	(114)	(13)	(11)%	(256)	(227)	(29)	(13)%
Other income/(expense), net	1	25	(24)	(96)%	(4)	30	(34)	(113)%
Income tax benefit/(expense)	(10)	5	(15)	(300)%	(76)	(13)	(63)	(485)%
Net income	189	102	87	85 %	633	304	329	108 %
Net income attributable to noncontrolling interests	(1)	(1)	—	— %	(1)	(2)	1	50 %
Net income attributable to PAA	$ 188	$ 101	$ 87	86 %	$ 632	$ 302	$ 330	109 %
Basic net income/(loss) per common unit	$ 0.21	$ (0.20)	$ 0.41	**	$ 0.78	$ (0.13)	$ 0.91	**
Diluted net income/(loss) per common unit	$ 0.21	$ (0.20)	$ 0.41	**	$ 0.78	$ (0.13)	$ 0.91	**
Basic weighted average common units outstanding	725	398	327	**	708	398	310	**
Diluted weighted average common units outstanding	727	398	329	**	710	398	312	**

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

(1) Segment adjusted EBITDA is the measure of segment performance that is utilized by our Chief Operating Decision Maker ("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 13 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as "non-GAAP financial measures" in its evaluation of past performance and prospects for the future. The primary additional measures used by management are earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization 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 measurements 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, 2017	Three Months Ended June 30, 2016	Variance $	Variance %	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Variance $	Variance %
Net income	$ 189	$ 102	$ 87	85 %	$ 633	$ 304	$ 329	108 %
Add/(Subtract):								
Interest expense, net	127	114	13	11 %	256	227	29	13 %
Income tax expense/(benefit)	10	(5)	15	300 %	76	13	63	485 %
Depreciation and amortization	129	204	(75)	(37)%	250	319	(69)	(22)%
Depreciation and amortization of unconsolidated entities [(1)]	4	13	(9)	(69)%	18	25	(7)	(28)%
Selected Items Impacting Comparability - Adjusted EBITDA:								
(Gains)/losses from derivative activities net of inventory valuation adjustments [(2)]	(13)	119	(132)	**	(302)	242	(544)	**
Long-term inventory costing adjustments [(3)]	7	(67)	74	**	14	(44)	58	**
Deficiencies under minimum volume commitments, net [(4)]	(14)	8	(22)	**	(3)	34	(37)	**
Equity-indexed compensation expense [(5)]	9	11	(2)	**	12	15	(3)	**
Net (gain)/loss on foreign currency revaluation [(6)]	(10)	—	(10)	**	(14)	1	(15)	**
Line 901 incident [(7)]	12	—	12	**	12	—	12	**
Significant acquisition-related expenses [(8)]	1	—	1	**	6	—	6	**
Selected Items Impacting Comparability - segment adjusted EBITDA	(8)	71	(79)	**	(275)	248	(523)	**
(Gains)/losses from derivative activities [(2)]	(2)	(26)	24	**	2	(26)	28	**
Net (gain)/loss on foreign currency revaluation [(6)]	2	1	1	**	3	(3)	6	**
Selected Items Impacting Comparability - Adjusted EBITDA [(9)]	$ (8)	$ 46	$ (54)	**	$ (270)	$ 219	$ (489)	**
Adjusted EBITDA [(9)]	451	474	(23)	(5)%	963	1,107	(144)	(13)%
Interest expense, net [(10)]	(121)	(110)	(11)	(10)%	(246)	(219)	(27)	(12)%
Maintenance capital [(11)]	(71)	(35)	(36)	(103)%	(131)	(81)	(50)	(62)%
Current income tax expense	(1)	(9)	8	89 %	(11)	(40)	29	73 %
Adjusted equity earnings in unconsolidated entities, net of distributions [(12)]	32	(5)	37	**	18	(11)	29	**
Distributions to noncontrolling interests [(13)]	(1)	(1)	—	— %	(1)	(2)	1	50 %
Implied DCF [(14)]	$ 289	$ 314	$ (25)	(8)%	$ 592	$ 754	$ (162)	(21)%
Less: Distributions paid [(13)]	(399)	(433)			(798)	(866)		
DCF Excess/(Shortage) [(15)]	$ (110)	$ (119)			$ (206)	$ (112)		

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

(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 or 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 10 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities and our Preferred Distribution Rate Reset Option.

(3) We carry crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and writedowns of such inventory that result from price declines as a selected item impacting comparability. See Note 4 to our Consolidated Financial Statements included in Part IV of our 2016 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 2016 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 10 to our Condensed Consolidated Financial Statements for discussion regarding our currency exchange rate risk hedging activities.

(7) Includes costs recognized during the period related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance. See Note 12 to our Condensed Consolidated Financial Statements for additional information.

(8) Includes acquisition-related expenses associated with the ACC Acquisition. See Note 6 to our Condensed Consolidated Financial Statements for additional discussion.

(9) Adjusted EBITDA includes Other income/expense, net adjusted for selected items impacting comparability. Segment adjusted EBITDA is exclusive of such amounts.

(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 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 cash distributions received from such entities.

(13) Includes cash distributions that pertain to the current period's net income and are paid in the subsequent period.

(14) Including net costs recognized during the periods related to the Line 901 incident that occurred in May 2015, Implied DCF would have been $277 million and $580 million for the three and six months ended June 30, 2017, respectively. See Note 12 to our Condensed Consolidated Financial Statements for additional information regarding the Line 901 incident.

(15) Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes. DCF shortages are 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 or 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 13 to our Condensed Consolidated Financial Statements for a reconciliation of segment adjusted EBITDA to net income attributable to PAA.

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

Transportation Segment

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. The Transportation segment generates revenue through a combination of tariffs, 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)	**2017**	**2016**	**$**	**%**	**2017**	**2016**	**$**	**%**
Revenues								
Tariff activities	$ 393	$ 365	$ 28	8 %	$ 745	$ 715	$ 30	4 %
Trucking	32	38	(6)	(16)%	69	72	(3)	(4)%
Total transportation revenues	425	403	22	5 %	814	787	27	3 %
Costs and expenses								
Trucking costs	(21)	(24)	3	13 %	(45)	(45)	—	— %
Field operating costs (2)	(155)	(136)	(19)	(14)%	(293)	(274)	(19)	(7)%
Equity-indexed compensation expense - field operating costs	(3)	(5)	2	**	(6)	(5)	(1)	**
Segment general and administrative expenses (2) (3)	(21)	(21)	—	— %	(48)	(44)	(4)	(9)%
Equity-indexed compensation expense - general and administrative	(3)	(5)	2	**	(5)	(7)	2	**
Equity earnings in unconsolidated entities	68	40	28	70 %	121	87	34	39 %
Adjustments (4):								
Depreciation and amortization of unconsolidated entities	4	13	(9)	(69)%	18	25	(7)	(28)%
Deficiencies under minimum volume commitments, net	(14)	4	(18)	**	(9)	24	(33)	**
Equity-indexed compensation expense	5	5	—	**	6	7	(1)	**
Line 901 incident	12	—	12	**	12	—	12	**
Significant acquisition-related expenses	1	—	1	**	6	—	6	**
Segment adjusted EBITDA	$ 298	$ 274	$ 24	9 %	$ 571	$ 555	$ 16	3 %
Maintenance capital	$ 27	$ 23	$ 4	17 %	$ 57	$ 57	$ —	— %
Segment adjusted EBITDA per barrel	$ 0.63	$ 0.63	$ —	— %	$ 0.64	$ 0.65	$ (0.01)	(2)%

