PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
November 08, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2016

OR

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

Commission File Number: 1-14569

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

Delaware	76-0582150
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
333 Clay Street, Suite 1600, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 646-4100
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
ý Yes o No

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

Non-accelerated filer o (Do not check if a smaller reporting company)

Smaller reporting company o

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

As of November 1, 2016, there were 412,962,773 Common Units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	September 30, 2016 (unaudited)	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$31	$27
Trade accounts receivable and other receivables, net	1,946	1,785
Inventory	1,258	916
Other current assets	538	241
Total current assets	3,773	2,969
PROPERTY AND EQUIPMENT	16,103	15,654
Accumulated depreciation	(2,292)	(2,180)
Property and equipment, net	13,811	13,474
OTHER ASSETS		
Goodwill	2,353	2,405
Investments in unconsolidated entities	2,216	2,027
Linefill and base gas	899	898
Long-term inventory	146	129
Other long-term assets, net	309	386
Total assets	$23,507	$22,288
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$2,280	$2,038
Short-term debt	1,384	999
Other current liabilities	413	370
Total current liabilities	4,077	3,407
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discounts and debt issuance costs	9,130	9,698
Other long-term debt	504	677
Other long-term liabilities and deferred credits	722	567
Total long-term liabilities	10,356	10,942
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS' CAPITAL		
Series A preferred unitholders (63,126,331 units outstanding)	1,508	—

Common unitholders (408,107,646 and 397,727,624 units outstanding, respectively)	7,240	7,580
General partner	268	301
Total partners' capital excluding noncontrolling interests	9,016	7,881
Noncontrolling interests	58	58
Total partners' capital	9,074	7,939
Total liabilities and partners' capital	$23,507	$22,288

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$4,876	$5,247	$13,344	$17,225
Transportation segment revenues	159	172	482	538
Facilities segment revenues	135	132	405	393
Total revenues	5,170	5,551	14,231	18,156
COSTS AND EXPENSES				
Purchases and related costs	4,429	4,701	12,000	15,591
Field operating costs	289	348	893	1,111
General and administrative expenses	70	60	210	217
Depreciation and amortization	33	107	351	319
Total costs and expenses	4,821	5,216	13,454	17,238
OPERATING INCOME	349	335	777	918
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	46	45	133	134
Interest expense (net of capitalized interest of $11, $14, $37 and $42, respectively)	(113)	(109)	(339)	(320)
Other income/(expense), net	17	(4)	46	(7)
INCOME BEFORE TAX	299	267	617	725
Current income tax expense	(4)	(11)	(45)	(72)
Deferred income tax benefit/(expense)	3	(6)	30	6
NET INCOME	298	250	602	659
Net income attributable to noncontrolling interests	(1)	(1)	(3)	(2)
NET INCOME ATTRIBUTABLE TO PAA	$297	$249	$599	$657
BASIC NET INCOME PER COMMON UNIT (NOTE 3):				
Net income allocated to common unitholders — Basic	$162	$98	$110	$211
Basic weighted average common units outstanding	401	398	399	393
Basic net income per common unit	$0.40	$0.25	$0.27	$0.54
Net income allocated to common unitholders — Diluted	$162	$98	$110	$211
Diluted weighted average common units outstanding	402	399	400	395
Diluted net income per common unit	$0.40	$0.24	$0.27	$0.53

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
Net income	$298	$250	$602	$659
Other comprehensive loss	(45)	(311)	—	(518)
Comprehensive income/(loss)	253	(61)	602	141
Comprehensive income attributable to noncontrolling interests	(1)	(1)	(3)	(2)
Comprehensive income/(loss) attributable to PAA	$252	$(62)	$599	$139

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

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

	Derivative Instruments	Translation Adjustments	Total
	(unaudited)		
Balance at December 31, 2015	$ (203)	$ (878)	$(1,081)
Reclassification adjustments	7	—	7
Deferred loss on cash flow hedges	(178)	—	(178)
Currency translation adjustments	—	171	171
Total period activity	(171)	171	—
Balance at September 30, 2016	$ (374)	$ (707)	$(1,081)

	Derivative Instruments	Translation Adjustments	Total
	(unaudited)		
Balance at December 31, 2014	$ (159)	$ (308)	$(467)
Reclassification adjustments	(21)	—	(21)
Deferred loss on cash flow hedges	(28)	—	(28)
Currency translation adjustments	—	(469)	(469)
Total period activity	(49)	(469)	(518)
Balance at September 30, 2015	$ (208)	$ (777)	$(985)

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

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

	Nine Months Ended September 30,	
	2016	2015
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$602	$659
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	351	319
Equity-indexed compensation expense	40	27
Inventory valuation adjustments	3	25
Deferred income tax benefit	(30)	(6)
(Gain)/loss on foreign currency revaluation	1	(20)
Settlement of terminated interest rate hedging instruments	(50)	(48)
Change in fair value of Preferred Distribution Rate Reset Option (Note 9)	(42)	—
Equity earnings in unconsolidated entities	(133)	(134)
Distributions from unconsolidated entities	151	159
Other	13	(5)
Changes in assets and liabilities, net of acquisitions	(264)	246
Net cash provided by operating activities	642	1,222
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(282)	(104)
Investments in unconsolidated entities	(171)	(213)
Additions to property, equipment and other	(1,030)	(1,617)
Cash paid for purchases of linefill and base gas	(7)	(131)
Proceeds from sales of assets	638	4
Other investing activities	(2)	(8)
Net cash used in investing activities	(854)	(2,069)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) under commercial paper program (Note 7)	(617)	151
Net borrowings under senior secured hedged inventory facility (Note 7)	424	—
Proceeds from the issuance of senior notes	—	998
Repayments of senior notes (Note 7)	(175)	(549)
Net proceeds from the sale of Series A preferred units (Note 8)	1,569	—
Net proceeds from the sale of common units (Note 8)	283	1,099
Contributions from general partner	39	23
Distributions paid to common unitholders (Note 8)	(835)	(802)
Distributions paid to general partner (Note 8)	(464)	(436)
Other financing activities	(12)	(15)
Net cash provided by financing activities	212	469
Effect of translation adjustment on cash	4	(3)

Net increase/(decrease) in cash and cash equivalents	4	(381)
Cash and cash equivalents, beginning of period	27	403
Cash and cash equivalents, end of period	$ 31	$ 22
Cash paid for:		
Interest, net of amounts capitalized	$ 313	$ 287
Income taxes, net of amounts refunded	$ 78	$ 43

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

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

	Limited Partners					
	Series A Preferred Unitholders	Common Unitholders	General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	(unaudited)					
Balance at December 31, 2015	$—	$ 7,580	$ 301	$ 7,881	$ 58	$7,939
Net income	—	209	390	599	3	602
Cash distributions to partners	—	(835)	(464)	(1,299)	(3)	(1,302)
Sale of Series A preferred units	1,509	—	33	1,542	—	1,542
Sale of common units	—	283	6	289	—	289
Other	(1)	3	2	4	—	4
Balance at September 30, 2016	$1,508	$ 7,240	$ 268	$ 9,016	$ 58	$9,074

	Limited Partners				
	Common Unitholders	General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	(unaudited)				
Balance at December 31, 2014	$7,793	$ 340	$ 8,133	$ 58	$8,191
Net income	215	442	657	2	659
Cash distributions to partners	(802)	(436)	(1,238)	(2)	(1,240)
Sale of common units	1,099	22	1,121	—	1,121
Other comprehensive loss	(507)	(11)	(518)	—	(518)
Other	1	2	3	—	3
Balance at September 30, 2015	$7,799	$ 359	$ 8,158	$ 58	$8,216

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

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

Note 1—Organization and Basis of Consolidation and Presentation

Organization

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

We own and operate midstream energy infrastructure and provide logistics services 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 2% 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, AAP also owns all of our incentive distribution rights (“IDRs”). 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 member of GP LLC, and at September 30, 2016, owned an approximate 42% limited partner interest in AAP. PAA GP Holdings LLC (“GP Holdings”) is PAGP’s general partner.

GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and personnel are employed by our subsidiary, Plains Midstream Canada ULC (“PMC”). References to our “general partner,” as the context requires, include any or all of PAA GP, AAP and GP LLC.

Simplification Agreement

On July 11, 2016, PAA, PAGP, AAP, PAA GP, GP LLC and GP Holdings entered into a Simplification Agreement pursuant to which, upon closing, in exchange for the issuance by PAA to AAP of approximately 245.5 million common units representing limited partner interests in PAA and the assumption by PAA of AAP’s outstanding debt, AAP will contribute the IDRs to PAA and PAA GP’s 2% economic general partner interest in PAA will be converted into a non-economic general partner interest in PAA. Following the closing of the transactions contemplated by the Simplification Agreement, which is expected to occur on November 15, 2016, both PAA and PAGP will continue to be publicly traded. See Note 15 for further discussion of this transaction.

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Definitions

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

AOCI	=	Accumulated other comprehensive income/(loss)
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
DERs	=	Distribution equivalent rights
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
MLP	=	Master limited partnership
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 2015 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. 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. Such reclassifications include \$2 million and \$7 million reclassified from “Depreciation and amortization” to “Interest expense, net” in our accompanying Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2015, respectively, due to the retrospective application of revised debt issuance costs guidance issued by the FASB, which we adopted during the fourth quarter of 2015. These reclassifications do not affect net income attributable to PAA. The condensed consolidated balance sheet data as of December 31, 2015 was derived from audited financial statements, but does not include all disclosures required by GAAP. The results of operations for the three and nine months ended September 30, 2016 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.

