PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
August 07, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2015

OR

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

Commission File Number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

Delaware	76-0582150
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

333 Clay Street, Suite 1600, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 646-4100

(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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	Accelerated filer
Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company

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

As of July 31, 2015, there were 397,680,214 Common Units outstanding.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1.UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(in

(in millions, except unit data)

	June 30, 2015 (unaudited)	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 28	$ 403
Trade accounts receivable and other receivables, net	2,688	2,615
Inventory	941	891
Other current assets	287	270
Total current assets	3,944	4,179
PROPERTY AND EQUIPMENT	15,077	14,178
Accumulated depreciation	(2,049)	(1,906)
Property and equipment, net	13,028	12,272
OTHER ASSETS		
Goodwill	2,442	2,465
Investments in unconsolidated entities	1,841	1,735
Linefill and base gas	976	930
Long-term inventory	159	186
Other long-term assets, net	494	489
Total assets	$ 22,884	$ 22,256
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,117	$ 2,986

Short-term debt	915	1,287
Other current liabilities	442	482
Total current liabilities	4,474	4,755
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $16 and $18, respectively	8,759	8,757
Other long-term debt	378	5
Other long-term liabilities and deferred credits	568	548
Total long-term liabilities	9,705	9,310
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
PARTNERS' CAPITAL		
Common unitholders (397,680,214 and 375,107,793 units outstanding, respectively)	8,280	7,793
General partner	367	340
Total partners' capital excluding noncontrolling interests	8,647	8,133
Noncontrolling interests	58	58
Total partners' capital	8,705	8,191
Total liabilities and partners' capital	$ 22,884	$ 22,256

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$ 6,346	$ 10,856	$ 11,978	$ 22,201
Transportation segment revenues	180	195	366	376
Facilities segment revenues	137	144	261	301
Total revenues	6,663	11,195	12,605	22,878
COSTS AND EXPENSES				
Purchases and related costs	5,848	10,280	10,890	20,950
Field operating costs	417	360	763	696
General and administrative expenses	79	90	157	179
Depreciation and amortization	110	100	217	196
Total costs and expenses	6,454	10,830	12,027	22,021
OPERATING INCOME	209	365	578	857
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	52	23	89	44
Interest expense (net of capitalized interest of $13, $10, $27 and $22, respectively)	(105)	(82)	(207)	(161)
Other income/(expense), net	1	4	(3)	2
INCOME BEFORE TAX	157	310	457	742
Current income tax expense	(19)	(16)	(61)	(52)
Deferred income tax benefit/(expense)	(14)	(6)	12	(18)
NET INCOME	124	288	408	672
Net income attributable to noncontrolling interests	—	(1)	(1)	(1)
NET INCOME ATTRIBUTABLE TO PAA	$ 124	$ 287	$ 407	$ 671
NET INCOME ATTRIBUTABLE TO PAA:				
LIMITED PARTNERS	$ (22)	$ 166	$ 116	$ 435
GENERAL PARTNER	$ 146	$ 121	$ 291	$ 236
	$ (0.06)	$ 0.45	$ 0.29	$ 1.19

BASIC NET INCOME/(LOSS) PER LIMITED PARTNER UNIT				
DILUTED NET INCOME/(LOSS) PER LIMITED PARTNER UNIT	$ (0.06)	$ 0.45	$ 0.29	$ 1.18
BASIC WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING	397	365	390	363
DILUTED WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING	400	367	393	365

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)

(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(unaudited)		(unaudited)	
Net income	$ 124	$ 288	$ 408	$ 672
Other comprehensive income/(loss)	170	91	(206)	(45)
Comprehensive income	294	379	202	627
Comprehensive income attributable to noncontrolling interests	—	(1)	(1)	(1)
Comprehensive income attributable to PAA	$ 294	$ 378	$ 201	$ 626

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, 2014	$ (159)	$ (308)	$ (467)
Reclassification adjustments	19	—	19
Deferred gain on cash flow hedges, net of tax	20	—	20
Currency translation adjustments	—	(245)	(245)
Total period activity	39	(245)	(206)

Balance at June 30, 2015	$ (120)	$ (553)	$ (673)

	Derivative Instruments	Translation Adjustments	Total
	(unaudited)		
Balance at December 31, 2013	$ (77)	$ (20)	$ (97)
Reclassification adjustments	10	—	10
Deferred loss on cash flow hedges, net of tax	(51)	—	(51)
Currency translation adjustments	—	(4)	(4)
Total period activity	(41)	(4)	(45)
Balance at June 30, 2014	$ (118)	$ (24)	$ (142)

