PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
August 08, 2016
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 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. x 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). x 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 x	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 x No

As of August 1, 2016, there were 397,736,728 Common Units outstanding.

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

TABLE OF CONTENTS

	Page
PART I. FINANCIAL INFORMATION	
Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS:	
Condensed Consolidated Balance Sheets: As of June 30, 2016 and December 31, 2015	3
Condensed Consolidated Statements of Operations: For the three and six months ended June 30, 2016 and 2015	4
Condensed Consolidated Statements of Comprehensive Income: For the three and six months ended June 30, 2016 and 2015	5
Condensed Consolidated Statements of Changes in Accumulated Other Comprehensive Income/(Loss): For the six months ended June 30, 2016 and 2015	5
Condensed Consolidated Statements of Cash Flows: For the six months ended June 30, 2016 and 2015	6
Condensed Consolidated Statements of Changes in Partners Capital: For the six months ended June 30, 2016 and 2015	7
Notes to the Condensed Consolidated Financial Statements:	
1. Organization and Basis of Consolidation and Presentation	8
2. Recent Accounting Pronouncements	9
3. Net Income Per Common Unit	9
4. Accounts Receivable, Net	11
5. Inventory, Linefill and Base Gas and Long-term Inventory	11
6. Goodwill	12
7. Debt	12
8. Partners Capital and Distributions	13
9. Derivatives and Risk Management Activities	14
10. Related Party Transactions	22
11. Commitments and Contingencies	22
12. Operating Segments	27
13. Acquisitions, Dispositions and Impairments	28
14. Simplification Transactions	28
Item 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	31
Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	51
Item 4. CONTROLS AND PROCEDURES	53
PART II. OTHER INFORMATION	
Item 1. LEGAL PROCEEDINGS	54
Item 1A. RISK FACTORS	54
Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS	54
Item 3. DEFAULTS UPON SENIOR SECURITIES	54
Item 4. MINE SAFETY DISCLOSURES	54
Item 5. OTHER INFORMATION	54
Item 6. EXHIBITS	54
SIGNATURES	55

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except unit data)

	June 30, 2016	December 31, 2015
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 34	$ 27
Trade accounts receivable and other receivables, net	2,015	1,785
Inventory	1,085	916
Other current assets	469	241
Total current assets	3,603	2,969
PROPERTY AND EQUIPMENT	15,849	15,654
Accumulated depreciation	(2,251)	(2,180)
Property and equipment, net	13,598	13,474
OTHER ASSETS		
Goodwill	2,396	2,405
Investments in unconsolidated entities	2,161	2,027
Linefill and base gas	902	898
Long-term inventory	184	129
Other long-term assets, net	319	386
Total assets	$ 23,163	$ 22,288
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,332	$ 2,038
Short-term debt	1,302	999
Other current liabilities	395	370
Total current liabilities	4,029	3,407
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discounts and debt issuance costs	9,128	9,698
Other long-term debt	358	677
Other long-term liabilities and deferred credits	678	567
Total long-term liabilities	10,164	10,942
COMMITMENTS AND CONTINGENCIES (NOTE 11)		

PARTNERS CAPITAL				
Series A preferred unitholders (61,888,566 units outstanding)		1,509		
Common unitholders (397,736,728 and 397,727,624 units outstanding, respectively)		7,085		7,580
General partner		318		301
Total partners capital excluding noncontrolling interests		8,912		7,881
Noncontrolling interests		58		58
Total partners capital		8,970		7,939
Total liabilities and partners capital	$	23,163	$	22,288

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$ 4,648	$ 6,346	$ 8,467	$ 11,978
Transportation segment revenues	170	180	323	366
Facilities segment revenues	132	137	270	261
Total revenues	4,950	6,663	9,060	12,605
COSTS AND EXPENSES				
Purchases and related costs	4,224	5,848	7,571	10,890
Field operating costs	303	417	603	763
General and administrative expenses	73	79	140	157
Depreciation and amortization	204	108	319	212
Total costs and expenses	4,804	6,452	8,633	12,022
OPERATING INCOME	146	211	427	583
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	40	52	87	89
Interest expense (net of capitalized interest of $12, $13, $26 and $27, respectively)	(114)	(107)	(227)	(212)
Other income/(expense), net	25	1	30	(3)
INCOME BEFORE TAX	97	157	317	457
Current income tax expense	(9)	(19)	(40)	(61)
Deferred income tax benefit/(expense)	14	(14)	27	12
NET INCOME	102	124	304	408
Net income attributable to noncontrolling interests	(1)		(2)	(1)
NET INCOME ATTRIBUTABLE TO PAA	$ 101	$ 124	$ 302	$ 407
BASIC NET INCOME/(LOSS) PER COMMON UNIT (NOTE 3):				
Net income/(loss) allocated to common unitholders Basic	$ (81)	$ (23)	$ (53)	$ 113
Basic weighted average common units outstanding	398	397	398	390
Basic net income/(loss) per common unit	$ (0.20)	$ (0.06)	$ (0.13)	$ 0.29
Net income/(loss) allocated to common unitholders Diluted	$ (81)	$ (23)	$ (53)	$ 113
Diluted weighted average common units outstanding	398	397	398	393
Diluted net income/(loss) per common unit	$ (0.20)	$ (0.06)	$ (0.13)	$ 0.29

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
Net income	$ 102	$ 124	$ 304	$ 408
Other comprehensive income/(loss)	(73)	170	45	(206)
Comprehensive income	29	294	349	202
Comprehensive income attributable to noncontrolling interests	(1)		(2)	(1)
Comprehensive income attributable to PAA	$ 28	$ 294	$ 347	$ 201

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	6		6
Deferred loss on cash flow hedges	(158)		(158)
Currency translation adjustments		197	197
Total period activity	(152)	197	45
Balance at June 30, 2016	$ (355)	$ (681)	$ (1,036)

	Derivative Instruments	Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2014	$ (159)	$ (308)	$ (467)
Reclassification adjustments	19		19
Deferred gain on cash flow hedges	20		20
Currency translation adjustments		(245)	(245)

Total period activity		39		(245)		(206)
Balance at June 30, 2015	$	(120)	$	(553)	$	(673)

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Six Months Ended June 30, (unaudited)	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 304	$ 408
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	319	212
Equity-indexed compensation expense	26	36
Inventory valuation adjustments	3	24
Deferred income tax benefit	(27)	(12)
Gain on foreign currency revaluation	(2)	(26)
Settlement of terminated interest rate hedging instruments	(50)	(29)
Change in fair value of Preferred Distribution Rate Reset Option (Note 9)	(25)	
Equity earnings in unconsolidated entities	(87)	(89)
Distributions from unconsolidated entities	101	102
Other	6	(6)
Changes in assets and liabilities, net of acquisitions	(181)	40
Net cash provided by operating activities	387	660
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions	(85)	(64)
Investments in unconsolidated entities	(120)	(119)
Additions to property, equipment and other	(699)	(1,031)
Cash paid for purchases of linefill and base gas	(7)	(125)
Proceeds from sales of assets	391	2
Other investing activities	(2)	(6)
Net cash used in investing activities	(522)	(1,343)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) under commercial paper program (Note 7)	(844)	151
Net borrowings under senior secured hedged inventory facility (Note 7)	252	
Repayments of senior notes		(149)
Net proceeds from the sale of Series A preferred units (Note 8)	1,569	
Net proceeds from the sale of common units		1,099
Contributions from general partner	33	23
Distributions paid to common unitholders (Note 8)	(557)	(526)
Distributions paid to general partner (Note 8)	(309)	(284)
Other financing activities	(6)	(5)
Net cash provided by financing activities	138	309
Effect of translation adjustment on cash	4	(1)
Net increase/(decrease) in cash and cash equivalents	7	(375)
Cash and cash equivalents, beginning of period	27	403
Cash and cash equivalents, end of period	$ 34	$ 28
Cash paid for:		

Interest, net of amounts capitalized	$	225	$	190
Income taxes, net of amounts refunded	$	51	$	30

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

Table of Contents

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		11	291	302	2	304
Cash distributions to partners		(557)	(309)	(866)	(2)	(868)
Sale of Series A preferred units	1,509		33	1,542		1,542
Other comprehensive income		44	1	45		45
Other		7	1	8		8
Balance at June 30, 2016	$ 1,509	$ 7,085	$ 318	$ 8,912	$ 58	$ 8,970

	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	116	291	407	1	408
Cash distributions to partners	(526)	(284)	(810)	(1)	(811)
Sale of common units	1,099	22	1,121		1,121
Other comprehensive loss	(202)	(4)	(206)		(206)
Other		2	2		2
Balance at June 30, 2015	$ 8,280	$ 367	$ 8,647	$ 58	$ 8,705

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

Table of Contents

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 12 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 June 30, 2016, owned an approximate 43% 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, both PAA and PAGP will continue to be publicly traded. See Note 14 for further discussion of this transaction.

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

Table of Contents

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 $5 million reclassified from Depreciation and amortization to Interest expense, net in our accompanying Condensed Consolidated Statements of Operations for the three and six months ended June 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 six months ended June 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 six months ended June 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, and we are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations and cash flows.

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 we are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations and 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.

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.