Income Allocation

Net income for partners' capital presentation purposes is allocated in accordance with our partnership agreement. Our general partner and common unitholders are allocated income based on their respective partnership percentages, after giving effect to income allocations for (i) incentive distributions, if any, to our general partner (the holder of the IDRs pursuant to our partnership agreement) for distributions declared and paid following the close of each quarter and (ii) cash distributions to our preferred unitholders. In accordance with our partnership agreement, our preferred unitholders are not allocated income for paid-in-kind distributions.

For purposes of determining basic and diluted net income per common unit, income is allocated as prescribed in FASB guidance for calculating earnings per unit including application of the two-class method for MLPs. See Note 3 for additional information.

Note 2—Recent Accounting Pronouncements

Except as discussed below and in our 2015 Annual Report on Form 10-K, there have been no new accounting pronouncements that have become effective or have been issued during the nine months ended September 30, 2016 that are of significance or potential significance to us.

In February 2016, the FASB issued guidance that revises the current accounting model for leases. The most significant changes are the clarification of the definition of a lease and required lessee recognition on the balance sheet of lease assets and liabilities with lease terms of more than 12 months, including extensive quantitative and qualitative disclosures. This guidance will become effective for interim and annual periods beginning after December 15, 2018, with a modified retrospective application required. Early adoption is permitted, including adoption in an interim period. We expect to adopt this guidance on January 1, 2019. We are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations and cash flows. Although our evaluation is ongoing, we do expect that the adoption will impact our financial statements as the standard requires the recognition on the balance sheet of a right of use asset and corresponding lease liability. We are currently analyzing our contracts to determine whether they contain a lease under the revised guidance and have not quantified the amount of the asset and liability that will be recognized on our consolidated balance sheet.

In March 2016, the FASB issued guidance to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification of certain related payments on the statement of cash flows. This guidance will become effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. We expect to adopt this guidance on January 1, 2017, and do not anticipate that our adoption will have a material impact on our financial position, results of operations or cash flows.

In June 2016, the FASB issued new guidance for the accounting for credit losses on certain financial instruments. This guidance will become effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted by one year. We expect to adopt this guidance on January 1, 2020, and we are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations and cash flows.

In August 2016, the FASB issued guidance relating to the classification and presentation of eight specific cash flow issues. This guidance will become effective for interim and annual periods beginning after December 15, 2018, with early adoption permitted. We plan to early adopt this guidance during the fourth quarter of 2016, and we do not currently expect that our adoption will impact our statement of cash flows.

Note 3—Net Income Per Common Unit

Basic and diluted net income per common unit is determined pursuant to the two-class method for MLPs as prescribed in FASB guidance. The two-class method is an earnings allocation formula that is used to determine earnings to our general partner, limited partners and participating securities according to distributions pertaining to the current period’s net income and participation rights in undistributed earnings. Under this method, all earnings are allocated to our preferred unitholders, general partner, common unitholders and participating securities based on their respective rights to receive distributions, regardless of whether those earnings would actually be distributed during a particular period from an economic or practical perspective.

We calculate basic and diluted net income per common unit by dividing net income attributable to PAA (after deducting the amount allocated to the preferred unitholders, the general partner's interest, IDRs and participating securities) by the basic and diluted weighted-average number of common units outstanding during the period. Participating securities include LTIP awards that have vested DERs, which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

Diluted net income 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. When applying the if-converted method prescribed by FASB guidance, the possible conversion of our Series A preferred units was excluded from the calculation of diluted net income per common unit for the three and nine months ended September 30, 2016 as the effect was antidilutive. See Note 8 to our Condensed Consolidated Financial Statements for additional information regarding our Series A preferred units. Our LTIP awards that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed

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to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2015 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 per common unit (in millions, except per unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Basic Net Income per Common Unit				
Net income attributable to PAA	$297	$249	$599	$657
Distributions to Series A preferred units [1]	(33)	—	(88)	—
Distributions to general partner [1]	(102)	(154)	(412)	(454)
Distributions to participating securities [1]	(1)	(1)	(3)	(4)
Undistributed loss allocated to general partner [1]	1	4	14	12
Net income allocated to common unitholders in accordance with application of the two-class method for MLPs	$162	$98	$110	$211
Basic weighted average common units outstanding	401	398	399	393
Basic net income per common unit	$0.40	$0.25	$0.27	$0.54
Diluted Net Income per Common Unit				
Net income attributable to PAA	$297	$249	$599	$657
Distributions to Series A preferred units [1]	(33)	—	(88)	—
Distributions to general partner [1]	(102)	(154)	(412)	(454)
Distributions to participating securities [1]	(1)	(1)	(3)	(4)
Undistributed loss allocated to general partner [1]	1	4	14	12
Net income allocated to common unitholders in accordance with application of the two-class method for MLPs	$162	$98	$110	$211
Basic weighted average common units outstanding	401	398	399	393
Effect of dilutive securities: Weighted average LTIP units	1	1	1	2
Diluted weighted average common units outstanding	402	399	400	395
Diluted net income per common unit	$0.40	$0.24	$0.27	$0.53

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

Pursuant to the terms of our partnership agreement, the general partner’s incentive distribution is limited to a percentage of available cash, which, as defined in our partnership agreement, is net of reserves deemed appropriate. As such, IDRs are not allocated undistributed earnings or distributions in excess of earnings in the calculation of net income per common unit. If, however, undistributed earnings were allocated to our IDRs beyond amounts distributed to them under the terms of our partnership agreement, basic and diluted net income per common unit as reflected in the table above would not have been impacted, as we did not have undistributed earnings for any of the periods presented.

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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 September 30, 2016 and December 31, 2015, we had received $62 million and $88 million, respectively, of advance cash payments from third parties to mitigate credit risk. We also received $103 million and $36 million as of September 30, 2016 and December 31, 2015, 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 such 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 September 30, 2016 and December 31, 2015, 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 and $4 million at September 30, 2016 and December 31, 2015, respectively. 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):

	September 30, 2016				December 31, 2015			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)
Inventory								
Crude oil	20,494	barrels	$ 879	$ 42.89	16,345	barrels	$ 608	$ 37.20
NGL	21,087	barrels	321	$ 15.22	13,907	barrels	218	$ 15.68
Natural gas	15,116	Mcf	32	$ 2.12	22,080	Mcf	53	$ 2.40
Other	N/A		26	N/A	N/A		37	N/A
Inventory subtotal			1,258				916	
Linefill and base gas								
Crude oil	12,215	barrels	712	$ 58.29	12,298	barrels	713	$ 57.98
NGL	1,490	barrels	46	$ 30.87	1,348	barrels	44	$ 32.64
Natural gas	30,812	Mcf	141	$ 4.58	30,812	Mcf	141	$ 4.58
Linefill and base gas subtotal			899				898	
Long-term inventory								
Crude oil	3,428	barrels	124	$ 36.17	3,417	barrels	106	$ 31.02
NGL	1,418	barrels	22	$ 15.51	1,652	barrels	23	$ 13.92
Long-term inventory subtotal			146				129	
Total			$ 2,303				$ 1,943	

(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.

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Note 6—Goodwill

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

	Transportation	Facilities	Supply and Logistics	Total
Balance at December 31, 2015	$ 815	$ 1,087	$ 503	$ 2,405
Foreign currency translation adjustments	12	5	2	19
Dispositions and reclassifications to assets held for sale	(15)	(56)	—	(71)
Balance at September 30, 2016	$ 812	$ 1,036	$ 505	$ 2,353

We completed our annual goodwill impairment test as of June 30, 2016 and determined that there was no impairment of goodwill.

Note 7—Debt

Debt consisted of the following (in millions):

	September 30, 2016	December 31, 2015
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 1.3% and 1.1%, respectively (1)	$ 256	$ 696
Senior secured hedged inventory facility, bearing a weighted-average interest rate of 1.5% and 1.4%, respectively (1)	725	300
Senior notes:		
6.13% senior notes due January 2017	400	—
Other	3	3
Total short-term debt	1,384	999
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $70 and $77, respectively	9,130	9,698
Commercial paper notes, bearing a weighted-average interest rate of 1.3% and 1.1%, respectively (2)	500	672
Other	4	5
Total long-term debt	9,634	10,375
Total debt (3)	$ 11,018	$ 11,374

(1) We classified these commercial paper notes and credit facility borrowings as short-term as of September 30, 2016 and December 31, 2015, 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 September 30, 2016 and December 31, 2015, we 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 under our credit facilities.

(3) Our fixed-rate senior notes (including current maturities) had a face value of approximately $9.6 billion and $9.8 billion as of September 30, 2016 and December 31, 2015, respectively. We estimated the aggregate fair value of these notes as of September 30, 2016 and December 31, 2015 to be approximately $9.7 billion and $8.6 billion, respectively. Our fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near the end of the

reporting period. We estimate that the carrying value of outstanding borrowings under our credit facilities and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities and commercial paper program are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

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Credit Facilities

In August 2016, we extended the maturity dates of our senior unsecured revolving credit facility, senior secured hedged inventory facility and 364-day credit facility to August 2021, August 2019 and August 2017, respectively.

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the nine months ended September 30, 2016 and 2015 were approximately $41.4 billion and $37.1 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $41.6 billion and $36.9 billion for the nine months ended September 30, 2016 and 2015, 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 September 30, 2016 and December 31, 2015, we had outstanding letters of credit of $47 million and $46 million, respectively.

Senior Notes Repayments

Our $175 million, 5.88% senior notes were repaid in August 2016. We utilized cash on hand and available capacity under our commercial paper program and credit facilities to repay these notes.