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Six Months Ended June 30,	
	2015	2014
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 408	$ 672
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	217	196
Equity-indexed compensation expense	36	68
Inventory valuation adjustments	24	37
Deferred income tax (benefit)/expense	(12)	18
Gain on sales of linefill and base gas	—	(8)
Gain on foreign currency revaluation	(26)	(5)
Settlement of terminated interest rate hedging instruments	(29)	(7)
Equity earnings in unconsolidated entities	(89)	(44)
Distributions from unconsolidated entities	102	51
Other	(11)	5
Changes in assets and liabilities, net of acquisitions	40	(20)
Net cash provided by operating activities	660	963
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(64)	(2)
Additions to property, equipment and other	(1,031)	(918)
Investment in unconsolidated entities	(119)	(67)
Cash received for sales of linefill and base gas	—	23
Cash paid for purchases of linefill and base gas	(125)	(140)
Proceeds from sales of assets	2	3
Other investing activities	(6)	—
Net cash used in investing activities	(1,343)	(1,101)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) under commercial paper program (Note 6)	151	(344)
Proceeds from the issuance of senior notes (Note 6)	—	698
Repayments of senior notes (Note 6)	(149)	—
Net proceeds from the issuance of common units (Note 7)	1,099	444
Contributions from general partner	23	9
Distributions paid to common unitholders (Note 7)	(526)	(450)
Distributions paid to general partner (Note 7)	(284)	(222)

Distributions paid to noncontrolling interests	(1)	(1)
Other financing activities	(4)	(10)
Net cash provided by financing activities	309	124
Effect of translation adjustment on cash	(1)	—
Net decrease in cash and cash equivalents	(375)	(14)
Cash and cash equivalents, beginning of period	403	41
Cash and cash equivalents, end of period	$ 28	$ 27
Cash paid for:		
Interest, net of amounts capitalized	$ 190	$ 161
Income taxes, net of amounts refunded	$ 30	$ 104

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL

(in millions)

	Common Units		General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Units	Amount				
	(unaudited)					
Balance at December 31, 2014	375.1	$ 7,793	$ 340	$ 8,133	$ 58	$ 8,191
Net income	—	116	291	407	1	408
Distributions	—	(526)	(284)	(810)	(1)	(811)
Issuance of common units	22.1	1,099	22	1,121	—	1,121
Issuance of common units under LTIP	0.5	—	1	1	—	1
Settlement of employee income tax withholding obligations under LTIP	—	(13)	—	(13)	—	(13)
Equity-indexed compensation expense	—	16	1	17	—	17
Distribution equivalent right payments	—	(3)	—	(3)	—	(3)
Other comprehensive loss	—	(202)	(4)	(206)	—	(206)
Balance at June 30, 2015	397.7	$ 8,280	$ 367	$ 8,647	$ 58	$ 8,705

	Common Units		General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Units	Amount				
	(unaudited)					
Balance at December 31, 2013	359.1	$ 7,349	$ 295	$ 7,644	$ 59	$ 7,703
Net income	—	435	236	671	1	672
Distributions	—	(450)	(222)	(672)	(1)	(673)
Issuance of common units	8.1	444	9	453	—	453
Issuance of common units under LTIP	0.6	1	1	2	—	2
Settlement of employee income tax withholding obligations under LTIP	—	(19)	—	(19)	—	(19)
Equity-indexed compensation expense	—	19	4	23	—	23
	—	(3)	—	(3)	—	(3)

Distribution equivalent right payments											
Other comprehensive loss	—		(44)		(1)		(45)		—		(45)
Other	—		(1)		—		(1)		—		(1)
Balance at June 30, 2014	367.8	$	7,731	$	322	$	8,053	$	59	$	8,112

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1—Organization and Basis of Consolidation and Presentation

Organization

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

We own and operate midstream energy infrastructure and provide logistics services for crude oil, natural gas liquids ("NGL"), natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics. See Note 11 for further discussion of our operating segments.

Our 2% general partner interest is held by PAA GP LLC, 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 LLC, 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, 2015, owned an approximate 37% limited partner interest in AAP.

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 LLC, AAP and GP LLC.