Average Daily Volumes	Three Months Ended June 30,		Variance		Six Months Ended June 30,		Variance	
(in thousands of barrels per day) (5)	2017	2016	Volumes	%	2017	2016	Volumes	%
Tariff activities volumes								
Crude oil pipelines (by region):								
Permian Basin (6)	2,761	2,178	583	27 %	2,614	2,112	502	24 %
South Texas / Eagle Ford (6)	349	274	75	27 %	330	294	36	12 %
Western	179	211	(32)	(15)%	184	193	(9)	(5)%
Rocky Mountain (6)	444	431	13	3 %	415	434	(19)	(4)%
Gulf Coast	385	613	(228)	(37)%	364	597	(233)	(39)%
Central (6)	427	398	29	7 %	416	388	28	7 %
Canada	363	379	(16)	(4)%	363	386	(23)	(6)%
Crude oil pipelines	4,908	4,484	424	9 %	4,686	4,404	282	6 %
NGL pipelines	156	182	(26)	(14)%	168	180	(12)	(7)%
Tariff activities total volumes	5,064	4,666	398	9 %	4,854	4,584	270	6 %
Trucking volumes	99	115	(16)	(14)%	106	110	(4)	(4)%
Transportation segment total volumes	5,163	4,781	382	8 %	4,960	4,694	266	6 %

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

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

(2) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(3) 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.

(4) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 13 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

(5) 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.

(6) 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 that is intended to offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff activities revenues.

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

Revenues from Tariff Activities, Equity Earnings in Unconsolidated Entities and Volumes. The following table presents variances in tariff activities revenues and equity earnings in unconsolidated entities by region for the comparative periods presented:

(in millions)	Favorable/(Unfavorable) Variance Three Months Ended June 30, 2017-2016 Revenues	Favorable/(Unfavorable) Variance Three Months Ended June 30, 2017-2016 Equity Earnings	Favorable/(Unfavorable) Variance Six Months Ended June 30, 2017-2016 Revenues	Favorable/(Unfavorable) Variance Six Months Ended June 30, 2017-2016 Equity Earnings
Tariff activities:				
Permian Basin region	$ 44	$ 7	$ 69	$ 7
South Texas / Eagle Ford region	(2)	9	(6)	12
Rocky Mountain region	(4)	4	(13)	6
Gulf Coast region	(5)	—	(17)	—
Other (including pipeline loss allowance revenue)	(5)	8	(3)	9
Total tariff activities variance	$ 28	$ 28	$ 30	$ 34

- Permian Basin region — The increase in revenues for the comparative 2017 periods presented was largely driven by (i) higher volumes on our Cactus pipeline due to stronger demand in the Corpus Christi market and third-party export terminals, which also favorably impacted volumes on our McCamey pipeline system, (ii) results from the ACC System, which we acquired in February 2017 and (iii) increased production in the Permian Basin, which favorably impacted volumes on our takeaway pipelines.

  Equity earnings increased due to higher earnings from our 50% interest in BridgeTex Pipeline Company, LLC resulting from higher volumes.

- South Texas / Eagle Ford region — Equity earnings from our 50% interest in Eagle Ford Pipeline LLC increased over the periods presented primarily due to higher volumes from our Cactus pipeline related to stronger demand in the Corpus Christi market and third-party export terminals.

- Rocky Mountain region — The decrease in revenues for the six-month comparative period was largely driven by (i) lower volumes due to downtime on our Wahsatch pipeline, which we proactively shut down for approximately 30 days during the first quarter of 2017 as a precautionary measure in response to indications of soil movement identified by our monitoring systems, and (ii) the sale of 50% of our investment in Cheyenne Pipeline in June 2016, subsequent to which it was accounted for under the equity method of accounting.

  Equity earnings increased primarily due to earnings from (i) our 40% investment in the entity that owns the Saddlehorn Pipeline, a segment of which was placed in service in the third quarter of 2016, and (ii) our 50% investment in Cheyenne Pipeline, as discussed above. Such increases were partially offset by decreased equity earnings from our 35.67% interest in White Cliffs Pipeline LLC due to lower volumes on the joint venture pipeline.

- Gulf Coast region — Revenues and volumes decreased primarily due to the sale of certain of our Gulf Coast pipelines in March 2016 and July 2016.

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 2016 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, shippers (i) 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. The increase in field operating costs (excluding equity-indexed compensation expense) for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 was primarily due to an increase in estimated costs associated with the Line 901 incident and incremental operating costs from the Alpha Crude

Connector acquisition in February 2017, partially offset by cost reduction efforts and decreased costs due to the sale of certain Gulf Coast pipelines as noted above.

Equity-Indexed Compensation Expense. The following table presents total equity-indexed compensation expense by segment (in millions):

	Three Months Ended June 30,			Six Months Ended June 30,		
Operating Segment	**2017**	**2016**	**Variance**	**2017**	**2016**	**Variance**
Transportation	$ 6	$ 10	$ (4)	$ 11	$ 12	$ (1)
Facilities	2	6	(4)	4	6	(2)
Supply and Logistics	3	6	(3)	7	8	(1)
	$ 11	$ 22	$ (11)	$ 22	$ 26	$ (4)

Across all segments, equity-indexed compensation expense decreased by $11 million and $4 million for the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016, primarily due to a decrease in unit price for both the three and six months ended June 30, 2017, compared to an increase in unit price for the same periods in 2016, partially offset by more probable awards outstanding and a higher average value for those awards during the three and six months ended June 30, 2017 compared to the same periods in 2016. See Note 16 to our Consolidated Financial Statements included in Part IV of our 2016 Annual Report on Form 10-K for additional information regarding our equity-indexed compensation plans.