Note 8—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, 2015	—	397,727,624
Sale of Series A preferred units	61,030,127	—
Issuance of Series A preferred units in connection with in-kind distributions	2,096,204	—
Sale of common units	—	9,922,733
Issuance of common units under LTIP	—	457,289
Outstanding at September 30, 2016	63,126,331	408,107,646

	Limited Partners
	Common Units
Outstanding at December 31, 2014	375,107,793
Sale of common units	22,133,904
Issuance of common units under LTIP	485,927
Outstanding at September 30, 2015	397,727,624

Equity Offerings

Series A Preferred Unit Offering. On January 28, 2016 (the "Issuance Date"), we completed the private placement of approximately 61.0 million Series A preferred units representing limited partner interests in us for a cash purchase price of $26.25 per unit (the “Issue Price”).

The Series A preferred units are a new class of equity security that ranks senior to all classes or series of our equity securities with respect to distribution rights and rights upon liquidation. The holders of the Series A preferred units receive

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cumulative quarterly distributions, subject to customary antidilution adjustments, equal to $0.525 per unit ($2.10 per unit annualized). With respect to any quarter ending on or prior to December 31, 2017 (the “Initial Distribution Period”), we may elect to pay distributions on the Series A preferred units in additional preferred units, in cash or a combination of both. With respect to any quarter ending after the Initial Distribution Period, we must pay distributions on the Series A preferred units in cash.

The purchasers may convert their Series A preferred units into common units, generally on a one-for-one basis and subject to customary antidilution adjustments, at any time after the second anniversary of the Issuance Date (or prior to a liquidation), in whole or in part, subject to certain minimum conversion amounts. We may convert the Series A preferred units into common units at any time (but not more often than once per quarter) after the third anniversary of the Issuance Date, in whole or in part, subject to certain minimum conversion amounts, if the closing price of our common units is greater than 150% of the Issue Price for the preceding 20 trading days. The Series A preferred units will vote on an as-converted basis with our common units and will have certain other class voting rights with respect to any amendment to our partnership agreement that would adversely affect any rights, preferences or privileges of the Series A preferred units. In addition, upon certain events involving a change of control, the holders of the Series A preferred units may elect, among other potential elections, to convert the Series A preferred units to common units at the then applicable conversion rate.

For a period of 30 days following (a) the fifth anniversary of the Issuance Date of the Series A preferred units and (b) each subsequent anniversary of the Issuance Date, the holders of the Series A preferred units, acting by majority vote, may make a one-time election to reset the distribution rate to equal the then applicable rate of the ten-year U.S. Treasury plus 5.85% (the “Preferred Distribution Rate Reset Option”). The Preferred Distribution Rate Reset Option is accounted for as an embedded derivative. See Note 9 for additional information. If the holders of the Series A preferred units have exercised the Preferred Distribution Rate Reset Option, then, at any time following 30 days after the sixth anniversary of the Issuance Date, we may redeem all or any portion of the outstanding Series A preferred units in exchange for cash, common units (valued at 95% of the volume-weighted average price of the common units for a trading day period specified in our partnership agreement) or a combination of cash and common units at a redemption price equal to 110% of the Issue Price, plus any accrued and unpaid distributions.

Continuous Offering Program. During the nine months ended September 30, 2016, we issued an aggregate of approximately 9.9 million common units under our continuous offering program, generating proceeds of $289 million, including our general partner's proportionate capital contribution of $6 million, net of $2 million of commissions paid to our sales agents.

Distributions

Cash Distributions. The following table details the distributions paid in cash during or pertaining to the first nine months of 2016, net of reductions to the general partner’s incentive distributions (in millions, except per unit data):

Distribution Date	Distributions Common Unitholders	Distributions General Partner	Total	Distributions per common unit
November 14, 2016 [1]	$ 227	$ 101	$ 328	$ 0.55
August 12, 2016	$ 278	$ 155	$ 433	$ 0.70
May 13, 2016	$ 278	$ 155	$ 433	$ 0.70
February 12, 2016	$ 278	$ 155	$ 433	$ 0.70

(1) Payable to unitholders of record at the close of business on October 31, 2016 for the period July 1, 2016 through September 30, 2016.

In-Kind Distributions. On May 13, 2016, we issued 858,439 additional Series A preferred units in lieu of a cash distribution of $23 million. Such distribution was issued to Series A preferred unitholders of record as of April 29, 2016 and was prorated for the period beginning on January 28, 2016, the issuance date of the Series A preferred units, through March 31, 2016. On August 12, 2016, we issued 1,237,765 additional Series A preferred units in lieu of a cash distribution of $33 million.

On November 14, 2016, we will issue 1,262,522 additional Series A preferred units in lieu of a cash distribution of $33 million. Since the November 14, 2016 Series A preferred unit distribution was declared as payment-in-kind, this distribution payable was accrued to partners’ capital as of September 30, 2016 and thus had no net impact on the Series A preferred unitholders’ capital account.

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Noncontrolling Interests in Subsidiaries

As of September 30, 2016, noncontrolling interests in our subsidiaries consisted of a 25% interest in SLC Pipeline LLC.

Note 9—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 (i) manage our exposure to commodity price risk, as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange rate risk. Our commodity 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 September 30, 2016, net derivative positions related to these activities included:

- A net long position of 4.4 million barrels associated with our crude oil purchases, which was unwound ratably during October 2016 to match monthly average pricing.

- A net short time spread position of 3.1 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through December 2017.

- A crude oil grade spread position of 16.0 million barrels through December 2019. These derivatives allow us to lock in grade basis differentials.

- A net short position of 12.9 Bcf through July 2017 related to anticipated sales of natural gas inventory.

- A net short position of 34.7 million barrels through December 2019 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 September 30, 2016, our PLA hedges included a long call option position of 1.1 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 September 30, 2016, we had a long natural gas position of 31.6 Bcf of which 27.7 Bcf hedges our natural gas processing needs through December 2017. The

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remaining 3.9 Bcf of our natural gas position hedges natural gas required for operational needs through December 2018. We also had a short propane position of 5.1 million barrels through December 2017, a short butane position of 1.6 million barrels through December 2017 and a short WTI position of 0.7 million barrels through December 2017. In addition, we had a long power position of 0.4 million megawatt hours, which hedges a portion of our power supply requirements at our Canadian natural gas processing and fractionation plants through December 2018.

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 interest rate risk associated with anticipated and outstanding 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. As of September 30, 2016, AOCI includes deferred losses of $353 million that relate to open and terminated interest rate derivatives that were designated as cash flow hedges. The majority of the terminated interest rate derivatives were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the terms of the hedged debt instruments.

We have entered into forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted interest payments through 2049. The following table summarizes the terms of our forward starting interest rate swaps as of September 30, 2016 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	4/13/2017	2.02 %	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/15/2017	3.14 %	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/15/2018	3.20 %	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/14/2019	2.83 %	Cash flow hedge

During June 2016, we made a cash payment of approximately $52 million in connection with the termination of eight forward starting interest rate swaps that had an aggregate notional amount of $200 million and an average fixed rate of 3.06%. In conjunction with this termination, a loss of approximately $50 million was deferred to AOCI, and a loss of approximately $2 million was immediately recognized in interest expense attributable to the determination that a previously forecasted interest payment is now considered probable of not occurring.

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 and forwards.

As of September 30, 2016, 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 September 30, 2016 (in millions):

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		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2016	$222	$291	$1.00 - $1.31
	2017	$51	$67	$1.00 - $1.31
Forward exchange contracts that exchange USD for CAD:				
	2016	$273	$355	$1.00 - $1.30
	2017	$126	$164	$1.00 - $1.30

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 September 30, 2016, the fair value of this embedded derivative was a liability of approximately $18 million. We recognized gains of approximately $17 million and $42 million during the three and nine months ended September 30, 2016, respectively, due to changes in fair value during the periods. See Note 8 for additional information regarding our Series A preferred units and the Preferred Distribution Rate Reset Option.

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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 September 30, 2016			Three Months Ended September 30, 2015		
Location of Gain/(Loss)	Derivatives in Hedging Relationships	Derivatives Not Designated as a Hedge [1]	Total	Derivatives in Hedging Relationships	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives						
Supply and Logistics segment revenues	$1	$ 10	$11	$42	$ 14	$56
Transportation segment revenues	—	1	1	—	2	2
Field operating costs	—	(2)	(2)	—	(9)	(9)
Interest Rate Derivatives						
Interest expense, net	(2)	—	(2)	(4)	—	(4)
Foreign Currency Derivatives						
Supply and Logistics segment revenues	—	(1)	(1)	—	(9)	(9)
Preferred Distribution Rate Reset Option						
Other income/(expense), net	—	17	17	—	—	—
Total Gain/(Loss) on Derivatives Recognized in Net Income	$(1)	$ 25	$24	$38	$ (2)	$36

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Location of Gain/(Loss)	Nine Months Ended September 30, 2016 Derivatives in Hedging Relationships (1)	Nine Months Ended September 30, 2016 Derivatives Not Designated as a Hedge	Nine Months Ended September 30, 2016 Total	Nine Months Ended September 30, 2015 Derivatives in Hedging Relationships (1)	Nine Months Ended September 30, 2015 Derivatives Not Designated as a Hedge	Nine Months Ended September 30, 2015 Total
Commodity Derivatives						
Supply and Logistics segment revenues	$1	$ (118)	$(117)	$30	$ 24	$54
Transportation segment revenues	—	4	4	—	6	6
Field operating costs	—	(2)	(2)	—	(11)	(11)
Interest Rate Derivatives						
Interest expense, net	(8)	—	(8)	(9)	—	(9)
Foreign Currency Derivatives						
Supply and Logistics segment revenues	—	4	4	—	(26)	(26)
Preferred Distribution Rate Reset Option						
Other income/(expense), net	—	42	42	—	—	—
Total Gain/(Loss) on Derivatives Recognized in Net Income	$(7)	$ (70)	$(77)	$21	$ (7)	$14

(1) During the nine months ended September 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. During the nine months ended September 30, 2015, we reclassified a loss of approximately $4 million from AOCI to Interest expense, net due to an anticipated hedged transaction being probable of not occurring.