Definitions

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

AOCI	=	Accumulated other comprehensive income/(loss)
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
DERs	=	Distribution equivalent rights
EPA	=	United States Environmental Protection Agency
FASB	=	Financial Accounting Standards Board
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	Intercontinental Exchange
LIBOR	=	London Interbank Offered Rate
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MLP	=	Master limited partnership
NGL	=	Natural gas liquids, including ethane, propane and butane
NYMEX	=	New York Mercantile Exchange
Oxy	=	Occidental Petroleum Corporation or its subsidiaries
PLA	=	Pipeline loss allowance
SEC	=	United States Securities and Exchange Commission
USD	=	United States dollar
WTI	=	West Texas Intermediate

Basis of Consolidation and Presentation

The accompanying unaudited condensed consolidated interim financial statements and related notes thereto should be read in conjunction with our 2014 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. These reclassifications do not affect net income attributable to PAA. The condensed consolidated balance sheet data as of December 31, 2014 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, 2015 should not be taken as indicative of results to be expected for the entire year.

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

Note 2—Recent Accounting Pronouncements

In April 2015, the FASB issued guidance to simplify the presentation of debt issuance costs in entities' financial statements. Under this revised guidance, an entity will present such costs as a direct reduction from the related debt liability (rather than as an asset under current guidance). Additionally, amortization of the debt issuance costs will be reported as interest expense. This guidance will become effective for interim and annual periods beginning after December 15, 2015 and will be adopted retrospectively to all prior periods. Early adoption is permitted for financial statements that have not been previously issued. We expect to adopt this guidance on January 1, 2016, and we are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations and cash flows.

In February 2015, the FASB issued guidance that revises the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. All legal entities are subject to reevaluation under the revised consolidation model. Among other things, this guidance (i) modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities, (ii) eliminates the presumption that a general partner should consolidate a limited partnership and (iii) affects the consolidation analysis of reporting entities that are involved with variable interest entities, particularly those that have fee arrangements and related party relationships. This guidance will become effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted, including adoption in an interim period. We expect to adopt this guidance on January 1, 2016, and we are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations and cash flows.

In January 2015, as part of its initiative to reduce complexity in accounting standards, the FASB issued guidance to eliminate the concept of extraordinary items from GAAP. This guidance will become effective for interim and annual periods beginning after December 15, 2015. We expect to adopt this guidance on January 1, 2016. We do not believe our adoption will have a material impact on our financial position, results of operations or cash flows.

In May 2014, the FASB issued guidance regarding the recognition of revenue from contracts with customers with the underlying principle that an entity will recognize revenue to reflect amounts expected to be received in exchange for the provision of goods and services to customers upon the transfer of those goods or services. The guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. This guidance can be adopted either with a full retrospective approach or a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. In July 2015, the FASB voted to approve a one-year deferral of the effective date of this standard, with final guidance expected to be issued by the end of the third quarter of 2015. This deferral would make the guidance effective for interim and annual periods beginning after December 15, 2017. Therefore, we currently expect to adopt this guidance on January 1, 2018, and we are evaluating which transition

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approach to apply and the effect that adopting this guidance will have on our financial position, results of operations and cash flows.

In April 2014, the FASB issued guidance that modifies the criteria under which assets to be disposed of are evaluated to determine if such assets qualify as a discontinued operation and requires new disclosures for both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. This guidance is effective prospectively for annual and interim reporting periods beginning after December 15, 2014. We adopted this guidance on January 1, 2015. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

Note 3—Net Income Per Limited Partner Unit

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

Diluted net income per limited partner unit is computed based on the weighted average number of limited partner units plus the effect of dilutive potential limited partner units outstanding during the period using the two-class method. 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 limited partner unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. See Note 16 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for a complete discussion of our LTIP awards including specific discussion regarding DERs.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Basic Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 124	$ 287	$ 407	$ 671
Less: General partner's incentive distribution (1)	(146)	(117)	(289)	(227)
Less: General partner 2% ownership (1)	—	(4)	(2)	(9)
Net income/(loss) attributable to limited partners	(22)	166	116	435
Less: Undistributed earnings allocated and distributions to participating securities (1)	(1)	(1)	(3)	(3)
Net income/(loss) attributable to limited partners in accordance with application of the two-class method for MLPs	$ (23)	$ 165	$ 113	$ 432
Basic weighted average limited partner units outstanding	397	365	390	363
Basic net income/(loss) per limited partner unit	$ (0.06)	$ 0.45	$ 0.29	$ 1.19
Diluted Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 124	$ 287	$ 407	$ 671
Less: General partner's incentive distribution (1)	(146)	(117)	(289)	(227)
Less: General partner 2% ownership (1)	—	(4)	(2)	(9)
Net income/(loss) attributable to limited partners	(22)	166	116	435
Less: Undistributed earnings allocated and distributions to participating securities (1)	(1)	(1)	(3)	(3)
Net income/(loss) attributable to limited partners in accordance with application of the two-class method for MLPs	$ (23)	$ 165	$ 113	$ 432
Basic weighted average limited partner units outstanding	397	365	390	363
Effect of dilutive securities: Weighted average LTIP units	3	2	3	2
Diluted weighted average limited partner units outstanding	400	367	393	365
Diluted net income/(loss) per limited partner unit	$ (0.06)	$ 0.45	$ 0.29	$ 1.18