Facilities Segment

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

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

Operating Results (1)	**Three Months Ended June 30,**		**Variance**		**Six Months Ended June 30,**		**Variance**	
(in millions, except per barrel data)	**2017**	**2016**	**$**	**%**	**2017**	**2016**	**$**	**%**
Revenues	$ 289	$ 270	$ 19	7 %	$ 582	$ 535	$ 47	9 %
Natural gas related costs	(6)	(6)	—	— %	(17)	(11)	(6)	(55)%
Field operating costs [2]	(85)	(88)	3	3 %	(168)	(173)	5	3 %
Equity-indexed compensation expense - field operating costs	—	(2)	2	**	(1)	(2)	1	**
Segment general and administrative expenses [2] [3]	(16)	(14)	(2)	(14)%	(34)	(30)	(4)	(13)%
Equity-indexed compensation expense - general and administrative	(2)	(4)	2	**	(3)	(4)	1	**
Adjustments [4]:								
Deficiencies under minimum volume commitments, net	—	4	(4)	**	6	10	(4)	**
(Gains)/losses from derivative activities net of inventory valuation adjustments	(1)	(2)	1	**	1	(1)	2	**
Equity-indexed compensation expense	1	3	(2)	**	2	3	(1)	**
Segment adjusted EBITDA	$ 180	$ 161	$ 19	12 %	$ 368	$ 327	$ 41	13 %
Maintenance capital	$ 39	$ 9	$ 30	333 %	$ 66	$ 18	$ 48	267 %
Segment adjusted EBITDA per barrel	$ 0.45	$ 0.42	$ 0.03	7 %	$ 0.46	$ 0.43	$ 0.03	7 %

	Three Months Ended June 30,		**Variance**		**Six Months Ended June 30,**		**Variance**	
Volumes (5)	**2017**	**2016**	**Volumes**	**%**	**2017**	**2016**	**Volumes**	**%**
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	112	105	7	7 %	112	105	7	7 %
Rail load / unload volumes (average volumes in thousands of barrels per day)	48	127	(79)	(62)%	41	109	(68)	(62)%
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	97	—	— %	97	97	—	— %
NGL fractionation (average volumes in thousands of barrels per day)	119	105	14	13 %	122	110	12	11 %
Facilities segment total volumes (average monthly volumes in millions of barrels) [6]	134	128	6	5 %	133	128	5	4 %

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

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

(2) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(3) 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.

(4) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 13 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

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

(6) Facilities segment total volumes is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the period and divided by the number of months in the period; (iii) 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 (iv) 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 and Volumes. Variances in revenues and average monthly volumes for the comparative periods were driven by:

- NGL Storage, NGL Fractionation and Canadian Natural Gas Processing — Revenues increased by $26 million and $59 million for the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016 primarily due to contributions from the Western Canada NGL assets we acquired in August 2016 and increased storage capacity at our Fort Saskatchewan facility, as well as higher fees at certain of our NGL storage and fractionation facilities, which were largely incurred in our Supply and Logistics segment results.

- Rail Terminals — Revenues decreased by $8 million and $16 million for the three and six months ended June 30, 2017, respectively, compared to the three and six months ended June 30, 2016 primarily due to lower volumes at our U.S. terminals resulting from less favorable market conditions, partially offset by revenues and volumes from our Fort Saskatchewan rail terminal that came on line in April 2016.

- Crude Oil Storage — Revenues decreased by $1 million and $4 million for the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016 primarily due to (i) decreased utilization at certain of our West Coast terminals and (ii) lower results related to the sale of certain of our East Coast terminals in April 2016. Such decreases were partially offset by increased revenues from our Cushing and St. James terminals due to aggregate capacity expansions of over 2.8 million barrels and higher ancillary fees.

Field Operating Costs. The decrease in field operating costs (excluding equity-indexed compensation expense) for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 was primarily due to reduced rail activity, cost reduction efforts and the sale of certain of our East Coast terminals in April 2016. Such decreases were largely offset by an increase in operating costs associated with the Western Canada NGL assets acquired in August 2016.

Equity-indexed compensation expense. See "—Analysis of Operating Segments—Transportation Segment" for discussion of equity-indexed compensation expense for the periods presented.

Maintenance Capital. Maintenance capital consists of 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. The increase in maintenance capital for the three and six months ended June 30, 2017 compared to the same periods in 2016 was primarily due to increased investment in our integrity management program, primarily on assets at our West Coast terminals.

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 purchased from suppliers and natural gas sales attributable to the activities that were previously performed by our natural gas storage commercial optimization group. Generally, our segment profit is impacted by (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchases volumes, NGL sales volumes and waterborne cargos), (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 segment profit 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)	**2017**	**2016**	**$**	**%**	**2017**	**2016**	**$**	**%**
Revenues	$ 5,783	$ 4,652	$ 1,131	24 %	$ 12,184	$ 8,473	$ 3,711	44 %
Purchases and related costs	(5,708)	(4,566)	(1,142)	(25)%	(11,678)	(8,243)	(3,435)	(42)%
Field operating costs (2)	(65)	(74)	9	12 %	(131)	(155)	24	15 %
Equity-indexed compensation expense - field operating costs	—	(1)	1	**	(1)	(1)	—	**
Segment general and administrative expenses (2) (3)	(23)	(24)	1	4 %	(46)	(48)	2	4 %
Equity-indexed compensation expense - general and administrative	(3)	(5)	2	**	(6)	(7)	1	**
Adjustments (4):								
(Gains)/losses from derivative activities net of inventory valuation adjustments	(12)	121	(133)	**	(303)	243	(546)	**
Long-term inventory costing adjustments	7	(67)	74	**	14	(44)	58	**
Net (gain)/loss on foreign currency revaluation	(10)	—	(10)	**	(14)	1	(15)	**
Equity-indexed compensation expense	3	3	—	**	4	5	(1)	**
Segment adjusted EBITDA	$ (28)	$ 39	$ (67)	(172)%	$ 23	$ 224	$ (201)	(90)%
Maintenance capital	$ 5	$ 3	$ 2	67 %	$ 8	$ 6	$ 2	33 %
Segment adjusted EBITDA per barrel	$ (0.27)	$ 0.41	$ (0.68)	(166)%	$ 0.11	$ 1.07	$ (0.96)	(90)%

Average Daily Volumes	**Three Months Ended June 30,**		**Variance**		**Six Months Ended June 30,**		**Variance**	
(in thousands of barrels per day)	**2017**	**2016**	**Volumes**	**%**	**2017**	**2016**	**Volumes**	**%**
Crude oil lease gathering purchases	940	885	55	6 %	929	899	30	3 %
NGL sales	210	176	34	19 %	280	242	38	16 %
Waterborne cargos	—	5	(5)	(100)%	3	6	(3)	(50)%
Supply and Logistics segment total	1,150	1,066	84	8 %	1,212	1,147	65	6 %

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

(1) Revenues and costs include intersegment amounts.

(2) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(3) 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.

(4) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 13 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

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, 2017	$ 43	$ 53
Three months ended June 30, 2016	$ 36	$ 51
Six months ended June 30, 2017	$ 43	$ 54
Six months ended June 30, 2016	$ 26	$ 51

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, 2017 compared to the same periods in 2016 primarily due to higher crude oil prices. Additionally, revenues were impacted by gains from certain derivative activities during the three and six months ended June 30, 2017 compared to losses recognized during the 2016 periods.

Historically, we expected a base level of earnings from our Supply and Logistics segment from the assets employed by this segment. However, over the last 12 to 18 months, competition has increased significantly and, combined with recent and current market conditions, predicting such base level of earnings has been difficult. Our Supply and Logistics segment earnings may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. During certain transitional periods, such as the current extended period of lower crude oil prices, increased competition, low volatility and tight differentials, our ability to generate earnings in this segment is reduced and our segment earnings can be adversely impacted by activities designed to increase utilization of certain of our pipeline and facilities assets. These factors, in combination with overcapacity of midstream assets in certain regions and increased competition that currently exists in most crude oil producing regions, make predicting and then generating baseline-level performance challenging. Our NGL operations are also impacted by similar competitive pressures. In addition, 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.