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The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of September 30, 2016 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 1		
Interest rate derivatives			Other current liabilities	$ (72)
			Other long-term liabilities and deferred credits	(103)
Total derivatives designated as hedging instruments		$ 1		$ (175)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 77	Other current assets	$ (119)
	Other long-term liabilities and deferred credits	3	Other current liabilities	(10)
			Other long-term liabilities and deferred credits	(18)
Foreign currency derivatives	Other current liabilities	1	Other current liabilities	(4)
Preferred Distribution Rate Reset Option			Other long-term liabilities and deferred credits	(18)
Total derivatives not designated as hedging instruments		$ 81		$ (169)
Total derivatives		$ 82		$ (344)

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The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of December 31, 2015 (in millions):

	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 4	Other current assets	$ (2)
Interest rate derivatives	Other long-term assets, net	1	Other current liabilities	(17)
			Other long-term liabilities and deferred credits	(33)
Total derivatives designated as hedging instruments		$ 5		$ (52)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 265	Other current assets	$ (35)
	Other long-term assets, net	10	Other long-term assets, net	(1)
			Other current liabilities	(13)
			Other long-term liabilities and deferred credits	(1)
Foreign currency derivatives			Other current liabilities	(8)
Total derivatives not designated as hedging instruments		$ 275		$ (58)
Total derivatives		$ 280		$ (110)

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. As of September 30, 2016, we had a net broker receivable of $142 million (consisting of initial margin of $96 million increased by $46 million of variation margin that had been posted by us). As of December 31, 2015, we had a net broker payable of $156 million (consisting of initial margin of $91 million reduced by $247 million of variation margin that had been returned to us).

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

	September 30, 2016		December 31, 2015	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$82	$ (344)	$280	$ (110)
Netting adjustment	(123)	123	(38)	38
Cash collateral paid/(received)	142	—	(156)	—
Net position - asset/(liability)	$101	$ (221)	$86	$ (72)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$101	$ —	$76	$ —
Other long-term assets, net	—	—	10	—
Other current liabilities	—	(85)	—	(38)
Other long-term liabilities and deferred credits	—	(136)	—	(34)
	$101	$ (221)	$86	$ (72)

As of September 30, 2016, there was a net loss of $374 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 September 30, 2016, we expect to reclassify a net loss of $7 million to earnings in the next twelve months. The remaining deferred loss of $367 million is expected to be reclassified to earnings through 2049. A portion of these amounts is based on market prices as of September 30, 2016; 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Commodity derivatives, net	$—	$37	$—	$12
Interest rate derivatives, net	(20)	(85)	(178)	(40)
Total	$(20)	$(48)	$(178)	$(28)

At September 30, 2016 and December 31, 2015, 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 September 30, 2016				Fair Value as of December 31, 2015			
Recurring Fair Value Measures [1]	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	$(27)	$(40)	$1	$(66)	$126	$90	$11	$227
Interest rate derivatives	—	(175)	—	(175)	—	(49)	—	(49)
Foreign currency derivatives	—	(3)	—	(3)	—	(8)	—	(8)
Preferred Distribution Rate Reset Option	—	—	(18)	(18)	—	—	—	—
Total net derivative asset/(liability)	$(27)	$(218)	$(17)	$(262)	$126	$33	$11	$170

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(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 classified as an embedded derivative.

The fair value of our Level 3 physical commodity contracts is based on a valuation model utilizing broker-quoted forward commodity prices, and timing estimates, which involve management judgment. The significant unobservable inputs used in the fair value measurement of our Level 3 derivatives are forward prices obtained from brokers. A significant increase or decrease in these forward prices 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Beginning Balance	$(35)	$9	$11	$15

Gains for the period included in earnings	17	2	41	1
Settlements	—	(2)	(10)	(13)
Derivatives entered into during the period	1	2	(59)	8
Ending Balance	$(17)	$11	$(17)	$11
Change in unrealized gains included in earnings relating to Level 3 derivatives still held at the end of the period	$18	$4	$43	$9

Note 10—Related Party Transactions

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See Note 14 to our Consolidated Financial Statements included in Part IV of our 2015 Annual Report on Form 10-K for a complete discussion of our related party transactions.

Transactions with Oxy

As of September 30, 2016, Oxy owned approximately 12% of the limited partner interests in our general partner and had a representative on the board of directors of GP LLC. During the three and nine months ended September 30, 2016 and 2015, 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Revenues	$171	$187	$424	$745
Purchases and related costs [1]	$4	$(34)	$(46)	$112

(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):

	September 30, 2016	December 31, 2015
Trade accounts receivable and other receivables	$ 610	$ 405
Accounts payable	$ 587	$ 363

Note 11—Equity-Indexed Compensation Plans

We refer to the PAA LTIPs and AAP Management Units collectively as our “equity-indexed compensation plans.” For additional discussion of our equity-indexed compensation plans and awards, see Note 15 to our Consolidated Financial Statements included in Part IV of our 2015 Annual Report on Form 10-K.

During the third quarter of 2016, modifications were made to the vesting criteria of approximately 2.2 million PAA LTIP units to eliminate distribution performance thresholds, if any, greater than $0.70 per common unit per quarter, and provide that such units will vest based solely on the passage of time during the years 2017 to 2020. In addition, approximately 1.7 million PAA LTIP units were granted with a weighted average grant date fair value of $22.85 per unit.

Modifications were also made to the distribution performance thresholds of approximately 2.2 million unearned AAP Management Units such that the awards will become earned based on the attainment of PAA distribution levels between $2.20 and $2.40 per common unit, on an annualized basis, and additional performance conditions based on our distributable cash flow.

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.

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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 September 30, 2016, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident, as discussed further below) totaled $160 million, of which $57 million was classified as short-term and $103 million was classified as long-term. At December 31, 2015, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident) totaled $185 million, of which $81 million was classified as short-term and $104 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

September 30, 2016, we had recorded receivables totaling $79 million for amounts probable of recovery under insurance and from third parties under indemnification agreements, of which $57 million was reflected in “Trade accounts receivable and other receivables, net” and $22 million was reflected in “Other long-term assets, net” on our Condensed Consolidated Balance Sheets. At December 31, 2015, we had recorded $161 million of such receivables, of which $138 million was reflected in “Trade accounts receivable and other receivables, net” and $23 million was reflected in “Other long-term assets, net” on our Condensed Consolidated Balance Sheets.

In some cases, the actual cash expenditures associated with these liabilities may not occur for three years or longer. Our estimates used in determining these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing or future legal claims giving rise to additional liabilities. Therefore, although we believe that the reserve

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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, subject to continued shoreline monitoring. Our current “worst case” estimate of the amount of oil spilled, representing the maximum volume of oil that we believed could have been spilled based on relevant facts, data and information, is approximately 2,935 barrels.

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 Line 903 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. 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 pursued 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

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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 (four felony and six 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 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 persons that derive a significant portion of their income through commercial fishing and harvesting activities in the waters adjacent to Santa Barbara County or from businesses that are dependent on marine resources from Santa Barbara County, retail businesses located in historic downtown Santa Barbara, 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. 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, deny the allegations in these lawsuits and intend to respond 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 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, three 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 have been administratively consolidated into one action; the other 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 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 intend to respond 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 September 30, 2016, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $280 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. 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 expected number of days that monitoring services will be required, (ii) the duration of the natural resource damage assessment and the ultimate amount of damages determined, (iii) 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, (iv) the determination and calculation of fines and penalties, but excluding fines and penalties that are not probable and reasonably estimable and (v) 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 September 30, 2016, we had a remaining undiscounted gross liability of $87 million related to this event, of which approximately $47 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 September 30, 2016, we had collected, subject to customary reservations, $129 million out of the approximate $197 million of release costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of September 30, 2016, we have recognized a receivable of approximately $68 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 $48 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 substantially completed the clean-up and remediation efforts, excluding long-term site monitoring activities; however, we expect to make payments for additional costs associated with restoration and monitoring of the area, as well as natural resource damage assessment, legal, professional and regulatory costs, in addition to fines and penalties, during future periods.

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MP29 Release. On July 10, 2015, we experienced a crude oil release of approximately 100 barrels at our Pocahontas Pump Station near the border of Bond and Madison Counties in Illinois, approximately 40 miles from St. Louis, Missouri. The Pocahontas Station is part of the Capwood pipeline that runs from our Patoka Station to Wood River, Illinois. A portion of the released crude oil was contained within our Pocahontas facility, but some of the released crude oil entered a nearby waterway where it was contained with booms. On July 14, 2015, PHMSA issued a corrective action order requiring us to take various actions in response to the release, including remediation, reporting and other actions. As of December 18, 2015, we had submitted all requested information and reports required by the corrective action order and are currently awaiting PHMSA's comment or approval. On August 10, 2015, we received a Notice of Violation from the Illinois Environmental Protection Agency (the "Agency") alleging violations relating to the release and outlining the activities recommended by the Agency to resolve the alleged violations, including the completion of an investigation and various remediation activities. The Agency approved a work plan describing remediation activities proposed for remaining hydrocarbons at Pocahontas Station and affected waterways. Remediation activities under this work plan have effectively been completed, and on December 17, 2015, we entered into a Compliance Commitment Agreement with the Agency, which provides the framework for final completion and documentation of the remediation effort. On April 15, 2016, the Agency confirmed that all of the activities required by the Compliance Commitment Agreement had been completed and that the violations associated with the incident had been resolved. To date, no fines or penalties have been assessed in this matter; however, it remains possible that fines and penalties could be assessed in the future. In connection with this incident, we have also had one class action lawsuit filed against us in the United States District Court for the Southern District of Illinois, which was subsequently voluntarily dismissed by the plaintiff. We estimate that the aggregate total costs we have incurred or will incur with respect to this release will be less than $10 million.