(1) We calculate net income attributable to limited partners 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, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

Pursuant to the terms of our partnership agreement, the general partner's incentive distribution is limited to a percentage of available cash, which, as defined in the 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 limited partner 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/(loss) per limited partner unit as reflected in the table above would not have been impacted, as we did not have undistributed earnings for any of the periods presented.

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Note 4—Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL and natural gas. These purchasers include, but are not limited to, refiners, producers, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. The majority of our accounts receivable relate to our crude oil supply and logistics activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

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, 2015 and December 31, 2014, we had received $115 million and $180 million, respectively, of advance cash payments from third parties to mitigate credit risk. We also received $77 million and $198 million, as of June 30, 2015 and December 31, 2014, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. The decrease in standby letters of credit and advance cash payments from third parties as of June 30, 2015 compared to December 31, 2014 is largely due to a decrease in exposure to various customers requiring letters of credit. 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, 2015 and December 31, 2014, 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 as of both June 30, 2015 and December 31, 2014. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

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

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

	June 30, 2015				December 31, 2014			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)
Inventory								
Crude oil	12,916	barrels	$ 649	$ 50.25	6,465	barrels	$ 304	$ 47.02
NGL	12,931	barrels	213	$ 16.47	13,553	barrels	454	$ 33.50
Natural gas	16,342	Mcf	45	$ 2.75	32,317	Mcf	102	$ 3.16
Other	N/A		34	N/A	N/A		31	N/A
Inventory subtotal			941				891	
Linefill and base gas								
Crude oil	13,195	barrels	790	$ 59.87	11,810	barrels	744	$ 63.00
NGL	1,348	barrels	48	$ 35.61	1,212	barrels	52	$ 42.90
Natural gas	29,812	Mcf	138	$ 4.63	28,612	Mcf	134	$ 4.68
Linefill and base gas subtotal			976				930	
Long-term inventory								
Crude oil	2,420	barrels	134	$ 55.37	2,582	barrels	136	$ 52.67
NGL	1,652	barrels	25	$ 15.13	1,681	barrels	50	$ 29.74
Long-term inventory subtotal			159				186	
Total			$ 2,076				$ 2,007	

(1) Price per unit of measure is comprised of a weighted average associated with various grades, qualities and locations. Accordingly, these prices may not coincide with any published benchmarks for such products.

At the end of each reporting period, we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. Any resulting adjustments are a component of "Purchases and related costs" on our accompanying Condensed Consolidated Statements of Operations. We recorded a charge of $24 million during the six months ended June 30, 2015, which primarily related to the writedown of our NGL inventory due to declines in prices during the first quarter of 2015. The loss was substantially offset by a portion of the derivative mark-to-market gain that was recognized in the fourth quarter of 2014. See Note 8 for discussion of our derivative and risk management activities. During the six months ended June 30, 2014, we recorded a charge of $37 million related to the writedown of our natural gas inventory that was purchased in conjunction with managing natural gas storage deliverability requirements during the extended period of severe cold weather in the first quarter of 2014.

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Note 6—Debt

Debt consisted of the following as of the dates indicated (in millions):

	June 30, 2015	December 31, 2014
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 0.49% and 0.46%, respectively (1)	$ 512	$ 734
Senior notes:		
5.25% senior notes due June 2015	—	150
3.95% senior notes due September 2015	400	400
Other	3	3
Total short-term debt	915	1,287
LONG-TERM DEBT		
Senior notes, net of unamortized discount of $16 and $18, respectively	8,759	8,757
Commercial paper notes, bearing a weighted-average interest rate of 0.49% (2)	373	—
Other	5	5
Total long-term debt	9,137	8,762
Total debt (3)	$ 10,052	$ 10,049

(1) We classified these commercial paper notes as short-term at June 30, 2015 and December 31, 2014 as these notes 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) We have the ability and intent to refinance these commercial paper notes on a long-term basis; therefore, we have classified such notes as long-term at June 30, 2015.