Table of Contents

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 six months ended June 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 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. LTIP awards were excluded from the computation of diluted net loss per common unit for the three months ended June 30, 2016 and 2015 and the six months ended June 30, 2016 as the effect was antidilutive. 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Basic Net Income per Common Unit				
Net income attributable to PAA	$ 101	$ 124	$ 302	$ 407
Distributions to Series A preferred units(1)	(33)		(55)	
Distributions to general partner (1)	(155)	(152)	(310)	(300)
Distributions to participating securities (1)	(1)	(1)	(2)	(3)
Undistributed loss allocated to general partner (1)	7	6	12	9
Net income/(loss) allocated to common unitholders in accordance with application of the two-class method for MLPs	$ (81)	$ (23)	$ (53)	$ 113
Basic weighted average common units outstanding	398	397	398	390
Basic net income/(loss) per common unit	$ (0.20)	$ (0.06)	$ (0.13)	$ 0.29
Diluted Net Income per Common Unit				
Net income attributable to PAA	$ 101	$ 124	$ 302	$ 407
Distributions to Series A preferred units(1)	(33)		(55)	
Distributions to general partner (1)	(155)	(152)	(310)	(300)
Distributions to participating securities (1)	(1)	(1)	(2)	(3)
Undistributed loss allocated to general partner (1)	7	6	12	9
Net income/(loss) allocated to common unitholders in accordance with application of the two-class method for MLPs	$ (81)	$ (23)	$ (53)	$ 113
Basic weighted average common units outstanding	398	397	398	390
Effect of dilutive securities: Weighted average LTIP units				3
Diluted weighted average common units outstanding	398	397	398	393
Diluted net income/(loss) per common unit	$ (0.20)	$ (0.06)	$ (0.13)	$ 0.29

(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.

Table of Contents

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.

Note 4 Accounts Receivable, Net

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL and natural gas. To mitigate credit risk related to our accounts receivable, we utilize a rigorous credit review process. We closely monitor market conditions to make a determination with respect to the amount, if any, of open credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of advance cash payments, standby letters of credit or parental guarantees. As of June 30, 2016 and December 31, 2015, we had received $93 million and $88 million, respectively, of advance cash payments from third parties to mitigate credit risk.

We also received $73 million and $36 million as of June 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 June 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 $4 million at both June 30, 2016 and December 31, 2015. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

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

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

	June 30, 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	20,013	barrels	$ 819	$ 40.92	16,345	barrels	$ 608	$ 37.20
NGL	12,813	barrels	209	$ 16.31	13,907	barrels	218	$ 15.68

Natural gas	15,055	Mcf	31	$	2.06	22,080	Mcf	53	$	2.40
Other	N/A		26		N/A	N/A		37		N/A
Inventory subtotal			1,085					916		
Linefill and base gas										
Crude oil	12,227	barrels	716	$	58.56	12,298	barrels	713	$	57.98
NGL	1,355	barrels	45	$	33.21	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			902					898		
Long-term inventory										
Crude oil	3,396	barrels	162	$	47.70	3,417	barrels	106	$	31.02
NGL	1,418	barrels	22	$	15.51	1,652	barrels	23	$	13.92
Long-term inventory subtotal			184					129		
Total			$ 2,171					$ 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.

Table of Contents

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	14	6	2	22
Dispositions	(15)	(16)		(31)
Balance at June 30, 2016	$ 814	$ 1,077	$ 505	$ 2,396

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):

	June 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)	$ 172	$ 696
Senior secured hedged inventory facility, bearing a weighted-average interest rate of 1.4% and 1.4%, respectively (1)	552	300
Senior notes:		
5.88% senior notes due August 2016	175	
6.13% senior notes due January 2017	400	
Other	3	3
Total short-term debt	1,302	999
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $72 and $77, respectively	9,128	9,698
Commercial paper notes, bearing a weighted-average interest rate of 1.3% and 1.1%, respectively	354	672
Other	4	5
Total long-term debt	9,486	10,375
Total debt (2)	$ 10,788	$ 11,374

(1) We classified these commercial paper notes and credit facility borrowings as short-term as of June 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) Our fixed-rate senior notes (including current maturities) had a face value of approximately $9.8 billion as of both June 30, 2016 and December 31, 2015. We estimated the aggregate fair value of these notes as of June 30, 2016 and December 31, 2015 to be approximately $9.6 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.

Table of Contents

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the six months ended June 30, 2016 and 2015 were approximately $23.0 billion and $17.9 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $23.6 billion and $17.7 billion for the six months ended June 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 June 30, 2016 and December 31, 2015, we had outstanding letters of credit of $48 million and $46 million, respectively.

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 distribution	858,439	
Issuance of common units under LTIP		9,104
Outstanding at June 30, 2016	61,888,566	397,736,728

	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	438,517
Outstanding at June 30, 2015	397,680,214

Equity Offerings

Series A Preferred Unit Offering. In January 2016, 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 will receive 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. Our general partner will be entitled to participate in cash distributions on the Series A preferred units equal to its 2% general partner interest.

The purchasers may convert their Series A preferred 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 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.

Table of Contents

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.

Distributions

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

		Distributions			Distributions per
Date Declared	**Distribution Date**	**Common Unitholders**	**General Partner**	**Total**	**common unit**
July 11, 2016	August 12, 2016 (1)	$ 278	$ 155	$ 433	$ 0.70
April 7, 2016	May 13, 2016	$ 278	$ 155	$ 433	$ 0.70
January 12, 2016	February 12, 2016	$ 278	$ 155	$ 433	$ 0.70

(1) Payable to unitholders of record at the close of business on July 29, 2016 for the period April 1, 2016 through June 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 will issue 1,237,765 additional Series A preferred units in lieu of a cash distribution of $33 million. Since the August 12, 2016 Series A preferred unit distribution was declared as payment-in-kind, this distribution payable was accrued to partners capital as of June 30, 2016 and thus had no net impact on the Series A preferred unitholders capital account.

Noncontrolling Interests in Subsidiaries

As of June 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:

Table of Contents

Commodity Purchases and Sales In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of June 30, 2016, net derivative positions related to these activities included:

- A net long position of 2.1 million barrels associated with our crude oil purchases, which was unwound ratably during July 2016 to match monthly average pricing.

- A net short time spread position of 3.9 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through August 2017.

- A crude oil grade spread position of 7.0 million barrels through December 2018. These derivatives allow us to lock in grade basis differentials.

- A net short position of 13.0 Bcf through July 2017 related to anticipated sales of natural gas inventory.

- A net short position of 25.8 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 June 30, 2016, our PLA hedges included a long call option position of 1.2 million barrels through December 2018.

Natural Gas Processing/NGL Fractionation We purchase natural gas for processing and operational needs. Additionally, we purchase NGL mix for fractionation and sell the resulting individual specification products (including ethane, propane, butane and condensate). In conjunction with these activities, we hedge the price risk associated with the purchase of the natural gas and the subsequent sale of the individual specification products. As of June 30, 2016, we had a long natural gas position of 22.0 Bcf through December 2017, a short propane position of 4.2 million barrels through December 2017, a short butane position of 1.3 million barrels through December 2017 and a short WTI position of 0.5 million barrels through December 2017. In addition, we had a long power position of 0.3 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 June 30, 2016, AOCI includes deferred losses of $334 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.

Table of Contents

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 June 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 June 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 June 30, 2016 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2016	$ 19	$ 25	$1.00 - $1.29
Forward exchange contracts that exchange USD for CAD:				
	2016	$ 186	$ 241	$1.00 - $1.29
	2017	$ 20	$ 26	$1.00 - $1.29

Preferred Distribution Rate Reset Option

A derivative feature embedded in a contract that does not meet the definition of a derivative in its entirety must be bifurcated and accounted for separately if the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract. The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value on our Condensed Consolidated Balance Sheets. Corresponding changes in fair value are recognized in Other income/(expense), net in our Condensed Consolidated Statement of Operations. At June 30, 2016, the fair value of this embedded derivative was a liability of approximately $35 million. We recognized a gain of approximately $25 million during the three and six months ended June 30, 2016 due to changes in fair value during the period. See Note 8 for additional information regarding our Series A preferred units and the Preferred Distribution Rate Reset Option.

Summary of Financial Impact

We record all open derivatives on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify as cash flow hedges, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions are recognized in earnings. Derivatives that do not qualify for hedge

Table of Contents

accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items are recognized in earnings each period. Cash settlements associated with our derivative activities are classified within the same category as the related hedged item in our Condensed Consolidated Statements of Cash Flows.

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

	Three Months Ended June 30, 2016			Three Months Ended June 30, 2015		
Location of Gain/(Loss)	**Derivatives in Hedging Relationships (1)**	**Derivatives Not Designated as a Hedge**	**Total**	**Derivatives in Hedging Relationships**	**Derivatives Not Designated as a Hedge**	**Total**
Commodity Derivatives						
Supply and Logistics segment revenues	$ (1)	$ (159)	$ (160)	$ (19)	$ 44	$ 25
Transportation segment revenues		1	1		2	2
Field operating costs		2	2		2	2
Interest Rate Derivatives						
Interest expense, net	(4)		(4)	(4)		(4)
Foreign Currency Derivatives						
Supply and Logistics segment revenues		(1)	(1)			
Preferred Distribution Rate Reset Option						
Other income/(expense), net		25	25			
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (5)	$ (132)	$ (137)	$ (23)	$ 48	$ 25

	Six Months Ended June 30, 2016			Six Months Ended June 30, 2015		
Location of Gain/(Loss)	**Derivatives in Hedging Relationships (1)**	**Derivatives Not Designated as a Hedge**	**Total**	**Derivatives in Hedging Relationships**	**Derivatives Not Designated as a Hedge**	**Total**
Commodity Derivatives						
Supply and Logistics segment revenues	$	$ (128)	$ (128)	$ (12)	$ 10	$ (2)
Transportation segment revenues		3	3		4	4

Field operating costs							(2)	(2)
Interest Rate Derivatives								
Interest expense, net	(6)		(6)		(5)			(5)
Foreign Currency Derivatives								
Supply and Logistics segment revenues		5	5			(17)		(17)
Preferred Distribution Rate Reset Option								
Other income/(expense), net		25	25					
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (6)	$ (95)	$ (101)	$ (17)		$ (5)		$ (22)

Table of Contents

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

The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of June 30, 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	$ 2		
Interest rate derivatives			Other current liabilities	$ (64)
			Other long-term liabilities and deferred credits	(91)
Total derivatives designated as hedging instruments		$ 2		$ (155)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 45	Other current assets	$ (182)
	Other long-term liabilities and deferred credits	6	Other current liabilities	(6)
			Other long-term liabilities and deferred credits	(17)
Foreign currency derivatives			Other current liabilities	(1)
Preferred Distribution Rate Reset Option			Other long-term liabilities and deferred credits	(35)
Total derivatives not designated as hedging instruments		$ 51		$ (241)
Total derivatives		$ 53		$ (396)

Table of Contents

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		Liability Derivatives	
	Balance Sheet Location	Fair Value	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 June 30, 2016, we had a net broker receivable of $274 million (consisting of initial margin of $84 million increased by $190 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).