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. PHMSA's compliance officer has recommended that we be assessed a civil penalty of $190,000. We have formally responded to PHMSA regarding this matter, but at this point we can provide no assurance regarding the final disposition of this matter or the final amount of any civil penalties.

Note 13—Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on measures including segment profit and maintenance capital investment. We define segment profit 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. Each of the items above 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 table reflects certain financial data for each segment (in millions):

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Three Months Ended September 30, 2016	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External customers	$ 159	$ 135	$ 4,876	$5,170
Intersegment [(1)]	242	147	3	392
Total revenues of reportable segments	$ 401	$ 282	$ 4,879	$5,562
Equity earnings in unconsolidated entities	$ 46	$ —	$ —	$46
Segment profit/(loss) [(2)] [(3)]	$ 261	$ 173	$ (6)	$428
Maintenance capital	$ 29	$ 15	$ 3	$47

Three Months Ended September 30, 2015	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External customers	$ 172	$ 132	$ 5,247	$5,551
Intersegment [(1)]	229	131	7	367
Total revenues of reportable segments	$ 401	$ 263	$ 5,254	$5,918
Equity earnings in unconsolidated entities	$ 45	$ —	$ —	$45
Segment profit [(2)] [(3)]	$ 254	$ 146	$ 87	$487
Maintenance capital	$ 34	$ 16	$ 2	$52

Nine Months Ended September 30, 2016	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External customers	$ 482	$ 405	$ 13,344	$14,231
Intersegment [(1)]	706	412	9	1,127
Total revenues of reportable segments	$ 1,188	$ 817	$ 13,353	$15,358
Equity earnings in unconsolidated entities	$ 133	$ —	$ —	$133
Segment profit [(2)] [(3)]	$ 760	$ 488	$ 13	$1,261
Maintenance capital	$ 86	$ 32	$ 10	$128

Nine Months Ended September 30, 2015	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External customers	$ 538	$ 393	$ 17,225	$18,156
Intersegment [(1)]	665	396	13	1,074
Total revenues of reportable segments	$ 1,203	$ 789	$ 17,238	$19,230
Equity earnings in unconsolidated entities	$ 134	$ —	$ —	$134
Segment profit [(2)] [(3)]	$ 681	$ 432	$ 258	$1,371
Maintenance capital	$ 101	$ 48	$ 5	$154

(1) 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. For further discussion, see “Analysis of Operating Segments” under Item 7 of our 2015 Annual Report on Form 10-K.

(2) Supply and Logistics segment profit includes interest expense (related to hedged inventory purchases) of $5 million and $1 million for the three months ended September 30, 2016 and 2015, respectively, and $10 million and $4 million for the nine months ended September 30, 2016 and 2015, respectively.

(3) The following table reconciles segment profit to net income attributable to PAA (in millions):

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Segment profit	$428	$487	$1,261	$1,371
Depreciation and amortization	(33)	(107)	(351)	(319)
Interest expense, net	(113)	(109)	(339)	(320)
Other income/(expense), net	17	(4)	46	(7)
Income before tax	299	267	617	725
Income tax expense	(1)	(17)	(15)	(66)
Net income	298	250	602	659
Net income attributable to noncontrolling interests	(1)	(1)	(3)	(2)
Net income attributable to PAA	$297	$249	$599	$657

Note 14—Acquisitions, Investments in Unconsolidated Entities, Dispositions and Impairments

Acquisitions. During the first nine months of 2016, we completed two acquisitions for cash consideration of $289 million. We did not recognize any goodwill related to these acquisitions. Included in these acquisitions was an integrated system of NGL assets in Western Canada from Westcoast Energy Inc., a unit of Spectra Energy, for cash consideration of approximately $204 million.

Investments in Unconsolidated Entities. In June 2016, we sold 50% of our investment in Cheyenne Pipeline LLC (“Cheyenne”), and in August 2016 we sold 50% of our investment in STACK Pipeline LLC (“STACK Pipeline”). As a result of these transactions, we now account for our remaining 50% equity interest in such entities under the equity method of accounting.

Dispositions and Divestitures. During the nine months ended September 30, 2016, we sold several non-core assets, including certain of our Gulf Coast pipelines and East Coast refined products terminals. In addition, we sold interests in Cheyenne and STACK Pipeline, as discussed above. In the aggregate, we recognized a net gain of approximately $99 million related to these transactions, which is included in "Depreciation and amortization" on our Condensed Consolidated Statement of Operations. Such amount is comprised of gains of approximately $155 million and losses of $56 million, including $15 million of impairment of goodwill that was included in a disposal group classified as held for sale prior to the closing of such transaction.

As of September 30, 2016, we classified approximately $275 million of assets as held for sale on our Condensed Consolidated Balance Sheet (in “Other current assets”) primarily related to definitive agreements to sell non-core assets, a majority of which are included in our Facilities segment. We expect the sales to be consummated in the fourth quarter of 2016 or the first half of 2017, subject to customary closing conditions, as applicable.

Impairments. During the second quarter of 2016, we recognized approximately $80 million of non-cash impairment losses on certain of our long-lived rail and other terminal assets included in our Facilities segment. Such impairment losses are reflected in “Depreciation and amortization” on our Condensed Consolidated Statement of Operations. The decline in demand for movements of crude oil by rail in the United States due to sustained unfavorable market conditions resulted in expected decreases in future cash flows for certain of our rail terminal assets, which was a triggering event that required us to assess the recoverability of our carrying value of such long-lived assets. As a result of this impairment review, we wrote off the portion of the carrying amount of these long-lived assets that exceeded their fair value. Our estimated fair values were based upon recent sales prices of comparable facilities, as well as management's expectation of the market values for such assets based on their industry experience. We consider such inputs to be a Level 3 input in the fair value hierarchy.

In addition, during the second quarter of 2016, we recognized a charge of approximately $18 million to "Depreciation and amortization" related to the write-off of the remaining book value of assets taken out of service.

Note 15—Simplification Transactions

On July 11, 2016, PAA, PAGP, AAP, PAA GP, GP LLC and GP Holdings entered into a Simplification Agreement pursuant to which, upon closing, in exchange for the issuance by PAA to AAP of approximately 245.5 million common units representing limited partner interests in PAA ("PAA Common Units") and the assumption by PAA of AAP's outstanding debt (as of September 30, 2016, approximately $603 million but expected to be approximately $641 million as of November 15,

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2016), AAP will contribute the IDRs to PAA and PAA GP's 2% economic general partner interest in PAA will be converted into a non-economic general partner interest in PAA. Following the closing of the transactions contemplated by the Simplification Agreement (the "Simplification Transactions"), which is expected to occur on November 15, 2016, both PAA and PAGP will continue to be publicly traded. PAA will be required to repay AAP's outstanding debt within two business days after the consummation of the Simplification Transactions.

Among other approvals, the terms of the Simplification Agreement and the Simplification Transactions were unanimously approved by a conflicts committee comprised of independent directors of the Board of Directors of GP LLC on behalf of PAA, and unanimously approved by the Board of Directors of GP Holdings on behalf of PAGP.

In addition to the terms described above, the Simplification Agreement also provides for the following:

- Under a unified governance structure, the Board of Directors of GP Holdings will have oversight responsibility over both PAA and PAGP. In addition, starting in 2018, PAGP Class A and Class B shareholders and PAA common and preferred unitholders will have the right to participate in the election of directors of GP Holdings whose terms expire. Under the current structure, PAA common unitholders are not eligible to participate in the election of directors of GP Holdings and PAGP Class A and Class B shareholders only participate in such elections following a reduction in ownership of the private general partner owner group to below 40%.

- In addition, similar to the current structure, for so long as each of EMG Investment, LLC (an affiliate of The Energy & Minerals Group), KAFU Holdings, L.P. (an affiliate of Kayne Anderson Investment Management Inc.) and Oxy Holding Company (Pipeline), Inc. (a subsidiary of Occidental Petroleum Corporation), together with their respective affiliates (together, the "Original Designating Parties"), own at least a 10% interest in the initial outstanding AAP units (i.e., as of the closing of the Simplification Transactions), such party will continue to be entitled to designate one director to the Board of Directors of GP Holdings. The calculation of such qualifying interest will include, in addition to any PAGP Class A shares owned by an Original Designating Party or its affiliates, any PAA common units received by such Original Designating Party of its affiliates in connection with their exercise of the Redemption Right (defined below).

- AAP will execute a reverse split to adjust the number of AAP units such that the number of outstanding AAP Class A units (assuming the conversion of AAP Class B units into AAP Class A units) equals the number of PAA Common Units received by AAP at the closing of the Simplification Transactions. Simultaneously, PAGP will execute 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. As a result of these reverse splits, each PAGP Class A share will correspond, on a one-to-one basis, to an underlying PAA Common Unit held by AAP which is attributable to PAGP's ownership in AAP.