(3) Our fixed-rate senior notes (including current maturities) had a face value of approximately $9.2 billion and $9.3 billion as of June 30, 2015 and December 31, 2014, respectively. We estimated the aggregate fair value of these notes as of June 30, 2015 and December 31, 2014 to be approximately $9.4 billion and $9.9 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.

Credit Facilities

Senior unsecured 364-day revolving credit facility. In January 2015, we entered into a 364-day senior unsecured credit agreement with a borrowing capacity of $1.0 billion. Borrowings will accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, as defined in the agreement, in each case plus a margin based on our credit rating at the applicable time.

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Borrowings and Repayments

Total borrowings under our credit agreements and commercial paper program for the six months ended June 30, 2015 and 2014 were approximately $17.9 billion and $34.6 billion, respectively. Total repayments under our credit agreements and commercial paper program were approximately $17.7 billion and $34.9 billion for the six months ended June 30, 2015 and 2014, 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, 2015 and December 31, 2014, we had outstanding letters of credit of $63 million and $87 million, respectively.

Senior Notes Repayments

In June 2015, we repaid our $150 million, 5.25% senior notes. We utilized cash on hand and available capacity under our commercial paper program to repay these notes.

Note 7—Partners' Capital and Distributions

Distributions

The following table details the distributions paid during or pertaining to the first six months of 2015, net of reductions to the general partner's incentive distributions (in millions, except per unit data):

			Distributions Paid				Distributions
			Limited	General Partner			per limited
Date Declared	Distribution Date		Partners	2%	Incentive	Total	partner unit
July 7, 2015	August 14, 2015	(1)	$ 276	$ 6	$ 146	$ 428	$ 0.6950
April 7, 2015	May 15, 2015		$ 272	$ 6	$ 142	$ 420	$ 0.6850
January 8, 2015	February 13, 2015		$ 254	$ 5	$ 131	$ 390	$ 0.6750

(1) Payable to unitholders of record at the close of business on July 31, 2015 for the period April 1, 2015 through June 30, 2015.

PAA Equity Offerings

Continuous Offering Program. During the six months ended June 30, 2015, we issued an aggregate of approximately 1.1 million common units under our continuous offering program, generating proceeds of $59 million, including our general partner's proportionate capital contribution of $1 million, net of $1 million of commissions to our sales agents.

Underwritten Offering. In March 2015, we completed an underwritten public offering of 21.0 million common units, generating proceeds of approximately $1.1 billion, including our general partner's proportionate capital contribution of $21 million, net of costs associated with the offering.

Noncontrolling Interests in Subsidiaries

As of June 30, 2015, noncontrolling interests in our subsidiaries consisted of a 25% interest in SLC Pipeline LLC.

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Note 8—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 on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items.

Commodity Price Risk Hedging

Our core business activities involve certain commodity price-related risks that we manage in various ways, including through the use of derivative instruments. Our policy is to (i) only purchase inventory for which we have a market, (ii) structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities can be divided into the following general categories:

Commodity Purchases and Sales — In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of June 30, 2015, net derivative positions related to these activities included:

- An average of 151,600 barrels per day net long position (total of 4.7 million barrels) associated with our crude oil purchases, which was unwound ratably during July 2015 to match monthly average pricing.

- A net short time spread position averaging 17,800 barrels per day (total of 7.6 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through October 2016.

· An average of 35,800 barrels per day (total of 5.5 million barrels) of crude oil grade spread positions through December 2015. These derivatives allow us to lock in grade basis differentials.

· A net short position of 13.9 Bcf through April 2016 related to anticipated sales of natural gas inventory and base gas requirements.

· A net short position of 15.3 million barrels through June 2017 related to anticipated purchases and sales of our crude oil, NGL and refined products inventory.

Storage Capacity Utilization — We own a significant amount of crude oil, NGL and refined products storage capacity other than that used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk in a backwardated market structure. As of June 30, 2015, we used derivatives to manage the risk of not utilizing approximately 0.8 million barrels of storage capacity through January 2016. These positions involve no outright price exposure, but instead enable us to profitably use the capacity to store hedged crude oil.

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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, 2015, we had a long natural gas position of 15.2 Bcf through December 2016, a short propane position of 2.9 million barrels through December 2016, a short butane position of 0.9 million barrels through December 2016 and a short WTI position of 0.3 million barrels through December 2016. In addition, we had a long power position of 0.5 million megawatt hours, which hedges a portion of our power supply requirements at our natural gas processing and fractionation plants through December 2018.