19

Table of Contents

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

	June 30, 2016		December 31, 2015	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 53	$ (396)	$ 280	$ (110)
Netting adjustment	(188)	188	(38)	38
Cash collateral paid/(received)	274		(156)	
Net position - asset/(liability)	$ 139	$ (208)	$ 86	$ (72)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 139	$	$ 76	$
Other long-term assets, net			10	
Other current liabilities		(71)		(38)
Other long-term liabilities and deferred credits		(137)		(34)
	$ 139	$ (208)	$ 86	$ (72)

As of June 30, 2016, there was a net loss of $355 million deferred in AOCI. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transaction or (ii) interest expense accruals associated with underlying debt instruments. Of the total net loss deferred in AOCI at June 30, 2016, we expect to reclassify a net loss of $5 million to earnings in the next twelve months. The remaining deferred loss of $350 million is expected to be reclassified to earnings through 2049. A portion of these amounts is based on market prices as of June 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Commodity derivatives, net	$	$ (28)	$	$ (25)
Interest rate derivatives, net	(68)	120	(158)	45
Total	$ (68)	$ 92	$ (158)	$ 20

At June 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 June 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	$ (133)	$ (19)	$	$ (152)	$ 126	$ 90	$ 11	$ 227
Interest rate derivatives		(155)		(155)		(49)		(49)
Foreign currency derivatives		(1)		(1)		(8)		(8)
Preferred Distribution Rate Reset Option			(35)	(35)				
Total net derivative asset/(liability)	$ (133)	$ (175)	$ (35)	$ (343)	$ 126	$ 33	$ 11	$ 170

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

Table of Contents

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

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

Rollforward of Level 3 Net Asset/(Liability)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Beginning Balance	$ (59)	$ 5	$ 11	$ 15
Gains for the period included in earnings	23	1	23	1
Settlements		(1)	(9)	(13)
Derivatives entered into during the period	1	4	(60)	6
Ending Balance	$ (35)	$ 9	$ (35)	$ 9
Change in unrealized gains included in earnings relating to Level 3 derivatives still held at the end of the period	$ 24	$ 5	$ 24	$ 6

Table of Contents

Note 10 Related Party Transactions

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 June 30, 2016, Oxy owned approximately 13% 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 six months ended June 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues	$ 142	$ 382	$ 254	$ 558
Purchases and related costs (1)	$ (4)	$ 41	$ (50)	$ 146

(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 on our Condensed Consolidated Balance Sheets were as follows (in millions):

	June 30, 2016	December 31, 2015
Trade accounts receivable and other receivables	$ 495	$ 405
Accounts payable	$ 460	$ 363

Note 11 Commitments and Contingencies

Loss Contingencies General

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

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

Legal Proceedings General

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

Table of Contents

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

Environmental General

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

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

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

At June 30, 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 $59 million was classified as short-term and $101 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 June 30, 2016, we had recorded receivables totaling $68 million for amounts probable of recovery under insurance and from third parties under indemnification agreements, of which $46 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 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.

Table of Contents

As a result of the Line 901 incident, several governmental agencies and regulators have 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. On June 3, 2015, the corrective action order was amended to require us to take additional corrective actions with respect to both Lines 901 and 903. On November 13, 2015, the corrective action order was further amended to require the purge and shutdown of Line 903 between Gaviota and Pentland. On June 16, 2016, the corrective action order was further amended to require additional corrective actions and documentation with respect to both Line 901and Line 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 California law in connection with the Line 901 incident. The indictment included a total 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, seven 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.

Table of Contents

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 which were filed in the United States District Court for the Southern District of Texas have been administratively consolidated into one action and the other 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.

In addition to the foregoing, as the responsible party for the Line 901 incident we are liable for various costs and for certain natural resource damages under the Oil Pollution Act, and we also have exposure to the payment of additional fines, penalties and costs under other applicable federal, state and local laws, statutes and regulations. To the extent any such costs are reasonably estimable, we have included an estimate of such costs in the loss accrual described below.

Taking the foregoing into account, as of June 30, 2016, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $269 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.

Table of Contents

As of June 30, 2016, we had a remaining undiscounted gross liability of $91 million related to this event, of which approximately $51 million is presented as a current liability in Accounts payable and accrued liabilities on our Condensed Consolidated Balance Sheet, with the remainder presented in Other long-term liabilities and deferred credits . We maintain insurance coverage, which is subject to certain exclusions and deductibles, in the event of such environmental liabilities. Subject to such exclusions and deductibles, we believe that our coverage is adequate to cover the current estimated total emergency response and clean-up costs, claims settlement costs and remediation costs and we believe that this coverage is also adequate to cover any potential increase in the estimates for these costs that exceed the amounts currently identified. Through June 30, 2016, we had collected, subject to customary reservations, $124 million out of the approximate $186 million of release costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of June 30, 2016, we have recognized a receivable of approximately $62 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 $42 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.

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.

Table of Contents

Note 12 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):

Three Months Ended June 30, 2016	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External customers	$ 170	$ 132	$ 4,648	$ 4,950
Intersegment (1)	233	138	4	375
Total revenues of reportable segments	$ 403	$ 270	$ 4,652	$ 5,325
Equity earnings in unconsolidated entities	$ 40	$	$	$ 40
Segment profit/(loss) (2) (3)	$ 252	$ 156	$ (18)	$ 390
Maintenance capital	$ 23	$ 9	$ 3	$ 35

Three Months Ended June 30, 2015	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External customers	$ 180	$ 137	$ 6,346	$ 6,663
Intersegment (1)	222	132	5	359
Total revenues of reportable segments	$ 402	$ 269	$ 6,351	$ 7,022
Equity earnings in unconsolidated entities	$ 52	$	$	$ 52
Segment profit (2) (3)	$ 186	$ 144	$ 41	$ 371
Maintenance capital	$ 33	$ 17	$ 2	$ 52

Six Months Ended June 30, 2016	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External customers	$ 323	$ 270	$ 8,467	$ 9,060
Intersegment (1)	464	265	6	735
Total revenues of reportable segments	$ 787	$ 535	$ 8,473	$ 9,795
Equity earnings in unconsolidated entities	$ 87	$	$	$ 87
Segment profit (2) (3)	$ 499	$ 315	$ 19	$ 833
Maintenance capital	$ 57	$ 18	$ 6	$ 81

Six Months Ended June 30, 2015	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External customers	$ 366	$ 261	$ 11,978	$ 12,605

Intersegment (1)		437		264		6		707
Total revenues of reportable segments	$	803	$	525	$	11,984	$	13,312
Equity earnings in unconsolidated entities	$	89	$		$		$	89
Segment profit (2) (3)	$	428	$	285	$	171	$	884
Maintenance capital	$	66	$	32	$	4	$	102

(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.

Table of Contents

(2) Supply and Logistics segment profit includes interest expense (related to hedged inventory purchases) of $3 million and $2 million for the three months ended June 30, 2016 and 2015, respectively, and $6 million and $3 million for the six months ended June 30, 2016 and 2015, respectively.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Segment profit	$ 390	$ 371	$ 833	$ 884
Depreciation and amortization	(204)	(108)	(319)	(212)
Interest expense, net	(114)	(107)	(227)	(212)
Other income/(expense), net	25	1	30	(3)
Income before tax	97	157	317	457
Income tax benefit/(expense)	5	(33)	(13)	(49)
Net income	102	124	304	408
Net income attributable to noncontrolling interests	(1)		(2)	(1)
Net income attributable to PAA	$ 101	$ 124	$ 302	$ 407

Note 13 Acquisitions, Dispositions and Impairments

Acquisitions. During the first six months of 2016, we completed one acquisition for cash consideration of $85 million. We did not recognize any goodwill related to this acquisition. In addition, 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, including $51 million for inventory and working capital.

Dispositions and Divestitures. During the six months ended June 30, 2016, we sold several non-core assets, including certain of our Gulf of Mexico pipelines and East Coast refined products terminals. In addition, in June 2016 we sold 50% of our investment in Cheyenne Pipeline LLC. We recognized gains of approximately $71 million and losses of $55 million related to these sales, including $15 million of impairment of goodwill that was included in a disposal group classified as held for sale as of March 31, 2016. These gains and losses are included in Depreciation and amortization on our Condensed Consolidated Statement of Operations.