- Holders of AAP Class A units other than PAGP and GP LLC will continue to have the right to exchange their AAP Class A units (together with the corresponding PAGP Class B shares and, if applicable, GP Holdings company units) for PAGP Class A shares on a one-for-one basis or, alternatively, to redeem such ownership and related rights for their proportionate share of PAA Common Units held by AAP, subject to certain limitations (the "Redemption Right"). Upon any such redemption, the holders of AAP Class A units receiving PAA Common Units will have registration rights with respect to such PAA Common Units.

Pursuant to the terms of the Simplification Agreement, AAP agreed that if (i) the closing of the Simplification Transactions does not occur prior to the record date for PAA's distribution of available cash in respect of the third quarter of 2016 and (ii) the amount of such distribution is below a quarterly level of $0.70 per common unit, AAP will borrow funds under its existing credit agreement as necessary to make a special "true-up" distribution to AAP's unitholders that, when added to the distributions to be paid to AAP in respect of its indirect 2% general partner interest and IDRs, equals the total distribution such unitholders would have received had the closing of the Simplification Transactions occurred prior to such third quarter record date. As the Simplification Transactions did not close prior to the PAA third quarter distribution record date of October 31, 2016 and PAA declared a quarterly distribution of $0.55 per common unit for its third quarter distribution, it is currently estimated that the incremental borrowings that will be made by AAP will be approximately $33 million.

The consummation of the matters contemplated by the Simplification Agreement is subject to customary closing conditions and may be terminated under certain conditions. On September 26, 2016, PAGP announced November 15, 2016 as the date for the special meeting of its shareholders to consider and vote upon a proposal to approve the Simplification Transactions. We currently expect that the closing of the Simplification Transactions will take place on November 15, 2016.

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

Pro Forma Results

Selected PAA historical consolidated financial information has been adjusted below to give effect to pro forma events that are directly attributable to the proposed Simplification Transactions and are based upon currently available information and certain estimates and assumptions made by management. Therefore, the unaudited pro forma amounts presented below are not necessarily reflective of the results of operations or financial position of PAA that would have resulted had the Simplification Transactions been consummated as of the dates indicated, and are not necessarily indicative of the future results of operations or the future financial position of PAA following completion of the proposed Simplification Transactions.

Selected unaudited pro forma results of operations for the three and nine months ended September 30, 2016 are presented below giving effect to the Simplification Transactions as if they had occurred on January 1, 2016 (amounts in millions, except per unit data):

	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2016
Net income attributable to PAA	$ 294	$ 589
Basic net income per common unit	$ 0.40	$ 0.77
Diluted net income per common unit	$ 0.40	$ 0.77

Selected unaudited pro forma balance sheet amounts as of September 30, 2016 are presented below giving effect to the Simplification Transactions as if they had occurred on September 30, 2016 (amounts in millions):

	As of September 30, 2016
LONG-TERM LIABILITIES	
Other long-term debt, net of unamortized debt issuance costs	$ 1,114
PARTNERS’ CAPITAL	
Common unitholders	$ 6,898
General partner	$ —
Total partners’ capital	$ 8,464

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical Consolidated Financial Statements and accompanying notes and Management's Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2015 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 nine months of 2016, we recognized net income attributable to PAA of $599 million as compared to net income attributable to PAA of $657 million recognized during the first nine months of 2015. Our financial results for the comparative periods were impacted by:

- Lower operating results from our Supply and Logistics segment, primarily due to less favorable crude oil and NGL market conditions;

- Higher results from (i) our Transportation segment, as the comparative 2015 period was negatively impacted by costs associated with the Line 901 incident that occurred in May 2015, and (ii) our Facilities segment due to contributions from recently completed acquisitions and capital expansion projects;

- Higher depreciation and amortization expense primarily resulting from (i) our recently completed capital expansion projects, (ii) impairment losses related to certain of our rail and other terminal assets and (iii)

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assets taken out of service, all partially offset by net gains related to non-core assets sales and joint venture formations completed during the 2016 period;

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

- Gains of approximately $42 million recognized during the nine months ended September 30, 2016 related to the mark-to-market impact of our Preferred Distribution Rate Reset Option; and

- Lower income tax expense primarily due to lower taxable earnings from our Canadian operations and the impact from the cumulative revaluation of Canadian net deferred tax liabilities resulting from an Alberta, Canada provincial tax rate increase enacted during the comparative 2015 period.

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

We invested $1.065 billion in midstream infrastructure projects during the nine months ended September 30, 2016, with a targeted expansion capital plan for the full year of 2016 of approximately $1.425 billion. Additionally, in August 2016, we completed the acquisition of an integrated system of NGL assets in Western Canada from Westcoast Energy Inc., a unit of Spectra Energy, for cash consideration of approximately $204 million. To fund such capital activities, we completed (i) the private placement of approximately 61.0 million Series A preferred units for net proceeds of approximately $1.6 billion, including our general partner's proportionate capital contribution, (ii) the sale of approximately 9.9 million common units for net proceeds of $289 million and (iii) the sale of various assets for net proceeds of approximately $550 million, primarily related to our planned non-core asset sales initiative, as well as our sale of 50% of our investment in each of Cheyenne Pipeline LLC and STACK Pipeline LLC.

Additionally, we paid approximately $1.3 billion of cash distributions to our common unitholders and general partner during the nine months ended September 30, 2016, and we declared a quarterly distribution of $0.55 per common unit to be paid on November 14, 2016.

Furthermore, in July 2016, PAA, PAGP, AAP, PAA GP, GP LLC and GP Holdings entered into a Simplification Agreement pursuant to which, upon closing, in exchange for the issuance by PAA to AAP of approximately 245.5 million common units representing limited partner interests in PAA and the assumption by PAA of AAP's outstanding debt (as of September 30, 2016, approximately $603 million but expected to be approximately $641 million as of November 15, 2016), AAP will contribute the IDRs to PAA and PAA GP's 2% economic general partner interest in PAA will be converted into a non-economic general partner interest in PAA. Following the closing of the Simplification Transactions, both PAA and PAGP will continue to be publicly traded. The Simplification Transactions are expected to close on November 15, 2016, subject to customary closing conditions. See Note 15 to our Condensed Consolidated Financial Statements for additional discussion of the Simplification Transactions.

Acquisitions and Capital Projects

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

	Nine Months Ended September 30,	
	2016	2015
Acquisition capital [(1)]	$289	$104
Expansion capital [(1)] [(2)]	1,065	1,837

Maintenance capital [2]	128	154
	$1,482	$2,095

(1) 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.

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(2) Capital expenditures made to expand the existing operating and/or earnings capacity of our assets are classified as expansion capital. Capital expenditures for the replacement 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 2016 and the forecasted expenditures for the year ending December 31, 2016 (in millions):

Projects	2016
Red River Pipeline (Cushing to Longview)	$310
Fort Saskatchewan Facility Projects	205
Permian Basin Area Pipeline Projects	185
Saddlehorn Pipeline	125
Diamond Pipeline	105
Cushing Terminal Expansions	70
St. James Terminal Expansions	50
Caddo Pipeline	35
Eagle Ford JV Project	25
Cactus Pipeline	20
Other Projects	295
	$1,425
Potential Adjustments for Timing / Scope Refinement (1)	-$50 +$50
Total Projected Expansion Capital Expenditures	$1,375 - $1,475
Maintenance Capital Expenditures	$175 - $185

(1) Potential variation to current capital costs estimates may result from (i) changes to project design, (ii) final cost of materials and labor and (iii) timing of incurrence of costs due to uncontrollable factors such as receipt of permits or regulatory approvals and weather.

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). See Note 13 to our Condensed Consolidated Financial Statements for additional information regarding our operating segments and segment performance measures.

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	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Transportation segment profit	$261	$254	$7	3 %	$760	$681	$79	12 %
Facilities segment profit	173	146	27	18 %	488	432	56	13 %
Supply and Logistics segment profit/(loss)	(6)	87	(93)	(107)%	13	258	(245)	(95)%
Total segment profit	428	487	(59)	(12)%	1,261	1,371	(110)	(8)%
Depreciation and amortization	(33)	(107)	74	69 %	(351)	(319)	(32)	(10)%
Interest expense, net	(113)	(109)	(4)	(4)%	(339)	(320)	(19)	(6)%
Other income/(expense), net	17	(4)	21	**	46	(7)	53	**
Income tax expense	(1)	(17)	16	94 %	(15)	(66)	51	77 %
Net income	298	250	48	19 %	602	659	(57)	(9)%
Net income attributable to noncontrolling interests	(1)	(1)	—	— %	(3)	(2)	(1)	(50)%
Net income attributable to PAA	$297	$249	$48	19 %	$599	$657	$(58)	(9)%
Basic net income per common unit	$0.40	$0.25	$0.15	60 %	$0.27	$0.54	$(0.27)	(50)%
Diluted net income per common unit	$0.40	$0.24	$0.16	67 %	$0.27	$0.53	$(0.26)	(49)%
Basic weighted average common units outstanding	401	398	3	1 %	399	393	6	2 %
Diluted weighted average common units outstanding	402	399	3	1 %	400	395	5	1 %

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

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 adjusted earnings before interest, taxes, depreciation and amortization (“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) 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), 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. Furthermore, the calculation of these measures contemplates tax effects as a separate reconciling item, where applicable. We have defined all such items as “Selected Items Impacting

Comparability."

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. These additional non-GAAP financial performance measures are reconciled to Net Income, the

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most directly comparable measure as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Condensed Consolidated Financial Statements and footnotes.