To the extent they qualify and we decide to make the election, all of our commodity derivatives for which we elect hedge accounting are designated as cash flow hedges. 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 purchase and sale agreements 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 primarily of interest rate swaps and treasury locks. As of June 30, 2015, AOCI includes deferred losses of $109 million that relate to open and terminated interest rate derivatives that were designated as cash flow hedges. The terminated interest rate derivatives were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the terms of the hedged debt instruments.

We have entered into forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted interest payments through 2049. The following table summarizes the terms of our forward starting interest rate swaps as of June 30, 2015 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
	7 forward starting	$ 250	9/15/2015	3.02 %	

Anticipated interest payments	swaps (30-year)					Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/15/2016	3.06	%	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 2015, we terminated ten forward starting swaps. These swaps had an aggregate notional amount of $250 million and an average fixed rate of 3.60%. We made a cash payment of approximately $31 million in connection with the termination of these swaps.

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.

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As of June 30, 2015, our outstanding foreign currency derivatives include derivatives we use to (i) hedge currency exchange risk associated with USD-denominated commodity purchases and sales in Canada and (ii) hedge currency exchange risk created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

The following table summarizes our open forward exchange contracts as of June 30, 2015 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD		
Forward exchange contracts that exchange CAD for USD:						
	2015	$ 208	$ 260	$ 1.00	-	$ 1.25
	2016	30	38	$ 1.00	-	$ 1.25
		$ 238	$ 298			
Forward exchange contracts that exchange USD for CAD:						
	2015	$ 253	$ 315	$ 1.00	-	$ 1.24
	2016	30	37	$ 1.00	-	$ 1.22
		$ 283	$ 352			

Summary of Financial Impact

We record all open derivatives on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify as cash flow hedges, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions are recognized in earnings. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items are recognized in earnings each period. Cash settlements associated with our derivative activities are classified within the same category as the related hedged item in our Condensed Consolidated Statements of Cash Flows.

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

	Three Months Ended June 30, 2015			
	Derivatives in Hedging Relationships			
Location of Gain/(Loss)	Gain/(Loss) Reclassified from AOCI into Income (1) (2)	Other Gain/(Loss) Recognized in Income (3)	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives				
Supply and Logistics segment revenues	$ (19)	$ —	$ 44	$ 25
Transportation segment revenues	—	—	2	2
Field operating costs	—	—	2	2
Interest Rate Derivatives				
Interest expense	(6)	2	—	(4)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (25)	$ 2	$ 48	$ 25

	Three Months Ended June 30, 2014			
	Derivatives in Hedging Relationships			
Location of Gain/(Loss)	Gain/(Loss) Reclassified from AOCI into Income (1)	Other Gain/(Loss) Recognized in Income (3)	Derivatives Not Designated as a Hedge	Total

	(2)			
Commodity Derivatives				
Supply and Logistics segment revenues	$ 12	$ —	$ —	$ 12
Interest Rate Derivatives				
Interest expense	(1)	—	—	(1)
Foreign Currency Derivatives				
Supply and Logistics segment revenues	—	—	9	9
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 11	$ —	$ 9	$ 20

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	Six Months Ended June 30, 2015			
	Derivatives in Hedging Relationships			
Location of Gain/(Loss)	Gain/(Loss) Reclassified from AOCI into Income (1) (2)	Other Gain/(Loss) Recognized in Income (3)	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives				
Supply and Logistics segment revenues	$ (12)	$ —	$ 10	$ (2)
Transportation segment revenues	—	—	4	4
Field operating costs	—	—	(2)	(2)
Interest Rate Derivatives				
Interest expense	(7)	2	—	(5)
Foreign Currency Derivatives				
Supply and Logistics segment revenues	—	—	(17)	(17)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (19)	$ 2	$ (5)	$ (22)

	Six Months Ended June 30, 2014			
	Derivatives in Hedging Relationships			
Location of Gain/(Loss)	Gain/(Loss) Reclassified from AOCI into Income (1) (2)	Other Gain/(Loss) Recognized in Income (3)	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives				

Supply and Logistics segment revenues	$ (8)	$ —	$ —	$ (8)
Field operating costs	—	—	(1)	(1)
Interest Rate Derivatives				
Interest expense	(2)	—	—	(2)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (10)	$ —	$ (1)	$ (11)

(1) Represents gains/(losses) on cash flow hedges reclassified from AOCI to income during the period.

(2) During the three and six months ended June 30, 2015 we reclassified a loss of approximately $4 million from AOCI to Interest expense as a result of anticipated hedged transactions that are probable of not occurring. All of our anticipated hedged transactions were deemed probable of occurring during the three and six months ended June 30, 2014.