As of June 30, 2016, we classified approximately $152 million of assets as held for sale on our Condensed Consolidated Balance Sheet (in Other current assets) related to definitive agreements to sell additional non-core assets, a majority of which are included in our Transportation segment. A portion of these transactions closed in July 2016, and we expect the sale of the remaining assets to be consummated later in the third quarter of 2016, 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 14 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 June 30, 2016, approximately $593 million), 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), both PAA and PAGP will continue to be publicly traded.

Table of Contents

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 outstanding AAP units, 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.

29

Table of Contents

It is anticipated that the Simplification Transactions will be consummated during the fourth quarter of 2016. Pursuant to the terms of the Simplification Agreement, AAP has agreed that if such closing does not occur prior to the record date for PAA s distribution of available cash in respect of the third quarter of 2016 and the amount of such distribution is below the current 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. Based on the previously announced intent of PAA to reduce its quarterly distribution to $0.55 per common unit commencing with its third quarter distribution, it is estimated that the potential incremental borrowings that would be made by AAP if the closing of the Simplification Transactions does not take place by the record date for PAA s third quarter distribution will be approximately $41 million.

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.

The consummation of the matters contemplated by the Simplification Agreement is subject to customary closing conditions and may be terminated under certain conditions.

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 six months ended June 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 June 30, 2016	Six Months Ended June 30, 2016
Net income attributable to PAA	$ 98	$ 296
Basic net income per common unit	$ 0.10	$ 0.37
Diluted net income per common unit	$ 0.10	$ 0.37

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

	As of

		June 30, 2016
LONG-TERM LIABILITIES		
Other long-term debt, net of unamortized debt issuance costs	$	962
PARTNERS CAPITAL		
Common unitholders	$	6,799
General partner	$	
Total partners capital	$	8,366

Table of Contents

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 six months of 2016, we recognized net income attributable to PAA of $302 million as compared to net income attributable to PAA of $407 million recognized during the first six 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 and impacts from the mark-to-market loss related to derivative instruments during the periods;

- 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 recently completed 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) assets taken out of service, all partially offset by net gains related to non-core assets sales completed during the period;

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

31

Table of Contents

- Gains of approximately $25 million recognized during the six months ended June 30, 2016 relating 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 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 $709 million in midstream infrastructure projects during the six months ended June 30, 2016, with a targeted expansion capital plan for the full year of 2016 of approximately $1.425 billion. To fund such capital activities, we have 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 and (ii) the sale of various assets for net proceeds of approximately $305 million, primarily related to our planned non-core asset sales initiative. In addition, during July 2016 we completed the sale of additional non-core assets for net proceeds of approximately $170 million, and 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, including $51 million for inventory and working capital.

Additionally, we paid $866 million of cash distributions to our common unitholders and general partner during the six months ended June 30, 2016, and we declared a quarterly distribution of $0.70 per common unit to be paid on August 12, 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 June 30, 2016, approximately $593 million), 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 in the fourth quarter of 2016, subject to customary closing conditions. See Note 14 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):

	Six Months Ended June 30,	
	2016	2015
Acquisition capital (1)	$ 85	$ 64
Expansion capital (1) (2)	709	1,188
Maintenance capital (2)	81	102
	$ 875	$ 1,354

(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.

(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.

Table of Contents

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	190
Permian Basin Area Pipeline Projects	185
Diamond Pipeline	165
Saddlehorn Pipeline	125
Cushing Terminal Expansions	60
St. James Terminal Expansions	45
Caddo Pipeline	35
Cactus Pipeline	20
Eagle Ford JV Project	20
Other Projects	270
	$1,425
Potential Adjustments for Timing / Scope Refinement (1)	-$75 +$75
Total Projected Expansion Capital Expenditures	$1,350 - $1,500
Maintenance Capital Expenditures	$180 - $200

(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 12 to our Condensed Consolidated Financial Statements for additional information regarding our operating segments and segment performance measures.

	Three Months Ended June 30,		**Favorable/ (Unfavorable) Variance**		**Six Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**	
	2016	**2015**	**$**	**%**	**2016**	**2015**	**$**	**%**
Transportation segment profit	$ 252	$ 186	$ 66	35%	$ 499	$ 428	$ 71	17%
Facilities segment profit	156	144	12	8%	315	285	30	11%
Supply and Logistics segment profit/(loss)	(18)	41	(59)	(144)%	19	171	(152)	(89)%
Total segment profit	390	371	19	5%	833	884	(51)	(6)%

Depreciation and amortization	(204)	(108)	(96)	(89)%	(319)	(212)	(107)	(50)%
Interest expense, net	(114)	(107)	(7)	(7)%	(227)	(212)	(15)	(7)%
Other income/(expense), net	25	1	24	**	30	(3)	33	**
Income tax benefit/(expense)	5	(33)	38	115%	(13)	(49)	36	73%
Net income	102	124	(22)	(18)%	304	408	(104)	(25)%
Net income attributable to noncontrolling interests	(1)		(1)	NA	(2)	(1)	(1)	(100)%
Net income attributable to PAA	$ 101	$ 124	$ (23)	(19)%	$ 302	$ 407	$ (105)	(26)%
Basic net income/(loss) per common unit	$ (0.20)	$ (0.06)	$ (0.14)	(233)%	$ (0.13)	$ 0.29	$ (0.42)	(145)%
Diluted net income/(loss) per common unit	$ (0.20)	$ (0.06)	$ (0.14)	(233)%	$ (0.13)	$ 0.29	$ (0.42)	(145)%
Basic weighted average common units outstanding	398	397	1	%	398	390	8	2%
Diluted weighted average common units outstanding	398	397	1	%	398	393	5	1%

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

Table of Contents

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

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

	Three Months Ended June 30,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
	2016	2015	$	%	2016	2015	$	%
Net income	$ 102	$ 124	$ (22)	(18)%	$ 304	$ 408	$ (104)	(25)%
Add:								
Interest expense, net	114	107	7	7%	227	212	15	7%
Income tax (benefit)/expense	(5)	33	(38)	(115)%	13	49	(36)	(73)%
Depreciation and amortization	204	108	96	89%	319	212	107	50%
EBITDA	$ 415	$ 372	$ 43	12%	$ 863	$ 881	$ (18)	(2)%
Selected Items Impacting Comparability of EBITDA:								
Losses from derivative activities net of inventory valuation	$ (93)	$ (60)	$ (33)	(55)%	$ (216)	$ (151)	$ (65)	(43)%

adjustments (1)								
Long-term inventory costing adjustments (2)	67	23	44	191%	44	(15)	59	393%
Deficiencies under minimum volume commitments, net (3)	(8)		(8)	N/A	(34)		(34)	N/A
Equity-indexed compensation expense (4)	(11)	(11)		%	(15)	(22)	7	32%
Net gain/(loss) on foreign currency revaluation (5)	(1)	(1)		%	2	26	(24)	(92)%
Line 901 incident (6)		(65)	65	100%		(65)	65	100%
Selected Items Impacting Comparability of EBITDA	$ (46)	$ (114)	$ 68	60%	$ (219)	$ (227)	$ 8	4%

Table of Contents

	Three Months Ended June 30,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
	2016	2015	$	%	2016	2015	$	%
EBITDA	$ 415	$ 372	$ 43	12%	$ 863	$ 881	$ (18)	(2)%
Selected Items Impacting Comparability of EBITDA	46	114	(68)	(60)%	219	227	(8)	(4)%
Adjusted EBITDA	$ 461	$ 486	$ (25)	(5)%	$ 1,082	$ 1,108	$ (26)	(2)%
Interest expense, net (7)	(110)	(104)	(6)	(6)%	(219)	(204)	(15)	(7)%
Maintenance capital (8)	(35)	(52)	17	33%	(81)	(102)	21	21%
Current income tax expense	(9)	(19)	10	53%	(40)	(61)	21	34%
Equity earnings in unconsolidated entities, net of distributions	8	(3)	11	367%	14	13	1	8%
Distributions to noncontrolling interests (9)	(1)	(1)		%	(2)	(2)		%
Implied DCF (10)	$ 314	$ 307	$ 7	2%	$ 754	$ 752	$ 2	%
Less: Cash Distributions (9)	(433)	(428)			(866)	(848)		
DCF Excess/(Shortage) (11)	$ (119)	$ (121)			$ (112)	$ (96)		

(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.

Table of Contents

(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 11 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 three and six months ended June 30, 2015, Implied DCF would have been $242 million and $687 million for the three and six months ended June 30, 2015, respectively. See Note 11 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 12 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.

Table of Contents

Transportation Segment

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. The Transportation segment generates revenue through a combination of tariffs, third-party pipeline capacity agreements and other transportation fees.