Net Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs, decreased by $11 million for the three months ended June 30, 2017 compared to the three months ended June 30, 2016 and increased by $276 million for the six months ended June 30, 2017 compared to the same period in 2016. The six-month comparative period was impacted by gains from certain derivative activities (as discussed further below) that more than offset lower results from less favorable market conditions. The following summarizes the significant items impacting the comparative periods:

- Crude Oil Operations — Net revenues from our crude oil supply and logistics activities decreased for the three and six months ended June 30, 2017 as compared to the same periods in 2016, primarily due to continued and intensifying competition, largely due to overbuilt infrastructure underwritten with volume commitments and the effect of such on differentials, which negatively impacted our unit margins. See the "Outlook" section below for additional discussion of recent market conditions.

- NGL Operations — Net revenues from our NGL operations decreased for the three and six months ended June 30, 2017 as compared to the three and six months ended June 30, 2016, largely due to (i) higher supply costs and tighter differentials driven by competition, which more than offset higher sales volume from the Western Canada NGL assets acquired in August 2016, (ii) warmer weather during the 2016-2017 heating season and (iii) higher storage and processing fees for the 2017 period, which were largely offset in our Facilities segment results.

- 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 10 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities. These gains and losses impact our net revenues but are excluded from segment adjusted EBITDA and thus are reflected as an "Adjustment" in the table above.

- Long-Term Inventory Costing Adjustments — Our net revenues are impacted by changes in the weighted average cost of our crude oil and NGL inventory pools that result from price movements during the periods. These costing adjustments related to long-term inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that was needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. These costing adjustments impact our net revenues but are excluded from segment adjusted EBITDA and thus are reflected as an "Adjustment" in the table above.

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

Field Operating Costs. The decrease in field operating costs (excluding equity-indexed compensation expense) for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 was primarily due to lower trucking costs as pipeline expansion projects were placed into service.

Equity-indexed compensation expense. See "—Analysis of Operating Segments—Transportation Segment" for discussion of equity-indexed compensation expense for the periods presented.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense decreased for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 primarily due to (i) impairment losses in the second quarter of 2016 of approximately $80 million associated with certain of our rail and other terminal assets, (ii) an approximately $18 million loss on assets taken out of service during the second quarter of 2016 and (iii) the write-off of approximately $2 million and $11 million of costs during 2017 and 2016, respectively, associated with the discontinuation of certain capital projects. These decreases were partially offset by additional depreciation and amortization expense associated with recently acquired assets and the completion of various capital expansion projects during the comparative periods. Depreciation and amortization expense was further impacted by net losses for the three and six months ended June 30, 2017 of approximately $5 million and $1 million, respectively, and net gains for the three and six months ended June 30, 2016 of approximately $10 million and $16 million, respectively, associated with sales of non-core assets during the periods and the Cheyenne Pipeline joint venture formation in June 2016.

Interest Expense

The increase in interest expense for the three and six months ended June 30, 2017 over the three and six months ended June 30, 2016 was primarily due to (i) lower capitalized interest driven by fewer capital projects under construction and (ii) a higher weighted average debt balance during the 2017 periods.

Other Income/(Expense), Net

The decrease in Other income/(expense), net for the three and six months ended June 30, 2017 compared to the same periods in 2016 was primarily related to the mark-to-market adjustment of our Preferred Distribution Rate Reset Option, which was a gain of $2 million and a loss of $2 million for the three and six months ended June 30, 2017, respectively, compared to a gain of $25 million for the three and six months ended June 30, 2016. See Note 10 to our Condensed Consolidated Financial Statements for additional information. Excluding such impacts, Other income/(expense), net for the periods presented were primarily comprised of gains or losses from the revaluation of foreign currency transactions and monetary assets and liabilities.

Income Tax Expense

Income tax expense increased for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 primarily due to higher year-over-year income as impacted by fluctuations in derivative mark-to-market valuations in our Canadian operations.

Outlook

Market Overview and Outlook

See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Market Overview and Outlook” included in Item 7 of our 2016 Annual Report on Form 10-K for a discussion of historical crude oil market conditions and our view on potential drilling and production activity levels. The increase in crude oil prices during the fourth quarter of 2016 and early 2017 led to increased rig activity in areas where we anticipated production levels to increase, most notably the Permian Basin and the STACK resource play in Oklahoma. In the second quarter of 2017, crude oil prices trended downward, averaging 7% below the first quarter average.

However, rig activity during the second quarter continued to increase in many of the producing basins where we operate, although at a slower rate compared to the first quarter. Since early May 2017, Permian Basin rig counts have increased by 7%, adding approximately 26 rigs over the ensuing three month period. In addition, upstream acreage acquisition activity in the Permian Basin continued in the second quarter of 2017, with over $13 billion in acreage transactions announced within the last twelve months, which involved meaningful positions located in the Northern Delaware Basin. Current rig counts do not fully reflect the expected increase associated with certain of these transactions. We expect a continuation of a time lag between increased drilling activity and increased production as producers shift to multiple well pad operations and delayed scheduling of completion activities. These trends have led to a rising inventory of drilled but uncompleted (“DUC”) wells in the Permian Basin. In the Permian Basin alone, DUC inventory has increased by nearly 1,000 DUCs since the beginning of 2016. Importantly, over 80% of the increase in DUC inventory accumulated within the first half of 2017, during which DUC additions averaged approximately 140 per month. While the timing of DUC completion activity is difficult to forecast, DUC inventory and increases in well productivity could have a positive impact on either the rate of production growth or the ability of producers to maintain production at current levels in the event rig activity slows.

Taking all of these factors into account, we continue to expect production levels to increase in the second half of this year. The increased production levels should continue to increase pipeline utilization in our Transportation segment. Longer term, we believe rising production levels will also provide some potential relief on the margin compression we have been experiencing within our Supply and Logistics segment. However, we can provide no assurance that an improvement in market conditions will be achieved or that we will not be negatively impacted by declining crude oil supply, lower commodity prices, reduced producer activity levels, competition for incremental volumes, reduced margins, low levels of volatility, challenging capital markets conditions or other related factors. A continuation of a low crude oil price environment could have a material adverse impact on drilling and completion activity. Additionally, construction of additional infrastructure by us and our competitors could lead to even greater levels of excess takeaway capacity in certain areas for the near- to medium-term, which could further reduce unit margins in our various segments, and which could be exacerbated by declining levels of crude oil production. Specifically, our Supply and Logistics segment has been most heavily impacted by margin compression driven by factors such as these. Within this segment, our crude oil activities were the first to experience significant margin compression, and most recently, our NGL activities have become adversely impacted by margin compression as well, substantially driven by increased competition in supply areas and tighter differentials between Canadian and U.S. markets. In addition, in the current environment of increased competition, relatively flat futures curves, narrow grade differentials and low regional basis differentials, the prospects for capturing arbitrage opportunities of the type and amount that we have historically been able to capture is significantly reduced. The near term outlook for our Supply and Logistics segment is that such conditions are likely to continue; accordingly, our earnings from this segment are difficult to forecast and we can provide no assurance that conditions will improve or that we will be able to achieve our earnings objectives in this segment. Finally, we cannot be certain that our expansion efforts will generate targeted returns or that any recently completed or future acquisition activities will be successful. See "Risk Factors—Risks Related to Our Business" discussed in Item 1A of our 2016 Annual Report on Form 10-K.