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(3) Amounts represent ineffective portion of cash flow hedges.

The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheets on a gross basis as of June 30, 2015 (in millions):

	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 11	Other current liabilities	$ (1)
	Other long-term liabilities and deferred credits	2		
Interest rate derivatives	Other current assets	1	Other current liabilities	(6)
	Other long-term assets, net	16	Other long-term liabilities and deferred credits	(2)
Total derivatives designated as hedging instruments		$ 30		$ (9)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 139	Other current assets	$ (59)
	Other long-term assets, net	14	Other long-term assets, net	(1)
	Other current liabilities	1	Other current liabilities	(17)
			Other long-term liabilities and deferred credits	(4)
Foreign currency derivatives			Other current liabilities	(2)
Total derivatives not designated as hedging		$ 154		$ (83)

instruments		
Total derivatives	$ 184	$ (92)

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The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheets on a gross basis as of December 31, 2014 (in millions):

	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 23	Other current assets	$ (12)
	Other long-term assets, net	8	Other long-term assets, net	(1)
Interest rate derivatives			Other current liabilities	(44)
			Other long-term liabilities and deferred credits	(26)
Total derivatives designated as hedging instruments		$ 31		$ (83)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 439	Other current assets	$ (246)
	Other long-term assets, net	23	Other long-term assets, net	(3)
			Other current liabilities	(35)
			Other long-term liabilities and deferred credits	(5)
Foreign currency derivatives			Other current liabilities	(12)
Total derivatives not designated as hedging instruments		$ 462		$ (301)
Total derivatives		$ 493		$ (384)

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 our 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, 2015, we had a net broker payable of $46 million (consisting of initial margin of $49 million reduced by $95 million of variation margin that had been returned to us). As of December 31, 2014, we had a net broker payable of $133 million (consisting of initial margin of $126 million reduced by $259 million of variation margin that had been returned to us).

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The following table presents information about derivatives and financial assets and liabilities that are subject to offsetting, including enforceable master netting arrangements as of the dates indicated (in millions):

	June 30, 2015		December 31, 2014	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 184	$ (92)	$ 493	$ (384)
Netting adjustment	(63)	63	(262)	262
Cash collateral paid/(received)	(46)	—	(133)	—
Net position - asset/(liability)	$ 75	$ (29)	$ 98	$ (122)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 46	$ —	$ 71	$ —
Other long-term assets, net	29	—	27	—
Other current liabilities	—	(25)	—	(91)
Other long-term liabilities and deferred credits	—	(4)	—	(31)
	$ 75	$ (29)	$ 98	$ (122)

As of June 30, 2015, there was a net loss of $120 million deferred in AOCI including tax effects. 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, 2015, we expect to reclassify a net gain of $4 million to earnings in the next twelve months. The remaining deferred loss of $124 million is expected to be reclassified to earnings through 2049. A portion of these amounts are based on market prices as of June 30, 2015; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The net deferred gain/(loss), including tax effects, recognized in AOCI for derivatives for the periods indicated was as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014

Commodity derivatives, net	$ (28)	$ —	$ (25)	$ (12)
Interest rate derivatives, net	120	(19)	45	(39)
Total	$ 92	$ (19)	$ 20	$ (51)

At June 30, 2015 and December 31, 2014, 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.

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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 as of the dates indicated (in millions):

	Fair Value as of June 30, 2015				Fair Value as of December 31, 2014			
Recurring Fair Value Measures (1)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	$ (18)	$ 94	$ 9	$ 85	$ (85)	$ 261	$ 15	$ 191
Interest rate derivatives	—	9	—	9	—	(70)	—	(70)
Foreign currency derivatives	—	(2)	—	(2)	—	(12)	—	(12)
Total net derivative asset/(liability)	$ (18)	$ 101	$ 9	$ 92	$ (85)	$ 179	$ 15	$ 109

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

Level 1

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

Level 2

Level 2 of the fair value hierarchy includes exchange-cleared commodity derivatives and over-the-counter commodity, interest rate and foreign currency derivatives that are traded in active markets. In addition, it includes certain physical commodity contracts. The fair value of these derivatives is based on broker price quotations which are corroborated with market observable inputs.

Level 3

Level 3 of the fair value hierarchy includes certain physical commodity contracts. 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 Level 3 derivatives. We report unrealized gains and losses associated with Level 3 commodity derivatives in our Condensed Consolidated Statements of Operations as Supply and Logistics segment revenues.