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

Operating Results (1) (in millions, except per barrel data)	Three Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance $	%	Six Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance $	%
Revenues								
Tariff activities	$ 365	$ 361	$ 4	1%	$ 715	$ 720	$ (5)	(1)%
Trucking	38	41	(3)	(7)%	72	83	(11)	(13)%
Total transportation revenues	403	402	1	%	787	803	(16)	(2)%
Costs and expenses								
Trucking costs	(24)	(29)	5	17%	(45)	(59)	14	24%
Field operating costs (2)	(136)	(209)	73	35%	(274)	(346)	72	21%
Equity-indexed compensation expense - operations	(5)	(3)	(2)	(67)%	(5)	(6)	1	17%
Segment general and administrative expenses (2) (3)	(21)	(22)	1	5%	(44)	(43)	(1)	(2)%
Equity-indexed compensation expense - general and administrative	(5)	(5)		%	(7)	(10)	3	30%
Equity earnings in unconsolidated entities	40	52	(12)	(23)%	87	89	(2)	(2)%
Segment profit	$ 252	$ 186	$ 66	35%	$ 499	$ 428	$ 71	17%
Maintenance capital	$ 23	$ 33	$ 10	30%	$ 57	$ 66	$ 9	14%
Segment profit per barrel	$ 0.58	$ 0.45	$ 0.13	29%	$ 0.58	$ 0.54	$ 0.04	7%

Average Daily Volumes (in thousands of barrels per day) (4)	Three Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance Volumes	%	Six Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance Volumes	%
Tariff activities volumes								
Crude oil pipelines (by region):								
Permian Basin (5)	2,178	1,886	292	15%	2,112	1,773	339	19%
South Texas / Eagle Ford (5)	274	308	(34)	(11)%	294	286	8	3%
Western	211	207	4	2%	193	237	(44)	(19)%
Rocky Mountain (5)	431	426	5	1%	434	439	(5)	(1)%
Gulf Coast	613	575	38	7%	597	508	89	18%
Central	398	432	(34)	(8)%	388	434	(46)	(11)%
Canada	379	392	(13)	(3)%	386	403	(17)	(4)%
Crude oil pipelines	4,484	4,226	258	6%	4,404	4,080	324	8%
NGL pipelines	182	194	(12)	(6)%	180	192	(12)	(6)%
Tariff activities total volumes	4,666	4,420	246	6%	4,584	4,272	312	7%
Trucking	115	109	6	6%	110	115	(5)	(4)%

Transportation segment total volumes	4,781	4,529	252	6%	4,694	4,387	307	7%

(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.

Table of Contents

(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 were relatively consistent for the three and six months ended June 30, 2016 compared to the same 2015 periods, while volumes increased for both comparative periods presented. Equity earnings in unconsolidated entities decreased for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015.

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 June 30, 2016-2015		Favorable/(Unfavorable) Variance Six Months Ended June 30, 2016-2015	
(in millions)	**Revenues**	**Equity Earnings**	**Revenues**	**Equity Earnings**
Tariff activities:				
Permian Basin region	$ 26	$ (9)	$ 58	$ (2)
South Texas/Eagle Ford region	(1)	(3)	(2)	2
Western region			(11)	

Gulf Coast region	(3)		1	
Central region	(5)		(11)	
Canada crude oil pipelines	(3)		(10)	
Other (including pipeline loss allowance revenue)	(10)		(30)	(2)
Total variance	$ 4	$ (12)	$ (5)	$ (2)

- Permian Basin region The increase in revenues for the comparative 2016 periods presented was largely driven by (i) higher volumes associated with the expansion of our pipeline systems in the Delaware Basin and (ii) 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.

Equity earnings decreased for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 due to lower earnings from our interest in BridgeTex resulting from lower volumes. The unfavorable variance for the six-month period was partially offset by higher earnings during the first quarter of 2016 compared to the same period in 2015, as BridgeTex was in a ramp-up phase during the 2015 period and was not in full service until mid-2015.

- South Texas/Eagle Ford region Revenues and equity earnings decreased for the three months ended June 30, 2016 compared to the same 2015 period primarily due to lower volumes attributable to production declines. For the six month comparative period, the unfavorable equity earnings variance was offset by higher volumes on the Eagle Ford joint venture pipeline from the connection to our Cactus pipeline in April 2015.

- Western region Revenues and volumes for the three and six months ended June 30, 2016 were unfavorably impacted by pipeline downtime on our All American Pipeline associated with the Line 901 incident that occurred in the second quarter of 2015. See Note 11 to our Condensed Consolidated Financial Statements for additional information regarding the Line 901 incident. Such unfavorable variances were partially offset by higher volumes on certain of our West Coast pipelines during the second quarter of 2016, which benefited from volume diversions resulting from a temporary third-party pipeline shutdown.

Table of Contents

- Gulf Coast region Revenues decreased for the three months ended June 30, 2016 compared to the same 2015 period primarily due to the sale of certain of our Gulf Coast pipelines in March 2016. This decrease was partially offset by (i) our purchase of the remaining interest in the CAM pipeline, which was subsequently sold in July 2016 and (ii) 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 six months ended June 30, 2016 versus the comparable 2015 periods was largely driven by lower volumes due to production declines in the Mid-Continent area.

- Canada crude oil pipelines Revenues decreased for the three and six months ended June 30, 2016 compared to the same 2015 periods primarily due to unfavorable foreign exchange impacts of $3 million and $10 million, respectively, and lower volumes from production declines, which offset revenue increases from higher tariff rates on certain of our pipelines and related system assets.

- Other The decrease in other revenues for the three and six months ended June 30, 2016 was primarily related to lower pipeline loss allowance revenue of $11 million and $29 million, respectively, driven by a lower average realized price per barrel.

Trucking Revenues. The decrease in trucking revenues for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 was largely due to unfavorable foreign exchange impacts of $2 million and $6 million, respectively. The six-month 2016 period was further negatively impacted by lower volumes due to reduced drilling and declining volumes from existing producers.

Trucking Costs. Trucking costs decreased for the three and six months ended June 30, 2016 compared to the same 2015 periods due to lower contract services rates and decreased volumes, as well as favorable foreign exchange impacts of $1 million and $4 million for the three and six month comparative periods, respectively.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the three and six months ended June 30, 2016 compared to the three and six months ended June 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 11 to our Condensed Consolidated Financial Statements for additional information regarding the Line 901 incident. The decrease was further driven by lower utilities and maintenance costs as well as favorable foreign exchange impacts of $2 million and $5 million for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015, respectively. The decrease for the six month comparative periods was partially offset by an increase in integrity management costs.

Equity-Indexed Compensation Expense. On a consolidated basis, equity-indexed compensation expense increased by $5 million for the three months ended June 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 June 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 units outstanding and lower values per unit during the 2016 period compared to the same period in 2015.

On a consolidated basis across all segments, equity-indexed compensation expense decreased by $10 million for the six months ended June 30, 2016 compared to the same period in 2015, primarily due to the impact of fewer units outstanding and lower values per unit during the six months ended June 30, 2016 compared to the same period in 2015, partially offset by the impact of the increase in unit price during the six months ended June 30, 2016 compared to the impact of the decrease in unit price during 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 maintenance capital for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 was primarily driven by lower third party service costs and timing of projects.

Table of Contents

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) (in millions, except per barrel data)	Three Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance $	%	Six Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance $	%
Revenues	$ 270	$ 269	$ 1	%	$ 535	$ 525	$ 10	2%
Natural gas related storage costs	(6)	(7)	1	14%	(11)	(11)		%
Field operating costs (2)	(88)	(97)	9	9%	(173)	(187)	14	7%
Equity-indexed compensation expense - operations	(2)	(1)	(1)	(100)%	(2)	(2)		%
Segment general and administrative expenses (2) (3)	(14)	(17)	3	18%	(30)	(33)	3	9%
Equity-indexed compensation expense - general and administrative	(4)	(3)	(1)	(33)%	(4)	(7)	3	43%
Segment profit	$ 156	$ 144	$ 12	8%	$ 315	$ 285	$ 30	11%
Maintenance capital	$ 9	$ 17	$ 8	47%	$ 18	$ 32	$ 14	44%
Segment profit per barrel	$ 0.41	$ 0.38	$ 0.03	8%	$ 0.41	$ 0.38	$ 0.03	8%

Volumes (4)	Three Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance Volumes	%	Six Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance Volumes	%
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	105	99	6	6%	105	99	6	6%
Rail load / unload volumes (average volumes in thousands of barrels per day)	127	233	(106)	(45)%	109	220	(111)	(50)%
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)	105	103	2	2%	110	103	7	7%
Facilities segment total (average monthly volumes in millions of barrels) **(5)**	128	126	2	2%	128	125	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.

Table of Contents

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 were relatively consistent for the three months ended June 30, 2016 compared to the three months ended June 30, 2015, and increased by $10 million for the comparable six month period. Total volumes increased slightly for both comparative periods presented. Our Facilities segment results for the comparative periods were impacted by:

- Crude Oil Storage Revenues increased by $4 million and $18 million for the three and six months ended June 30, 2016, respectively, as compared to the three and six months ended June 30, 2015 primarily due to increased utilization at certain of our West Coast terminals and aggregate capacity expansions of approximately 4 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 $7 million and $15 million for the three and six month comparative periods, respectively, primarily due to lower volumes at our U.S. terminals as a result of less favorable market conditions, partially offset by revenues and volumes from our Canadian rail terminal that came online in April 2016.

- NGL Storage, NGL Fractionation and Canadian Natural Gas Processing Revenues increased by $7 million for both the three and six months ended June 30, 2016 compared to the same periods in 2015, primarily due to higher fees and increased capacity at certain of our NGL storage and fractionation facilities, which more than offset unfavorable foreign exchange impacts of approximately $3 million and $10 million for the comparative three and six month periods, respectively.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the three and six months ended June 30, 2016 compared to the three and six months ended June 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. The decrease in field operating costs was also impacted by lower utilities costs as well as favorable foreign exchange impacts of $2 million and $5 million, respectively, for the three and six month comparative periods. These decreases were partially offset by employee severance costs associated with personnel reductions related to the restructuring of certain of our operations.

Maintenance Capital. The decrease in maintenance capital for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 was primarily due to lower spending on various tank and other maintenance capital projects, partially due to timing.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes purchased from suppliers and natural gas sales attributable to the activities 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) demand for lease gathering services we provide producers 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.