Outlook for Certain Idled and Underutilized Assets

During 2015, we shut down Line 901 and a portion of Line 903 in California following the release of crude oil (see Note 12 to our Condensed Consolidated Financial Statements for additional information). During the period since these pipelines were idled, we have been assessing potential alternatives in order to return them to operation. Some of the alternatives under consideration could result in incurring costs associated with retiring certain assets or an impairment of some or all of the carrying value of the idled property and equipment, which was approximately $124 million and $94 million as of June 30, 2017 and December 31, 2016, respectively.

We own a 54% undivided joint interest in the Capline Pipeline ("Capline") system, which originates in St. James, Louisiana and terminates in Patoka, Illinois. We anticipate the construction of new crude oil pipeline infrastructure and the ongoing changing crude oil flows in the United States may result in a decline in volumes on the Capline system in future years to levels that cannot sustain operations. The owners of the Capline system are considering various alternatives for the use of the pipeline system, including an assessment of the commercial potential to reverse the pipeline direction within the next several years. Developments in the commercial outlook for the Capline system could result in incurring costs associated with retiring certain assets or an impairment of the carrying value of our interest in the Capline system, which was $196 million and $227 million at June 30, 2017 and December 31, 2016, respectively.

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 non-core asset sales program, as further discussed below in the section entitled "—Acquisitions, Investments, Expansion 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 and 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 non-core assets. As of June 30, 2017, we had a working capital deficit of $229 million and approximately $2.8 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, 2017
Availability under senior unsecured revolving credit facility [(1) (2)]	$ 1,584
Availability under senior secured hedged inventory facility [(1) (2)]	1,011
Availability under senior unsecured 364-day revolving credit facility	1,000
Amounts outstanding under commercial paper program	(836)
Subtotal	2,759
Cash and cash equivalents	47
Total	$ 2,806

(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 was reduced by outstanding letters of credit of $105 million, comprised of $16 million under the senior unsecured revolving credit facility and $89 million under the senior secured hedged inventory facility.

We believe that we have, and will continue to have, the ability to access the commercial paper program and/or credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains solid 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. Also, see Item 1A. “Risk Factors” of our 2016 Annual Report on Form 10-K for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities, which provide the backstop for the commercial paper program, is subject to ongoing compliance with covenants. As of June 30, 2017, we were in compliance with all such covenants.

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 2016 Annual Report on Form 10-K.

Net cash provided by operating activities for the first six months of 2017 and 2016 was $1.461 billion and $387 million, respectively, and primarily resulted from earnings from our operations.

Net cash provided by operating activities for the 2017 period was positively impacted by a decrease in 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.

During the six months ended June 30, 2016, we increased our inventory levels and margin balances required as part of our hedging activities that were funded by short-term debt, resulting in an unfavorable impact on our cash provided by operating activities.

Minimum Volume Commitments. We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. 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 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. Deferred revenue associated with non-performance under minimum volume contracts could be significant and could adversely affect our profitability and earnings, but generally does not impact our liquidity.

At June 30, 2017 and December 31, 2016, counterparty deficiencies associated with agreements that include minimum volume commitments totaled $62 million and $66 million, respectively, of which $46 million and $54 million, respectively, was recorded as deferred revenue. The remaining balance of $16 million and $12 million at June 30, 2017 and December 31, 2016, respectively, was related to deficiencies for which the counterparties had not met their contractual minimum commitments and were not reflected in our Condensed Consolidated Financial Statements as we had not yet billed or collected such amounts.

Acquisitions, Investments, Expansion 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 asset sales program, as discussed further below. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital.

Acquisitions. During the six months ended June 30, 2017 and 2016, we paid cash of $1.281 billion (net of cash acquired of $4 million) and $85 million, respectively, for acquisitions. The acquisitions completed during the six months ended June 30, 2017 primarily included the ACC System located in the Northern Delaware Basin in Southeastern New Mexico and West Texas. See Note 6 to our Condensed Consolidated Financial Statements for additional information regarding the ACC Acquisition. The ACC Acquisition was initially funded through borrowings under our senior unsecured revolving credit facility. Such borrowings were subsequently repaid with proceeds from our March 2017 issuance of common units to AAP pursuant to the Omnibus Agreement and in connection with a PAGP underwritten equity offering. Additionally, we and an affiliate of

Noble Midstream Partners LP completed the acquisition of Advantage Pipeline, L.L.C. for a purchase price of $133 million through a newly formed 50/50 joint venture. For our 50% share ($66.5 million), we contributed approximately 1.3 million common units and approximately $26 million in cash.

2017 Capital Projects. We invested approximately $614 million in midstream infrastructure during the six months ended June 30, 2017, and we expect to invest approximately $950 million during the year ended December 31, 2017. See "—Acquisitions and Capital Projects" for detail of our projected capital expenditures for the year ending December 31, 2017. The majority of funding for our 2017 capital program was provided by proceeds from our common unit issuances during the first quarter of 2017, with the remaining funding expected to be provided by the sale of various non-core assets throughout the year.

Divestitures. Our strategic divestiture program includes the evaluation of 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. We sold certain non-core assets for proceeds of $389 million during the six months ended June 30, 2017. In addition, we entered into a definitive agreement in 2016 for an approximately $290 million sale of non-core assets for which regulatory approval is still pending. During the third quarter of 2017, we also entered into an additional definitive agreement to sell our interests in certain non-core pipelines in the Rocky Mountains for proceeds of approximately $250 million, and we are in various stages of discussion or advanced discussion and negotiations regarding additional sales of non-core assets or partial sales of assets to strategic partners for potential additional proceeds of approximately $150 million to $350 million. See Note 6 to our Condensed Consolidated Financial Statements for additional information regarding these asset sales 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 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.

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"). Our issuances of equity securities associated with our Continuous Offering Program have been issued pursuant to the Traditional Shelf. At June 30, 2017, 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 WKSI Shelf during the six months ended June 30, 2017.

Sales of Common Units. The following table summarizes our sales of common units during the six months ended June 30, 2017 (net proceeds in millions):

Type of Offering	Common Units Issued		Net Proceeds [1]	
Continuous Offering Program	4,033,567		$ 129	[2]
Omnibus Agreement [3]	50,086,326	[4]	1,535	
	54,119,893		**$ 1,664**	

(1) Amounts are net of costs associated with the offerings.