The following table sets forth non-GAAP financial measures that are reconciled to the most directly comparable GAAP measures (in millions):

	Three Months Ended September 30,		Favorable/(Unfavorable) Variance		Nine Months Ended September 30,		Favorable/(Unfavorable) Variance	
	2016	2015	$	%	2016	2015	$	%
Net income	$298	$250	$ 48	19 %	$602	$659	$ (57)	(9)%
Add:								
Interest expense, net	113	109	4	4 %	339	320	19	6 %
Income tax expense	1	17	(16)	(94)%	15	66	(51)	(77)%
Depreciation and amortization	33	107	(74)	(69)%	351	319	32	10 %
EBITDA	$445	$483	$ (38)	(8)%	$1,307	$1,364	$ (57)	(4)%
Selected Items Impacting Comparability of EBITDA:								
Gains/(losses) from derivative activities net of inventory valuation adjustments [1]	$69	$39	$ 30	77 %	$(147)	$(112)	$ (35)	(31)%
Long-term inventory costing adjustments [2]	(38)	(47)	9	19 %	6	(62)	68	110 %
Deficiencies under minimum volume commitments, net [3]	(25)	—	(25)	N/A	(59)	—	(59)	N/A
Equity-indexed compensation expense [4]	(8)	—	(8)	N/A	(23)	(22)	(1)	(5)%
Net gain/(loss) on foreign currency revaluation [5]	(3)	(6)	3	50 %	(1)	20	(21)	(105)%
Line 901 incident [6]	—	—	—	N/A	—	(65)	65	100 %
Selected Items Impacting Comparability of EBITDA	$(5)	$(14)	$ 9	64 %	$(224)	$(241)	$ 17	7 %

	Three Months Ended September 30,		Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Favorable/ (Unfavorable) Variance	
	2016	2015	$	%	2016	2015	$	%
EBITDA	$445	$483	$(38)	(8)%	$1,307	$1,364	$(57)	(4)%
Selected Items Impacting Comparability of EBITDA	5	14	(9)	(64)%	224	241	(17)	(7)%
Adjusted EBITDA	$450	$497	$(47)	(9)%	$1,531	$1,605	$(74)	(5)%
Interest expense, net [7]	(109)	(105)	(4)	(4)%	(327)	(309)	(18)	(6)%
Maintenance capital [8]	(47)	(52)	5	10 %	(128)	(154)	26	17 %
Current income tax expense	(4)	(11)	7	64 %	(45)	(72)	27	38 %
	4	12	(8)	(67)%	18	25	(7)	(28)%

Equity earnings in unconsolidated entities, net of distributions								
Distributions to noncontrolling interests [9]	(1)	(1)	—	— %	(3)	(3)	—	— %
Implied DCF [10]	$293	$340	$(47)	(14)%	$1,046	$1,092	$(46)	(4)%
Less: Cash Distributions [9]	(328)	(433)			(1,194)	(1,281)		
DCF Excess/(Shortage) [11]	$(35)	$(93)			$(148)	$(189)		

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(1) 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 9 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities and our Preferred Distribution Rate Reset Option.

(2) We carry approximately 5 million barrels of 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 2015 Annual Report on Form 10-K for a complete discussion of our long-term inventory.

(3) 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.

(4) 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 15 to our Consolidated Financial Statements included in Part IV of our 2015 Annual Report on Form 10-K for a comprehensive discussion regarding our equity-indexed compensation plans.

(5) 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.

(6) 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 regarding the Line 901 incident.

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

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

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

(10) Including costs of $65 million related to the Line 901 incident that were recognized during the nine months ended September 30, 2015, Implied DCF would have been $1.027 billion for the nine months ended September 30, 2015. See Note 12 to our Condensed Consolidated Financial Statements for additional information regarding the Line 901 incident.

(11) 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 Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 18 to our Consolidated Financial Statements included in Part IV of our 2015 Annual Report on Form 10-K for further discussion of how we evaluate segment profit. See Note 13 to our Condensed Consolidated Financial Statements for a reconciliation of segment profit 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:

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Operating Results [1]	Three Months Ended September 30,		Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Favorable/ (Unfavorable) Variance	
(in millions, except per barrel data)	2016	2015	$	%	2016	2015	$	%
Revenues								
Tariff activities	$364	$364	$ —	— %	$1,079	$1,083	$ (4)	— %
Trucking	37	37	—	— %	109	120	(11)	(9)%
Total transportation revenues	401	401	—	— %	1,188	1,203	(15)	(1)%
Costs and expenses								
Trucking costs	(24)	(26)	2	8 %	(69)	(85)	16	19 %
Field operating costs [2]	(133)	(147)	14	10 %	(406)	(493)	87	18 %
Equity-indexed compensation (expense)/benefit - operations	(3)	1	(4)	(400)%	(9)	(5)	(4)	(80)%
Segment general and administrative expenses [2] [3]	(22)	(23)	1	4 %	(67)	(67)	—	— %
Equity-indexed compensation (expense)/benefit - general and administrative	(4)	3	(7)	(233)%	(10)	(6)	(4)	(67)%
Equity earnings in unconsolidated entities	46	45	1	2 %	133	134	(1)	(1)%
Segment profit	$261	$254	$ 7	3 %	$760	$681	$ 79	12 %
Maintenance capital	$29	$34	$ 5	15 %	$86	$101	$ 15	15 %
Segment profit per barrel	$0.62	$0.61	$ 0.01	2 %	$0.60	$0.56	$ 0.04	7 %

Average Daily Volumes	Three Months Ended September 30,		Favorable/(Unfavorable) Variance		Nine Months Ended September 30,		Favorable/(Unfavorable)Var	
(in thousands of barrels per day) [4]	2016	2015	Volumes	%	2016	2015	Volumes	%
Tariff activities volumes								
Crude oil pipelines (by region):								
Permian Basin [5]	2,162	1,885	277	15 %	2,129	1,810	319	18 %
South Texas / Eagle Ford [5]	263	321	(58)	(18)%	283	298	(15)	(5)%
Western	194	196	(2)	(1)%	193	223	(30)	(13)%
Rocky Mountain [5]	475	447	28	6 %	448	442	6	1 %
Gulf Coast	423	576	(153)	(27)%	538	531	7	1 %
Central [5]	403	424	(21)	(5)%	393	430	(37)	(9)%
Canada	379	384	(5)	(1)%	384	397	(13)	(3)%
Crude oil pipelines	4,299	4,233	66	2 %	4,368	4,131	237	6 %
NGL pipelines	185	200	(15)	(8)%	182	195	(13)	(7)%
Tariff activities total volumes	4,484	4,433	51	1 %	4,550	4,326	224	5 %
Trucking	118	112	6	5 %	113	114	(1)	(1)%
Transportation segment total volumes	4,602	4,545	57	1 %	4,663	4,440	223	5 %

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

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

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends 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. Revenue from our pipeline capacity agreements generally reflects a negotiated amount.

The following is a discussion of items impacting Transportation segment profit and segment profit per barrel for the periods indicated.

Tariff Activities Revenues, Equity Earnings in Unconsolidated Entities and Volumes. As noted in the table above, revenues from tariff activities and equity earnings in unconsolidated entities were relatively consistent for the three and nine months ended September 30, 2016 compared to the same 2015 periods, while volumes increased for both comparative periods presented. The revenues, equity earnings and volumes reported for the periods do not include net deferred revenues of $30 million and $54 million for the three and nine months ended September 30, 2016, respectively, related to agreements that require counterparties to deliver or transport a minimum volume during the period. The net amounts deferred are for volume commitments for which the counterparty did not fulfill its volume commitment, but which have been billed and collected from the counterparty.

The following table presents significant tariff activities revenues and equity earnings in unconsolidated entities variances by region for the comparative periods presented:

	Favorable/(Unfavorable) Variance Three Months Ended September 30, 2016-2015		Favorable/(Unfavorable) Variance Nine Months Ended September 30, 2016-2015	
(in millions)	Revenues	Equity Earnings	Revenues	Equity Earnings
Tariff activities:				
Permian Basin region	$ 20	$ 2	$ 78	$ —
Rocky Mountain region	(7)	2	(10)	5
Gulf Coast region	(9)	—	(8)	—
Central region	(7)	—	(18)	1
Other (including pipeline loss allowance revenue)	3	(3)	(46)	(7)
Total variance	$ —	$ 1	$ (4)	$ (1)

- Permian Basin region — The increase in revenues for the comparative 2016 periods presented was largely driven by higher volumes associated with the expansion of our pipeline systems in the Delaware Basin, as well as higher volumes on our takeaway pipelines. For the nine month comparative period, the increase in revenues was also driven by results from our Cactus pipeline, which was placed in service in April 2015 and was in a ramp-up phase for the following months, and which also favorably impacted volumes on our McCamey pipeline system which connects our

Midland terminal to the Cactus pipeline origin station.

- Rocky Mountain region — The decrease in revenues for the three and nine months ended September 30, 2016 versus the comparable 2015 periods was largely driven by (i) decreased tariffs on certain of our Bakken area pipelines, (ii) crude oil quality issues that resulted in lower movements on our Robinson Lake pipeline for the 2016 periods, (iii) lower volumes due to production declines and increased competition and (iv) 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.

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Equity earnings increased for the three and nine month comparative periods 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. The nine-month comparative period was further favorably impacted by contributions from our investment in Frontier, in which we purchased an additional interest in August 2015.