Table of Contents

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

Operating Results (1) (in millions, except per barrel data)	Three Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance $	%	Six Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance $	%
Revenues	$ 4,652	$ 6,351	$ (1,699)	(27)%	$ 8,473	$ 11,984	$ (3,511)	(29)%
Purchases and related costs (2)	(4,566)	(6,168)	1,602	26%	(8,243)	(11,521)	3,278	28%
Field operating costs (3)	(74)	(110)	36	33%	(155)	(227)	72	32%
Equity-indexed compensation expense - operations	(1)		(1)	N/A	(1)	(1)		%
Segment general and administrative expenses (3) (4)	(24)	(27)	3	11%	(48)	(54)	6	11%
Equity-indexed compensation expense - general and administrative	(5)	(5)		%	(7)	(10)	3	30%
Segment profit/(loss)	$ (18)	$ 41	$ (59)	(144)%	$ 19	$ 171	$ (152)	(89)%
Maintenance capital	$ 3	$ 2	$ (1)	(50)%	$ 6	$ 4	$ (2)	(50)%
Segment profit per barrel	$ (0.18)	$ 0.40	$ (0.58)	(145)%	$ 0.09	$ 0.79	$ (0.70)	(89)%

Average Daily Volumes (in thousands of barrels per day)	Three Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance Volumes	%	Six Months Ended June 30, 2016	2015	Favorable/ (Unfavorable) Variance Volumes	%
Crude oil lease gathering purchases	885	967	(82)	(8)%	899	974	(75)	(8)%
NGL sales	176	158	18	11%	242	222	20	9%
Waterborne cargos	5		5	N/A	6		6	N/A
Supply and Logistics segment total	1,066	1,125	(59)	(5)%	1,147	1,196	(49)	(4)%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of $3 million and $2 million for the three months ended June 30, 2016 and 2015, respectively, and $6 million and $3 million for the six months ended June 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):

	NYMEX WTI Crude Oil Price	
	Low	High
Three months ended June 30, 2016	$ 36	$ 51
Three months ended June 30, 2015	$ 49	$ 61
Six months ended June 30, 2016	$ 26	$ 51
Six months ended June 30, 2015	$ 43	$ 61

Table of Contents

Because the commodities that we buy and sell are generally indexed to the same pricing indices for both sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases decreased for the three and six months ended June 30, 2016 compared to the same periods in 2015 due to lower crude oil and NGL prices.

Generally, we expect a base level of earnings from our Supply and Logistics segment from the assets employed by this segment. This base level may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. During certain transitional periods, such as this extended period of lower crude oil prices, the ability to generate above base level earnings is challenging, and taking into account the over-capacity of midstream assets and increased competition that currently exists in most crude oil producing regions, generating even baseline level performance is challenging. Also, our NGL operations are sensitive to weather-related demand, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on NGL demand and thus our financial performance.

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

Net Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs, decreased by $97 million and $233 million for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015. The following summarizes the more significant items impacting the comparative periods:

- Crude Oil Operations Net revenues from our crude oil supply and logistics activities decreased for the three and six months ended June 30, 2016 as compared to the same 2015 periods, primarily due to increased competition, largely due to overbuilt infrastructure and volume declines in certain areas, that have negatively impacted our lease gathering unit margins.

- NGL Operations Net revenues from our NGL operations decreased for the three and six months ended June 30, 2016 as compared to the three and six months ended June 30, 2015, primarily due to softer propane sales margins during the 2015-2016 winter heating season resulting from a shorter and milder winter, as well as higher storage and processing fees for the 2016 periods.

- Foreign Exchange Impacts Our results are impacted by fluctuations in the value of CAD to USD, resulting in foreign exchange gains and losses on U.S. denominated net assets within our Canadian operations. The changes in exchange rates during each period resulted in a favorable variance of $2 million for the three months ended June 30, 2016 compared to the three months ended June 30, 2015, and an unfavorable variance of $31 million for the six months ended June 30, 2016 compared to the six months ended June 30, 2015.

Furthermore, the depreciation of CAD relative to USD resulted in lower USD costs of approximately $5 million and $15 million for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015, respectively. Such costs were primarily associated with intercompany facility fees and were largely offset in our Facilities segment results.

- Impact from Certain Derivative Activities, Net of Inventory Valuation Adjustments The mark-to-market of certain of our derivative activities impacted our net revenues as shown in the table below (in millions):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Variance	2016	2015	Variance
Losses from certain derivative activities net of inventory valuation adjustments (1)	$ (124)	$ (66)	$ (58)	$ (248)	$ (159)	$ (89)

(1) Includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in another period (or the reversal of mark-to-market gains and losses from a prior period), gains and losses on certain derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable. See Note 9 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

Table of Contents

- Long-Term Inventory Costing Adjustment Our operating results are impacted by changes in the weighted average cost of our crude oil and NGL inventory pools that result from price movements during the periods. Such costing adjustments resulted in favorable impacts of $67 million and $23 million for the three months ended June 30, 2016 and 2015, respectively, and favorable impacts of $44 million and unfavorable impacts of $15 million for the six months ended June 30, 2016 and 2015, respectively, due to price changes during each period. These costing adjustments related to long-term inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that was needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future.

Field Operating Costs. The decrease in field operating costs (excluding equity-indexed compensation expense) for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 was primarily due to a combination of (i) lower lease gathering volumes, (ii) shorter truck hauls as pipeline expansion projects were placed into service and (iii) a decrease in fuel prices.

General and Administrative Expenses. The decrease in general and administrative expenses (excluding equity-indexed compensation expense) for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 was primarily due to lower salary and other personnel costs.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense increased for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 primarily due to (i) impairment losses of approximately $80 million associated with certain of our rail and other terminal assets, (ii) an approximately $18 million charge related to assets taken out of service, (iii) additional depreciation expense associated with various capital expansion projects completed since the 2015 periods and (iv) the write-off of costs associated with the discontinuation of certain projects during 2016. These increases were partially offset by net gains of approximately $10 million and $16 million recognized during the three and six months ended June 30, 2016, respectively, which were primarily associated with non-core asset sales during the periods.

Interest Expense

The increase in interest expense for the three and six months ended June 30, 2016 over the three and six months ended June 30, 2015 was primarily due to a higher weighted average debt balance largely driven by our August 2015 $1.0 billion senior note issuance, partially offset by the maturity of $150 million and $400 million of our senior notes in June 2015 and September 2015, respectively.

Other Income/(Expense), Net

Other income/(expense), net for the three and six months ended June 30, 2016 was impacted by a gain of $25 million related to the mark-to-market adjustment of our Preferred Distribution Rate Reset Option. See Note 9 to our Condensed Consolidated Financial Statements for additional information. Excluding such gain, Other income/(expense), net in each of the periods presented was primarily comprised of foreign currency gains or losses related to revaluations of CAD-denominated interest receivables associated with our intercompany notes.

Income Tax Expense

Income tax expense decreased for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 primarily due to deferred tax expense recorded in the second quarter of 2015 related to the cumulative revaluation of Canadian net deferred tax liabilities resulting from a 2% Alberta, Canada provincial tax rate increase and lower year-over-year taxable earnings from our Canadian operations.

Outlook

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays, which occurred contemporaneously with attractive crude oil and liquids prices, during the approximately three year period through the end of 2014, U.S. crude oil and liquids production in the lower 48 states increased rapidly. This was particularly true for light crudes and condensates. Similar resource development activities in Canada and ongoing oil sands development activities also led to increased Canadian crude oil production during this period. Additionally, during this period, the crude oil market experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude oil qualities, international supply issues, and

Table of Contents

regional downstream operating issues. During 2013 and to a lesser degree 2014, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment.

However, the combination during such period of surging North American liquids production, relatively flat liquids production for the rest of the world and relatively modest growth in global liquids demand led to a supply imbalance, which in turn led to a significant and rapid reduction in petroleum prices. While we believe that our business model and asset base have minimal direct exposure to petroleum prices, our performance is influenced by certain differentials and overall North American production levels, which in turn are impacted by major price movements. The meaningful decrease in crude oil price levels during the second half of 2014 and throughout 2015 relative to the levels experienced during 2013 and the first half of 2014 have led many producers, including North American producers, to significantly scale back capital programs. As a result, during 2015 and through the second quarter of 2016, the rate of growth of North American crude oil production slowed significantly and began to decrease in some areas as producers have taken rigs out of service and deferred completions at an increased rate. The pace and depth of the reduction in drilling and completion activities by producers has been greater than anticipated by many market participants and observers; since the beginning of 2015, onshore rig counts for the lower 48 States have decreased approximately 75%. As a result of the combined effect of such reduced activity levels and the high decline rates for many of the producing wells that contribute towards current lower 48 onshore production levels, crude oil production declines are expected to continue during 2016 and potentially beyond in a number of onshore plays. While we believe that the larger North American resource base remains intact and will ultimately be developed, such production will likely take place at a slower pace and previously anticipated peak production levels will likely be reduced. This slowdown and reduction in North American production coupled with past increases in infrastructure has led to a compression of basis differentials in a number of locations. This transitioning crude oil market presents challenges to our business model and asset base and will likely impact the rate of cash flow and distribution growth that we would have otherwise experienced over the next several years. In addition, increased competition and compressed differentials may drive lower volumes and lower unit margins in parts of our business, particularly our Supply and Logistics segment.