(2) We pay commissions to our sales agents in connection with common units issuances under our Continuous Offering Program. We paid $1 million of such commissions during the six months ended June 30, 2017.

(3) Pursuant to the Omnibus Agreement entered into by the Plains Entities in connection with the Simplification Transactions, PAGP has agreed to use the net proceeds from any public or private offering and sale of Class A shares, after deducting the sales agents' commissions and offering expenses, to purchase from AAP a number of AAP units equal to the number of Class A shares sold in such offering at a price equal to the net proceeds from such offering. The Omnibus Agreement also provides that immediately following such purchase and sale, AAP will use the net proceeds it receives from such sale of AAP units to purchase from us an equivalent number of our common units.

(4) Includes (i) approximately 1.8 million common units issued to AAP in connection with PAGP's issuance of Class A shares under its Continuous Offering Program and (ii) 48.3 million common units issued to AAP in connection with PAGP's March 2017 underwritten offering.

Credit Agreements, Commercial Paper Program and Indentures. Our credit agreements (which impact our ability to access our commercial paper program because they provide the 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, 2017, we were in compliance with the covenants contained in our credit agreements and indentures.

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.

During the six months ended June 30, 2016, we had net repayments under our credit facilities and commercial paper program of $592 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 inventory purchases and related margin balances required as part of our hedging activities.

Distributions to Our Unitholders

Distributions to our Series A preferred unitholders. On August 14, 2017, we will issue 1,339,796 additional Series A preferred units in lieu of paying a cash distribution of $35 million. See Note 9 to our Condensed Consolidated Financial Statements for details of distributions made during or pertaining to the first six months of 2017.

Distributions to our common unitholders. In accordance with our partnership agreement, after making distributions to holders of outstanding Series A preferred units, we distribute all 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, 2017, we will pay a quarterly distribution of $0.55 per common unit, which is unchanged from our prior three quarterly distributions, but represents a year-over-year distribution decrease of approximately 21%. See Note 9 to our Condensed Consolidated Financial Statements for details of distributions paid during or pertaining to the first six months of 2017. 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 2016 Annual Report on Form 10-K for additional discussion regarding distributions.

On August 7, 2017, we announced that we were engaged in discussions with our Board of Directors regarding a reassessment of our approach to distributions, with a focus on resetting PAA's common unit distribution to a level supported by the distributable cash flow from our fee-based Transportation and Facilities segments. As of such date, no final decisions had been made regarding such potential change, but we indicated that we intended to complete our reassessment and finalize any changes over the course of the ensuing sixty day period.

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 12 to our Condensed Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years, with a limited number of contracts with remaining terms extending up to approximately 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 others due under the specified contractual obligations as of June 30, 2017 (in millions):

	Remainder of 2017	2018	2019	2020	2021	2022 and Thereafter	Total
Long-term debt, including current maturities and related interest payments [1]	$ 399	$ 1,054	$ 1,270	$ 870	$ 940	$ 11,054	$ 15,587
Leases and rights-of-way easements [2]	94	170	143	122	100	446	1,075
Other obligations [3]	296	236	163	132	129	517	1,473
Subtotal	789	1,460	1,576	1,124	1,169	12,017	18,135
Crude oil, NGL and other purchases [4]	3,162	2,879	2,072	1,427	1,201	4,012	14,753
Total	$ 3,951	$ 4,339	$ 3,648	$ 2,551	$ 2,370	$ 16,029	$ 32,888

(1) Includes debt service payments, interest payments due on senior notes and the commitment fee on assumed available capacity under our credit facilities and long-term borrowings under our 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 facilities or commercial paper program) in the amounts above.

(2) Leases are primarily for (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks, trailers and railcars. Includes capital and operating 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 $800 million associated with an agreement to transport crude oil 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 2017. 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 of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs, derivative transactions and construction activities. At June 30, 2017 and December 31, 2016, we had outstanding letters of credit of approximately $105 million and $73 million, respectively.

Off-Balance Sheet Arrangements

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

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For a discussion regarding our critical accounting policies and estimates, see “Critical Accounting Policies and Estimates” under Item 7 of our 2016 Annual Report on Form 10-K.

FORWARD-LOOKING STATEMENTS

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

- declines in the 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 producer over-commitments to new or recently constructed 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, refined products 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;
- failure to implement or capitalize, or delays in implementing or capitalizing, on expansion projects, whether due to permitting delays, permitting withdrawals or other factors;
- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- 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 failure to consummate, or significant delay in consummating, sales of assets or interests as a part of our strategic divestiture program;
- 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 availability of, and our ability to consummate, acquisition or combination opportunities;
- the effectiveness of our risk management activities;
- 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;
- 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 and refined products, 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 2016 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

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

- *Crude oil*

  We utilize crude oil derivatives to hedge commodity price risk inherent in our Supply and Logistics and Transportation segments. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory, 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 butane and propane 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 10 to our Condensed Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

The fair value of our commodity derivatives and the change in fair value as of June 30, 2017 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	$ 21	$ (43)	$ 43
Natural gas	(13)	$ 11	$ (11)
NGL and other	18	$ (49)	$ 49
Total fair value	$ 26		

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, 2017, approximately $1.1 billion, was subject to interest rate re-sets that range from less than one week to approximately three months. The average interest rate on variable rate debt that was outstanding during the six months ended June 30, 2017 was 1.9%, based upon rates in effect during such period. The fair value of our interest rate derivatives was a liability of $32 million as of June 30, 2017. A 10% increase in the forward LIBOR curve as of June 30, 2017 would have resulted in an increase of $33 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of June 30, 2017 would have resulted in a decrease of $33 million to the fair value of our interest rate derivatives. See Note 10 to our Condensed Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives was an asset of $3 million as of June 30, 2017. A 10% increase in the exchange rate (USD-to-CAD) would have resulted in a decrease of $19 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would have resulted in an increase of $19 million to the fair value of our foreign currency derivatives. See Note 10 to our Condensed Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

Preferred Distribution Rate Reset Option

The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value in our Condensed Consolidated Balance Sheets. The valuation model utilized for this embedded derivative contains inputs including our common unit price, ten-year U.S. treasury rates and default probabilities 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 $35 million as of June 30, 2017. A 10% increase in the fair value would have an impact of $3 million. A 10% decrease in the fair value would also have an impact of $3 million. See Note 10 to our Condensed Consolidated Financial Statements for a discussion of embedded derivatives.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

Applicable SEC rules require an evaluation of the effectiveness of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our DCP as of June 30, 2017, 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 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

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

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included in Note 12 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 2016 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

Common Units. On April 3, 2017, we and an affiliate of Noble Midstream Partners LP ("Noble") completed the acquisition of Advantage Pipeline, L.L.C. ("Advantage") for a purchase price of $133 million through a newly formed 50/50 joint venture. For our 50% share ($66.5 million), we contributed 1,252,269 common units and approximately $26 million in cash. The issuance of such common units was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof. See Note 6 and Note 9 to our Condensed Consolidated Financial Statements for additional information regarding the issuance of common units in connection with the Advantage transaction.