- Gulf Coast region — Revenues and volumes decreased for the three and nine months ended September 30, 2016 compared to the same 2015 periods primarily due to the sale of certain of our Gulf Coast pipelines in March 2016 and July 2016. These decreases were partially offset by increased volumes on the Capline and Pascagoula pipelines, which were favorably impacted by higher refinery demand, but were at lower tariff rates than the pipelines that were sold.

- Central region — The decrease in revenues for the three and nine months ended September 30, 2016 versus the comparable 2015 periods was largely driven by lower volumes due to production declines in the Mid-Continent area.

- Other — The decrease in other revenues for the nine months ended September 30, 2016 was primarily related to lower pipeline loss allowance revenue of $36 million driven by a lower average realized price per barrel.

The decrease in equity earnings for the nine months ended September 30, 2016 was primarily due to less favorable results from our investment in Settoon, which was impacted by lower demand for barge and towing movements.

Trucking Revenues. The decrease in trucking revenues for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015 was primarily driven by unfavorable foreign exchange impacts of $6 million.

Trucking Costs. Trucking costs decreased for the nine months ended September 30, 2016 compared to the same 2015 period due to lower contract services rates, as well as favorable foreign exchange impacts of $4 million.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015 primarily due to net costs of approximately $65 million associated with the Line 901 incident that were recognized in the second quarter of 2015. See Note 12 to our Condensed Consolidated Financial Statements for additional information regarding the Line 901 incident. The decrease in both the three and nine months ended September 30, 2016 as compared to the three and nine months ended September 30, 2015 was further driven by lower utilities and maintenance costs, costs associated with the MP29 release in the third quarter of 2015 and lower operating costs due to the sale of certain of our Gulf Coast pipelines in March 2016 and July 2016. The decrease for the nine-month comparative period was also due to a favorable foreign exchange impact of $5 million, partially offset by an increase in integrity management costs.

Equity-Indexed Compensation Expense. On a consolidated basis, equity-indexed compensation expense increased by $22 million for the three months ended September 30, 2016 compared to the same period in 2015, primarily due to the impact of the increase in unit price during the three months ended September 30, 2016 compared to the impact of the decrease in unit price during the same period in 2015, partially offset by the impact of lower average values per LTIP unit during the 2016 period compared to the same period in 2015.

On a consolidated basis across all segments, equity-indexed compensation expense increased by $13 million for the nine months ended September 30, 2016 compared to the same period in 2015, primarily due to the impact of the increase in unit price during the nine months ended September 30, 2016 compared to the impact of the decrease in unit price during the same period in 2015, partially offset by the impact of fewer probable LTIP units outstanding and lower average values per LTIP unit during the 2016 period compared to the same period in 2015.

Allocations of equity-indexed compensation expense vary over time between field operating costs and general and administrative expenses, as well as between segments, and could result in variances in those expense categories or segments that differ from the consolidated variance explanations above. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2015 Annual Report on Form 10-K for additional information regarding our equity-indexed compensation plans.

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 decrease in

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maintenance capital for the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015 was primarily driven by lower third party service costs and timing of projects.

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 September 30,		Favorable/(Unfavorable) Variance		Nine Months Ended September 30,		Favorable/(Unfavorable) Variance	
(in millions, except per barrel data)	2016	2015	$	%	2016	2015	$	%
Revenues	$282	$263	$ 19	7 %	$817	$789	$ 28	4 %
Natural gas related storage costs	(6)	(7)	1	14 %	(17)	(17)	—	— %
Field operating costs [2]	(85)	(96)	11	11 %	(258)	(284)	26	9 %
Equity-indexed compensation (expense)/benefit - operations	(1)	1	(2)	(200)%	(3)	(1)	(2)	(200)%
Segment general and administrative expenses [2] [3]	(15)	(17)	2	12 %	(44)	(50)	6	12 %
Equity-indexed compensation (expense)/benefit - general and administrative	(2)	2	(4)	(200)%	(7)	(5)	(2)	(40)%
Segment profit	$173	$146	$ 27	18 %	$488	$432	$ 56	13 %
Maintenance capital	$15	$16	$ 1	6 %	$32	$48	$ 16	33 %
Segment profit per barrel	$0.44	$0.39	$ 0.05	13 %	$0.42	$0.38	$ 0.04	11 %

Volumes [4]	Three Months Ended September 30,		Favorable/(Unfavorable) Variance		Nine Months Ended September 30,		Favorable/(Unfavorable) Variance	
	2016	2015	Volumes	%	2016	2015	Volumes	%
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	109	100	9	9 %	106	99	7	7 %
Rail load / unload volumes (average volumes in thousands of barrels per day)	73	231	(158)	(68)%	97	223	(126)	(57)%
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	98	21	21 %	113	101	12	12 %
Facilities segment total (average monthly volumes in millions of barrels) [5]	131	126	5	4 %	129	126	3	2 %

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

(5) Facilities segment total 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 profit and segment profit per barrel for the periods indicated.

Revenues and Volumes. As noted in the table above, our Facilities segment revenues increased by $19 million and $28 million for the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015, respectively. Total volumes increased for both comparative periods presented. Our Facilities segment results for the comparative periods were impacted by:

- Crude Oil Storage — Revenues increased by $5 million and $23 million for the three and nine months ended September 30, 2016, respectively, as compared to the three and nine months ended September 30, 2015 primarily due to (i) increased utilization at certain of our West Coast terminals and (ii) aggregate capacity expansions of approximately 5 million barrels at our St. James and Cushing terminals. Such increases were partially offset by lower results due to the sale of certain of our East Coast terminals in April 2016.

- Rail Terminals — Revenues decreased by $1 million and $16 million for the three and nine month comparative periods, respectively, primarily due to lower volumes at our U.S. terminals as a result of production declines in the Bakken and less favorable market conditions, partially offset by revenue associated with minimum volume commitments entered into during 2016 at certain of our terminals, and revenues and volumes from our Canadian NGL rail terminal that came online in April 2016. The three-month comparative period was further favorably impacted by the recognition of revenue associated with minimum volume commitments that had been deferred in prior quarters of 2016.

- NGL Storage, NGL Fractionation and Canadian Natural Gas Processing — Revenues increased by $18 million and $25 million for the three and nine months ended September 30, 2016, respectively, compared to the same periods in 2015 primarily due to (i) contributions from the Western Canada NGL assets we acquired in August 2016 and (ii) higher fees at certain of our NGL storage and fractionation facilities. For the nine-month comparative period, such increases were partially offset by unfavorable foreign exchange impacts of approximately $10 million.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015 primarily due to lower costs related to contract services, primarily at our rail terminals and, to a lesser extent, at our processing facilities, as well as the impact of the sale of certain of our East Coast terminals in April 2016. The nine-month comparative period was also impacted by lower utilities costs and a favorable foreign exchange impact of $5 million. These decreases were partially offset by an increase in operating costs due to the Western Canada NGL assets acquired in August 2016.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expense) decreased for the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015 primarily due to cost reduction efforts and lower costs incurred for legal fees.

Maintenance Capital. The decrease in maintenance capital for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015 was primarily due to lower spending on various tank and other maintenance capital projects, partially due to the timing of certain 2015 projects at our NGL storage and fractionation facilities.

Supply and Logistics Segment

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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 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 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 and relative fluctuations in market-related indices.

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

Operating Results [1]	Three Months Ended September 30,		Favorable/(Unfavorable) Variance		Nine Months Ended September 30,		Favorable/(Unfavorable) Variance	
(in millions, except per barrel data)	2016	2015	$	%	2016	2015	$	%
Revenues	$4,879	$5,254	$ (375)	(7)%	$13,353	$17,238	$(3,885)	(23)%
Purchases and related costs [2]	(4,788)	(5,032)	244	5 %	(13,031)	(16,553)	3,522	21 %
Field operating costs [3]	(70)	(110)	40	36 %	(226)	(338)	112	33 %
Equity-indexed compensation expense - operations	—	—	—	N/A	(1)	—	(1)	N/A
Segment general and administrative expenses [3] [4]	(23)	(26)	3	12 %	(72)	(79)	7	9 %
Equity-indexed compensation (expense)/benefit - general and administrative	(4)	1	(5)	(500)%	(10)	(10)	—	— %
Segment profit/(loss)	$(6)	$87	$ (93)	(107)%	$13	$258	$(245)	(95)%
Maintenance capital	$3	$2	$ (1)	(50)%	$10	$5	$(5)	(100)%
Segment profit/(loss) per barrel	$(0.06)	$0.84	$ (0.90)	(107)%	$0.04	$0.81	$(0.77)	(95)%

Average Daily Volumes	Three Months Ended September 30,		Favorable/(Unfavorable) Variance		Nine Months Ended September 30,		Favorable/(Unfavorable) Variance	
(in thousands of barrels per day)	2016	2015	Volumes	%	2016	2015	Volumes	%
Crude oil lease gathering purchases	883	927	(44)	(5)%	894	958	(64)	(7)%
NGL sales	207	183	24	13 %	230	209	21	10 %
Waterborne cargos	8	4	4	100 %	7	1	6	600 %
Supply and Logistics segment total	1,098	1,114	(16)	(1)%	1,131	1,168	(37)	(3)%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of $5 million and $1 million for the three months ended September 30, 2016 and 2015, respectively, and $10 million and $4 million for the nine months ended September 30, 2016 and 2015, respectively.

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

(4) 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.

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

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	NYMEX WTI Crude Oil Price	
	Low	High
Three months ended September 30, 2016	$ 40	$ 49
Three months ended September 30, 2015	$ 38	$ 57
Nine months ended September 30, 2016	$ 26	$ 51
Nine months ended September 30, 2015	$ 38	