While we believe that these recent market developments will continue to impede crude oil supply growth and contribute toward bringing the markets back to equilibrium, there can be no assurance that such equilibrium will be achieved or that we will not be negatively impacted by declining crude oil supply, low levels of volatility or challenging capital markets conditions. Additionally, construction of additional infrastructure by us and our competitors will likely lead to even greater levels of excess takeaway capacity in certain areas for the near to medium term, which could further reduce unit margins in our various segments, and which could be exacerbated by declining levels of crude oil production. Finally, we cannot be certain that our expansion efforts will generate targeted returns or that any future acquisition activities will be successful. See Risk Factors Risks Related to Our Business discussed in Item 1A of our 2015 Annual Report on Form 10-K.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities, (ii) borrowings under our credit facilities or commercial paper program and (iii) funds received from sales of equity and debt securities. Our primary cash requirements include, but are not limited to, (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products and other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under our commercial paper program or credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing our long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional equity or debt securities. As of June 30, 2016, we had a working capital deficit of $426 million and approximately $2.9 billion of liquidity available to meet our ongoing operating, investing and financing needs,

subject to continued covenant compliance, as noted below (in millions):

		As of June 30, 2016
Availability under senior unsecured revolving credit facility (1) (2)	$	1,583
Availability under senior secured hedged inventory facility (1) (2)		817
Availability under senior unsecured 364-day revolving credit facility		1,000
Amounts outstanding under commercial paper program		(526)
Subtotal		2,874
Cash and cash equivalents		34
Total	$	2,908

Table of Contents

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

(2) Available capacity under the senior unsecured revolving credit facility and the senior secured hedged inventory facility was reduced by outstanding letters of credit of $17 million and $31 million, respectively.

We believe that we have, and will continue to have, the ability to access the commercial paper program and credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains solid and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A. Risk Factors of our 2015 Annual Report on Form 10-K for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities, which provide the backstop for the commercial paper program, is subject to ongoing compliance with covenants. As of June 30, 2016, we were in compliance with all such covenants.

Cash Flow from Operating Activities

For a comprehensive discussion of the primary drivers of cash flow from operating activities, including the impact of varying market conditions and the timing of settlement of our derivatives, see Item 7. Liquidity and Capital Resources Cash Flow from Operating Activities included in our 2015 Annual Report on Form 10-K.

Net cash provided by operating activities for the first six months of 2016 and 2015 was $387 million and $660 million, respectively, and primarily resulted from earnings from our operations. Additionally, as discussed further below, changes in our inventory levels during these periods impacted our cash flow from operating activities.

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

During the six months ended June 30, 2015, we increased the volume of crude oil inventory that we held, primarily as a result of purchasing and storing such inventory due to contango market conditions. These increases were primarily funded with proceeds received from the seasonal sale of our NGL and natural gas inventory and thus did not significantly impact cash provided by operating activities during the period.

Minimum Volume Commitments. We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Some of these agreements include make-up rights if the minimum volume is not met. At June 30, 2016, counterparty deficiencies associated with agreements that include minimum volume commitments totaled $70 million. We record a receivable from the counterparty in the period that services are

provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty s ability to utilize the make-up right is remote. Deferred revenue associated with non-performance under minimum volume contracts could be significant and could adversely affect our profitability and earnings, but generally does not impact our liquidity.

As of June 30, 2016, we had deferred revenue associated with minimum volume commitments of $45 million. In addition to the amounts recorded as deferred revenue, as of June 30, 2016, there was $25 million of accrued deficiencies for which the counterparties had not met their contractual minimum commitments, but we had not yet billed or collected such amounts.

Acquisitions, Capital Expenditures and Divestitures

In addition to our operating needs discussed above, we also use cash for our acquisition activities and capital projects. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital.

Acquisitions and Divestitures. During the six months ended June 30, 2016 and 2015, we paid cash of $85 million and $64 million, respectively, for acquisitions. In addition, during the first half of 2016, we completed the sale of various non-core assets, as well as the sale of 50% of our investment in Cheyenne Pipeline LLC, for cash proceeds of $391 million. We also completed an additional divestiture of non-core assets in July 2016 for approximately $170 million.

Table of Contents

In addition, in August 2016, we completed the acquisition of an integrated system of NGL assets in Western Canada for a cash purchase price of approximately $204 million, including $51 million for inventory and working capital.

2016 Capital Projects. We invested approximately $709 million in midstream infrastructure during the six months ended June 30, 2016. See Acquisitions and Capital Projects for detail of our projected capital expenditures for the year ending December 31, 2016. We expect the majority of funding for our remaining 2016 capital program will be provided by the proceeds from our January 2016 Series A preferred unit offering, the sale of various non-core assets throughout the year and through the potential issuance of equity and long-term debt.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding expansion capital projects, acquisitions and refinancing of our debt maturities, as well as short-term working capital and hedged inventory borrowings related to our NGL business and contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities or commercial paper program, as well as payment of distributions to our unitholders and general partner.

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). At June 30, 2016, we had approximately $2.0 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. We did not conduct any offerings under our Traditional Shelf or under our WKSI Shelf during the six months ended June 30, 2016.

Series A Preferred Unit Issuance. In January 2016, we completed the private placement of approximately 61.0 million Series A preferred units at a price of $26.25 per unit resulting in total net proceeds to us, after deducting offering expenses and the 2% transaction fee due to the purchasers and including our 2% general partner s proportionate contribution, of approximately $1.6 billion. We used the net proceeds for capital expenditures, repayment of debt and general partnership purposes.

Our Series A preferred units rank senior to all classes or series of equity securities in us with respect to distribution rights. The holders of the Series A preferred units are entitled to receive quarterly distributions, subject to customary antidilution adjustments, of $0.525 per unit ($2.10 per unit annualized), commencing with the quarter ended March 31, 2016. With respect to any quarter ending on or prior to December 31, 2017, we may elect to pay distributions on the Series A preferred units in additional preferred units, in cash or a combination of both.

After two years, the Series A preferred units are convertible at the purchasers option into common units on a one-for-one basis, subject to certain conditions, and are convertible at our option in certain circumstances after three years. See Note 8 to our Condensed Consolidated Financial Statements for additional information regarding our Series A preferred units.

Credit Agreements, Commercial Paper Program and Indentures. Our credit agreements (which impact our ability to access our commercial paper program because they provide the backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. As of June 30, 2016, we were in compliance with the covenants contained in our credit agreements and indentures.

During the six months ended June 30, 2016, we had net repayments on our credit agreements and commercial paper program of $592 million. The net repayments resulted primarily from cash flow from operating activities and cash received from our equity activities, which offset borrowings during the period related to inventory purchases and margin balances required as part of our hedging activities.

During the six months ended June 30, 2015, we had net borrowings under our credit agreements and commercial paper program of $151 million. These net borrowings resulted primarily from funding needs for (i) internal capital projects, (ii) repayment of our $150 million, 5.25% senior notes that matured in June 2015 and (iii) other general partnership purposes.

Our $175 million, 5.88% senior notes will mature in August 2016, and our $400 million, 6.13% senior notes will mature in January 2017. We intend to use borrowings under our commercial paper program or our credit facilities to repay these senior notes when they mature.

Table of Contents

Distributions to Our Unitholders and General Partner

Distributions to our Series A preferred unitholders. On August 12, 2016, we will issue 1,237,765 additional Series A preferred units in lieu of paying a cash distribution of $33 million. See Note 8 to our Condensed Consolidated Financial Statements for details of distributions pertaining to the first six months of 2016.

Distributions to our common unitholders. We distribute 100% of our available cash within 45 days following the end of each quarter to common unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. Our available cash also includes cash on hand resulting from borrowings made after the end of the quarter. On August 12, 2016, we will pay a quarterly distribution of $0.70 per common unit. See Note 8 to our Condensed Consolidated Financial Statements for details of distributions paid during or pertaining to the first six months of 2016. Also, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Cash Distribution Policy included in our 2015 Annual Report on Form 10-K for additional discussion regarding distributions.

We believe that we have sufficient liquid assets, cash flow from operating activities and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, subject to business and operational risks that could adversely affect our cash flow. A prolonged material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

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 June 30, 2016, approximately $593 million), 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), both PAA and PAGP will continue to be publicly traded.

The Simplification Transactions are expected to close in the fourth quarter of 2016, subject to customary closing conditions. Additionally, in connection with the Simplification Transactions and effective with the third quarter distribution to be paid in November, we intend to pay a quarterly distribution of $0.55 per common unit ($2.20 per unit on an annualized basis). See Note 14 to our Condensed Consolidated Financial Statements for additional discussion of the Simplification Transactions.

These transactions are among consolidated subsidiaries of PAGP that are considered entities under common control. As such, in accordance with FASB guidance, these transactions will be recognized at carrying value. Additionally, the transactions will be accounted for as equity

transactions in accordance with FASB guidance.

Contingencies

For a discussion of contingencies that may impact us, see Note 11 to our Condensed Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years, with a limited number of contracts with remaining terms extending up to approximately ten years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. In addition, we enter into similar contractual obligations in conjunction with our natural gas operations. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with our counterparties (including giving effect to netting buy/sell contracts and those subject to a net settlement arrangement). We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

Table of Contents

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of June 30, 2016 (in millions):

	Remainder of 2016	2017	2018	2019	2020	2021 and Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 765	$ 847	$ 1,019	$ 1,236	$ 834	$ 11,041	$ 15,742
Leases (2)	102	190	163	137	117	474	1,183
Other obligations (3)	391	517	205	168	147	607	2,035
Subtotal	1,258	1,554	1,387	1,541	1,098	12,122	18,960
Crude oil, natural gas, NGL and other purchases (4)	3,340	3,187	2,263	1,775	1,468	5,104	17,137
Total	$ 4,598	$ 4,741	$ 3,650	$ 3,316	$ 2,566	$ 17,226	$ 36,097

(1) Includes debt service payments, interest payments due on senior notes, the commitment fee on assumed available capacity under our credit facilities, and long-term borrowings under our commercial paper program. Although there may be short-term borrowings under our credit facilities and commercial paper program, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the facilities or commercial paper program) in the amounts above.