Series A Preferred Units. With respect to any quarter ending on or prior to December 31, 2017, we may elect to pay distributions on our Series A preferred units in additional preferred units, in cash or a combination of both. During the three months ended June 30, 2017 we issued 1,313,527 additional Series A preferred units in lieu of a cash distribution of $34 million. The issuance of the Series A preferred units, in connection with the quarterly distribution for the Series A preferred units, was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof. Our Series A preferred units are convertible into common units, generally on a one-for-one basis and subject to customary antidiultion adjustments and certain minimum conversion amounts, at any time after January 28, 2018. See Note 11 to our Consolidated Financial Statements included in Part IV of our 2016 Annual Report on Form 10-K for additional information regarding our Series A preferred units.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. MINE SAFETY DISCLOSURES

None.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

The exhibits listed on the accompanying Exhibit Index are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, 2017

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

August 8, 2017

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

August 8, 2017

EXHIBIT INDEX

2.1 *	—	Securities Purchase Agreement dated as of January 19, 2017 by and between COG Operating LLC, as seller, and Plains Pipeline, L.P., as purchaser (the schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K) (incorporated by reference to Exhibit 2.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
2.2 *	—	Securities Purchase Agreement dated as of January 19, 2017 by and between Frontier Midstream Solutions, LLC, as seller, and Plains Pipeline, L.P., as purchaser (the schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K) (incorporated by reference to Exhibit 2.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
3.1	—	Sixth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of November 15, 2016 (incorporated by reference to Exhibit 3.5 to our Current Report on Form 8-K filed November 21, 2016).
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).
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	—	Thirteenth Supplemental Indenture (Series A and Series B 6.50% Senior Notes due 2018) dated April 23, 2008 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 April 23, 2008).
4.5	—	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 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 April 20, 2009).
4.6	—	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).
4.7	—	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).
4.8	—	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).
4.9	—	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).
4.10	—	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).
4.11	—	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).
4.12	—	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).
4.13	—	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).

4.14	—	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).
4.15	—	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).
4.16	—	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).
4.17	—	Twenty-Ninth Supplemental Indenture (4.65% Senior Notes due 2025) dated August 24, 2015, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 26, 2015).
4.18	—	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).
4.19	—	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).
4.20	—	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).
4.21	—	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 **	—	Form of Director LTIP Grant Letter (February 2017) - Director Grant - Designated Directors and Audit Committee Members (PAA Plan) (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.2 **	—	Form of Director LTIP Grant Letter (February 2017) - Audit Committee Supplement (PAA Plan) (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.3 **	—	Form of Director LTIP Grant Letter (February 2017) - Independent Director Grant (PAA Plan) (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.4 ** †	—	Form of LTIP Grant Letter for Officers (July 2017)
12.1 †	—	Computation of Ratio of Earnings to Fixed Charges.
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

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† Filed herewith.

†† Furnished herewith.

* Certain schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule will be furnished supplementally to the SEC upon request.

** Management compensatory plan or arrangement.

PLAINS ALL AMERICAN

July 5, 2017

[name]
[address]

Re: Grant of Phantom Units

Dear [name]:

I am pleased to inform you that you have been granted [amount] Phantom Units as of the above date pursuant to the Company's Long-Term Incentive Plan (the "Plan"). In addition, in tandem with each Phantom Unit you have been granted a distribution equivalent right (a "DER"). A DER represents the right to receive a cash payment equivalent to the amount, if any, paid in cash distributions on one Common Unit of Plains All American Pipeline, L.P. ("PAA" or the "Partnership") to the holder of such Common Unit. The terms and conditions of this grant are as set forth below.

1. Subject to the further provisions of this Agreement, your Phantom Units shall vest (become payable in the form of one Common Unit of PAA for each Phantom Unit) on the Partnership's May 2019 Distribution Date.

2. Subject to the further provisions of this Agreement, your DERs shall vest (become payable in cash) upon and effective with the August 2017 Distribution Date.

3. Your DERs shall not accrue payments prior to vesting.

4. The number of Phantom Units subject to this award shall be proportionately reduced or increased for any split or reverse split, respectively, of the Units, or any event or transaction having a similar effect.

5. Upon vesting of your Phantom Units, your DERs will expire. Any such DERs that are payable on the Distribution Date on which the Phantom Units vest, shall be payable on such Distribution Date prior to their expiration.

6. In the event of the termination of your employment with the Company and its Affiliates for any reason (other than in connection with a Change in Status or by reason of your death or "disability," as defined in paragraph 7 below), all of your then outstanding DERs (regardless of vesting) and Phantom Units shall automatically be forfeited as of the date of termination; provided, however, that if the Company or its Affiliates terminate your employment other than as a result of a Termination for Cause: (i) any unvested Phantom Units shall be deemed nonforfeitable on the date of termination, and shall vest on the next following Distribution Date; and (ii) any DERs associated

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with such unvested, nonforfeitable Phantom Units described in clause (i) immediately preceding shall not be forfeited on the date of termination, but shall vest in accordance with paragraph 2 above and if vested shall be payable and shall expire in accordance with paragraph 5 above.

7. In the event of the termination of your employment with the Company and its Affiliates by reason of your death or your "disability" (a physical or mental infirmity that impairs your ability substantially to perform your duties for a period of eighteen months or that the Company otherwise determines constitutes a "disability"), your then outstanding Phantom Units shall be deemed nonforfeitable on the date of termination and shall vest on the next following Distribution Date (and any DERs associated with such unvested, nonforfeitable Phantom Units shall not be forfeited on the date of termination, but shall vest in accordance with paragraph 2 above and if vested shall be payable and shall expire in accordance with paragraph 5 above). As soon as administratively practicable after the vesting of any Phantom Units pursuant to this paragraph 7, payment will be made in cash in an amount equal to the Market Value of the number of Phantom Units vesting.

8. In the event of a Change in Status, all of your then outstanding Phantom Units and tandem DERs shall be deemed 100% nonforfeitable on such date, and such Phantom Units shall vest in full upon the next Distribution Date.

9. Upon payment pursuant to a DER, the Company will withhold any taxes due from your compensation as required by law. Upon vesting of a Phantom Unit, the Company will withhold any taxes due from your compensation as required by law, which (in the sole discretion of the Company) may include withholding a number of Common Units otherwise payable to you.

As used herein, (i) the "Company" refers to Plains All American GP LLC; (ii) "Distribution Date" means the day in February, May, August or November in any year (as context dictates) that is 45 days after the end of the most recently completed calendar quarter (or, if not a business day, the closest previous business day); and (iii) "Market Value" means the average of the closing sales prices for a Common Unit on the New York Stock Exchange for the five trading days preceding the then most recent "ex dividend" date for payment of a distribution by the Partnership.