(2) Leases are primarily for (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks, trailers and railcars. Includes both capital and operating leases as defined by FASB guidance.

(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements and (iii) non-cancelable commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity method investments. The transportation agreements include approximately $890 million associated with an agreement to transport crude oil on a pipeline that is owned by an equity method investee, in which we own a 50% interest. Our commitment to transport is supported by crude oil buy/sell agreements with third parties (including Oxy) with commensurate quantities.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during June 2016. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Additionally, we issue

letters of credit to support insurance programs, derivative transactions and construction activities. At June 30, 2016 and December 31, 2015, we had outstanding letters of credit of approximately $48 million and $46 million, respectively.

Off-Balance Sheet Arrangements

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

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For a discussion regarding our critical accounting policies and estimates, see Critical Accounting Policies and Estimates under Item 7 of our 2015 Annual Report on Form 10-K.

Table of Contents

FORWARD-LOOKING STATEMENTS

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

- declines in the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our assets, whether due to declines in production from existing oil and gas reserves, failure to develop or slowdown in the development of additional oil and gas reserves, whether from reduced cash flow to fund drilling or the inability to access capital, or other factors;

- the effects of competition;

- failure to implement or capitalize, or delays in implementing or capitalizing, on expansion projects;

- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);

- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;

- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;

- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;

- the currency exchange rate of the Canadian dollar;

- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;

- inability to recognize current revenue attributable to deficiency payments received from customers who fail to ship or move more than minimum contracted volumes until the related credits expire or are used;

- non-utilization of our assets and facilities;

- increased costs, or lack of availability, of insurance;

- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;

- the availability of, and our ability to consummate, acquisition or combination opportunities;

- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;

- the effectiveness of our risk management activities;

- shortages or cost increases of supplies, materials or labor;

- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;

Table of Contents

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

- risks related to the development and operation of our assets, including our ability to satisfy our contractual obligations to our customers;

- factors affecting demand for natural gas and natural gas storage services and rates;

- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and

- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Risk Factors discussed in Item 1A of our 2015 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

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

- *Crude oil*

We utilize crude oil derivatives to hedge commodity price risk inherent in our Supply and Logistics and Transportation segments. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory, and storage capacity utilization. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

- *Natural gas*

We utilize natural gas derivatives to hedge commodity price risk inherent in our Supply and Logistics and Facilities segments. Our objectives for these derivatives include hedging anticipated purchases and sales and managing our anticipated base gas requirements. We manage these exposures with various instruments including exchange-traded futures, swaps and options.

- *NGL and other*

We utilize NGL derivatives, primarily butane and propane derivatives, to hedge commodity price risk inherent in our Supply and Logistics segment. Our objectives for these derivatives include hedging anticipated purchases and sales and stored inventory. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

See Note 9 to our Condensed Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

Table of Contents

The fair value of our commodity derivatives and the change in fair value as of June 30, 2016 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil	$ (123)	$ (85)	$ 85
Natural gas	(3)	$	$
NGL and other	(26)	$ (33)	$ 33
Total fair value	$ (152)		

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term commodity prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time, we use interest rate derivatives to hedge interest rate risk associated with anticipated interest payments and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus are not subject to interest rate risk. Our variable rate debt outstanding at June 30, 2016, approximately $1.1 billion, was subject to interest rate re-sets of one week or less. The average interest rate on variable rate debt that was outstanding during the six months ended June 30, 2016 was 1.2%, based upon rates in effect during such period. The fair value of our interest rate derivatives was a liability of $155 million as of June 30, 2016. A 10% increase in the forward LIBOR curve as of June 30, 2016 would have resulted in an increase of $35 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of June 30, 2016 would have resulted in a decrease of $35 million to the fair value of our interest rate derivatives. See Note 9 to our Condensed Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives was a liability of $1 million as of June 30, 2016. A 10% increase in the exchange rate (USD-to-CAD) would have resulted in a decrease of $19 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would have resulted in an increase of $19 million to the fair value of our foreign currency derivatives. See Note 9 to our Condensed Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

Preferred Distribution Rate Reset Option

The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value in our Condensed Consolidated Balance Sheets. The valuation model utilized for this embedded derivative contains inputs including our common unit price, ten-year U.S. treasury rates and default probabilities to ultimately calculate the fair value of our Series A preferred units with and without the Preferred Distribution Rate Reset Option. The fair value of this embedded derivative was a liability of $35 million as of June 30, 2016. A 10% increase in the fair value would have an impact of $4 million. A 10% decrease in the fair value would also have an impact of $4 million. See Note 9 to our Condensed Consolidated Financial Statements for a discussion of embedded derivatives.

Table of Contents

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

Applicable SEC rules require an evaluation of the effectiveness of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our DCP as of June 30, 2016, the end of the period covered by this report, and, based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our DCP is effective.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting during the second quarter of 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

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

Table of Contents

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included under the caption Legal Proceedings General in Note 11 to our Condensed Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2015 Annual Report on Form 10-K. Those risks and uncertainties are not the only ones facing us and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the six months ended June 30, 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. The issuance of the Series A preferred units, in connection with the quarterly distribution for the Series A preferred units, was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. MINE SAFETY DISCLOSURES

None.

Item 5. **OTHER INFORMATION**

None.

Item 6. **EXHIBITS**

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

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PAA GP LLC,
its general partner

By: Plains AAP, L.P.,
its sole member

By: PLAINS ALL AMERICAN GP LLC,
its general partner

By: /s/ Greg L. Armstrong
Greg L. Armstrong,
Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC
(Principal Executive Officer)

August 8, 2016

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

August 8, 2016

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

August 8, 2016

Table of Contents

EXHIBIT INDEX

2.1*	Simplification Agreement, dated as of July 11, 2016, by and among PAA GP Holdings LLC, Plains GP Holdings, L.P., Plains All American GP LLC, Plains AAP, L.P., PAA GP LLC and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed July 14, 2016).
3.1	Fifth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of January 28, 2016 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed February 2, 2016).
3.2	Amendment No. 1 to the Fifth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of July 10, 2016 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed July 14, 2016).
3.3	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.4	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.5	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.6	Amendment No. 3 dated June 30, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.7 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.7	Amendment No. 4 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P (incorporated by reference to Exhibit 3.8 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.8	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	Amendment No. 1 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.10	Sixth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated October 21, 2013 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed October 25, 2013).
3.11	Amendment No. 1 dated January 28, 2016 to the Sixth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed February 2, 2016).
3.12	Seventh Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated October 21, 2013 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 25, 2013).
3.13	Amendment No. 1 dated December 31, 2013 to the Seventh Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed December 31, 2013).
3.14	

Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2006).

Table of Contents

3.15	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to our Annual Report on Form 10-K for the year ended December 31, 2006).
3.16	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to our Registration Statement on Form S-4, File No. 333-121168).
4.3	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed May 12, 2006).
4.4	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed October 30, 2006).
4.5	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed October 30, 2006).
4.6	Thirteenth Supplemental Indenture (Series A and Series B 6.50% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 23, 2008).
4.7	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 20, 2009).
4.8	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 4, 2009).
4.9	Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed January 11, 2011).
4.10	Twentieth Supplemental Indenture (3.65% Senior Notes due 2022) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed March 26, 2012).
4.11	Twenty-First Supplemental Indenture (5.15% Senior Notes due 2042) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed March 26, 2012).

Table of Contents

4.12	Twenty-Second Supplemental Indenture (2.85% Senior Notes due 2023) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed December 12, 2012).
4.13	Twenty-Third Supplemental Indenture (4.30% Senior Notes due 2043) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 12, 2012).
4.14	Twenty-Fourth Supplemental Indenture (3.85% Senior Notes due 2023) dated August 15, 2013, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 15, 2013).
4.15	Twenty-Fifth Supplemental Indenture (4.70% Senior Notes due 2044) dated April 23, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 29, 2014).
4.16	Twenty-Sixth Supplemental Indenture (3.60% Senior Notes due 2024) dated September 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 11, 2014).
4.17	Twenty-Seventh Supplemental Indenture (2.60% Senior Notes due 2019) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed December 11, 2014).
4.18	Twenty-Eighth Supplemental Indenture (4.90% Senior Notes due 2045) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 11, 2014).
4.19	Twenty-Ninth Supplemental Indenture (4.65% Senior Notes due 2025) dated August 24, 2015, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 26, 2015).
4.20	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to our Registration Statement on Form S-3, File No. 333-162477).
4.21	Registration Rights Agreement dated as of January 28, 2016 among Plains All American Pipeline, L.P. and the Purchasers named therein (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed February 2, 2016).
10.1	Voting Agreement, dated as of July 11, 2016, by and among Plains All American Pipeline, L.P., Plains GP Holdings, L.P. and the shareholders named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed July 14, 2016).
12.1	Computation of Ratio of Earnings to Fixed Charges.
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.

Table of Contents

101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

Filed herewith.

Furnished herewith.

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