The phrase "Change in Status" means (A) the termination of your employment by the Company other than a Termination for Cause, within two and a half months prior to or one year following a Change of Control (the "Protected Period"), (B) the termination of your employment by you due to the occurrence during the Protected Period, without your written consent, of (i) any material diminution in your authority, duties or responsibilities, (ii) any material reduction in your base salary or (iii) any other action or inaction that constitutes a material breach of this Agreement by the Company, or (C) the termination of your employment with the Company as a result of retirement on terms and timing that are approved by the CEO. A termination by you pursuant to

(B) above shall not be a Change in Status unless (1) you provide written notice to the Company of the condition in (B)(i), (ii) or (iii) that would constitute a Change in Status within 90 days of the initial existence of the condition and (2) the Company fails to remedy the condition within the 30-day period following such notice.

The phrase "Change of Control" means, and shall be deemed to have occurred upon the occurrence of, one or more of the following events: (i) Plains GP Holdings, L.P. ("PAGP") ceases to retain direct or indirect control of the general partner of the Partnership; (ii) PAGP ceases to beneficially own, directly or indirectly, more than 50% of the membership interest in the Company; (iii) any direct or indirect sale, lease, exchange or other transfer (in one transaction or a series of related transactions and whether by merger or otherwise) of all or substantially all of the assets of the Partnership, PAGP or the Company to one or more Persons who are not affiliates of PAGP ("third party or parties"), other than a transaction in which the Owner Affiliates (as defined below) continue to beneficially own, directly or indirectly, more than 50% of the issued and outstanding voting securities of such third party or parties immediately following such transaction; (iv) (x) a "person" or "group" (as such terms are defined in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934, as amended) other than the Owner Affiliates becomes the "beneficial owner" directly or indirectly of 25% or more of the member interest in PAA GP Holdings LLC, a Delaware limited liability company and the general partner of PAGP ("PAGP GP"), and (y) the member interest beneficially owned by such "person" or "group" exceeds the aggregate member interest in PAGP GP beneficially owned, directly or indirectly, by the Owner Affiliates; (v) any Person (other than PAGP, the Partnership or their respective affiliates), including any partnership, limited partnership, syndicate or other "person" or "group," becomes the beneficial owner, directly or indirectly, of 50% or more of the membership interest in the Company or 50% or more of the outstanding limited partnership interests of PAGP; or (vi) any Person (other than PAGP or its wholly owned subsidiaries), including any partnership, limited partnership, syndicate or other "person" or "group," becomes the beneficial owner, directly or indirectly, of 50% or more of the membership interest in PAGP GP.

As used herein, the term "Owner Affiliates" shall mean KAFU Holdings, L.P. and its affiliates, EMG Investment, LLC and its affiliates, Oxy Holding Company (Pipeline), Inc. and its affiliates, Mark Strome and his affiliates, Windy, LLC and its affiliates, PAGP and its affiliates, Jay Chernosky, Kipp PAA Trust, Paul Riddle, Russell Clingman, David Humphreys and Philip Trinder.

The phrase "Termination for Cause" shall mean severance of your employment with the Company or its Affiliates based on your (i) failure to perform the duties and responsibilities of your position at an acceptable level as reasonably determined in good faith by the CEO of the Company, (ii) conviction of or guilty plea to the committing of an act or acts constituting a felony under the laws of the United States or any state thereof (or Canada or any province thereof) or any misdemeanor involving moral turpitude, or (iii) violation of the Company's Code of Business Conduct (unless waived in accordance with the terms thereof), in the case of clauses (i) and (iii), with the specific failure or violation described to you in writing.

Terms used herein that are not defined herein shall have the meanings set forth in the Plan or, if not defined in the Plan, in the Sixth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., as amended (the “Partnership Agreement”).

This award is intended to either (i) qualify as a “short-term deferral” under Section 409A of the Internal Revenue Code of 1986, as amended, or (ii) comply with the provisions of Section 409A. If it is determined that any payments or benefits to be made or provided under this Agreement do not comply with Section 409A, the parties agree to amend this Agreement or take such other actions as reasonably necessary or appropriate to comply with Section 409A while preserving the economic agreement of the parties.

By signing below, you agree that the Phantom Units and DERs granted hereunder are governed by the terms of the Plan. Copies of the Plan and the Partnership Agreement are available upon request.

In order for this grant to be effective you must designate a beneficiary that will be entitled to receive any benefits payable under this grant in the event of your death. Unless you indicate otherwise by checking the appropriate box the named beneficiaries on this form will serve as your beneficiaries for all previous LTIP grants. Please execute and return a copy of this grant letter to me and retain a copy for your records

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:______________________________
Name:
Title:

Beneficiary Designation

Primary Beneficiary Name	Relationship	Percent (Must total 100%)
Secondary Beneficiary Name	Relationship	Percent (Must total 100%)

Check this box only if designation does not apply to prior grants

____
[name]

Units: [amount]______

Dated: _______________________

Exhibit 12.1

STATEMENT OF COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in millions, except ratio data)

	Six Months Ended June 30,	Year Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**	**2012**
EARNINGS (1)						
Pre-tax income from continuing operations before noncontrolling interests and income from equity investees	$ 588	$ 560	$ 823	$ 1,449	$ 1,426	$ 1,143
add: Fixed charges	304	588	548	457	424	380
add: Distributed income of equity investees	136	216	214	105	55	40
add: Amortization of capitalized interest	3	7	6	4	3	2
less: Capitalized interest	(15)	(47)	(57)	(48)	(38)	(36)
Total Earnings	$ 1,016	$ 1,324	$ 1,534	$ 1,967	$ 1,870	$ 1,529
FIXED CHARGES (1)						
Interest expensed and capitalized	$ 271	$ 524	$ 495	$ 410	$ 381	$ 346
Portion of rent expense related to interest (33.33%)	33	64	53	47	43	34
Total Fixed Charges	$ 304	$ 588	$ 548	$ 457	$ 424	$ 380
RATIO OF EARNINGS TO FIXED CHARGES (2)	3.35x	2.25x	2.80x	4.30x	4.41x	4.03x

(1) For purposes of computing the ratio of earnings to fixed charges, “earnings” consists of pre-tax income from continuing operations before income from equity investees plus fixed charges (excluding capitalized interest), distributed income of equity investees and amortization of capitalized interest. “Fixed charges” represents interest incurred (whether expensed or capitalized), amortization of debt expense (including discounts and premiums relating to indebtedness) and the portion of rental expense on leases deemed to be the equivalent of interest.

(2) Ratios may not recalculate due to rounding.

EXHIBIT 31.1

CERTIFICATION

I, Greg L. Armstrong, certify that:

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

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

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

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

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 8, 2017

/s/ Greg L. Armstrong

Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Al Swanson, certify that:

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

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

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

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

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 8, 2017

/s/ Al Swanson

Al Swanson
Chief Financial Officer

EXHIBIT 32.1

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

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

(i) the accompanying report on Form 10-Q for the period ended June 30, 2017 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ Greg L. Armstrong

Name: Greg L. Armstrong
Date: August 8, 2017

EXHIBIT 32.2

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

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

(i) the accompanying report on Form 10-Q for the period ended June 30, 2017 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ Al Swanson

Name: Al Swanson

Date: August 8, 2017