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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 for the periods indicated (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Beginning Balance	$ 5	$ 1	$ 15	$ (3)
Gains/(losses) for the period included in earnings	1	—	1	—
Settlements	(1)	—	(13)	3
Derivatives entered into during the period	4	—	6	1
Ending Balance	$ 9	$ 1	$ 9	$ 1
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	$ 5	$ 1	$ 6	$ 1

Note 9—Equity-Indexed Compensation Plans

We refer to the PAA LTIPs and AAP Management Units collectively as our “equity-indexed compensation plans.” For additional discussion of our equity-indexed compensation plans and awards, see Note 16 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K.

PAA LTIP Awards

Activity for LTIP awards under our equity-indexed compensation plans denominated in PAA units is summarized in the following table (units in millions):

	Units (1)	Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2014	7.3	$ 41.45
Granted	1.1	$ 39.98
Vested (2)	(1.8)	$ 25.96
Cancelled or forfeited	(0.1)	$ 43.26
Outstanding at June 30, 2015	6.5	$ 45.47

(1) Amounts do not include AAP Management Units.

(2) Approximately 0.5 million PAA common units were issued, net of tax withholding of 0.2 million units, during the six months ended June 30, 2015 in connection with the settlement of vested awards. The remaining PAA awards that vested during the six months ended June 30, 2015 of approximately 1.1 million units were settled in cash.

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AAP Management Units

Activity for AAP Management Units is summarized in the following table (in millions):

	Reserved for Future Grants	Outstanding	Outstanding Units Earned	Grant Date Fair Value Of Outstanding AAP Management Units (1)
Balance at December 31, 2014	3.0	49.1	47.8	$ 64
Earned	N/A	N/A	0.4	N/A
Balance at June 30, 2015	3.0	49.1	48.2	$ 64

(1) Of the $64 million grant date fair value, $57 million had been recognized through June 30, 2015 on a cumulative basis. Of this amount, $1 million was recognized as expense during the six months ended June 30, 2015.

Other Consolidated Equity-Indexed Compensation Plan Information

The table below summarizes the expense recognized and the value of vested LTIP awards (settled both in common units and cash) under our equity-indexed compensation plans and includes both liability-classified and equity-classified awards for the periods indicated (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Equity-indexed compensation expense	$ 17	$ 34	$ 36	$ 68
LTIP unit-settled vestings	$ 35	$ 44	$ 35	$ 51
LTIP cash-settled vestings	$ 55	$ 51	$ 55	$ 52
DER cash payments	$ 2	$ 2	$ 4	$ 4

Note 10—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.

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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 and storage 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.

At June 30, 2015, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident, as discussed further below) totaled $297 million, of which $197 million was classified as short-term and $100 million was classified as long-term. At December 31, 2014, our estimated undiscounted reserve for environmental liabilities totaled $82 million, of which $13 million was classified as short-term and $69 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, 2015 and December 31, 2014, we had recorded receivables totaling $200 million and $8 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, which are predominantly reflected in “Trade accounts receivable and other receivables, 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 legal claims giving rise to additional liabilities. Therefore, although we believe that the reserve is adequate, costs incurred 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. During 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 and contamination monitoring continue, and the cause of the release is currently under investigation.

Although the precise volume of crude oil released in connection with this incident has not been determined, following the release, we developed and have periodically updated a "worst case" estimate of the amount of oil spilled, which represents what we believe to be the maximum volume of oil that could have been spilled based on relevant facts, data and information available at the time of such calculation. Our worst-case estimate has been developed primarily using information regarding (i) an estimate of the amount of oil that flowed into Line 901 during the period between the estimated time of release and the point when the pumps were shut down and (ii) an estimate of the volume of oil that drained out of the line due to the natural force of gravity based on the characteristics of the pipeline (i.e., length, elevation profile, diameter and location of the release point). Using this "drain-down" methodology, our worst case estimate of the volume of oil released totaled approximately 2,400 barrels. We believe that the “drain-down” methodology represents the most straight forward and accurate calculation of the potential worst case discharge.

In the second half of June we completed the process of emptying and purging Line 901, which resulted in the removal of approximately 26,500 barrels of crude oil from the line. This activity provided additional data to assess the reasonableness of our worst case estimate of 2,400 barrels based on the “drain-down” methodology. Based on a preliminary analysis, an alternative calculation using the purge data could be as much as 1,000 barrels higher than the worst-case estimate calculated using the drain-down methodology. However, the alternative calculation does not take into account certain factors that could account for a meaningful portion of the difference between the two calculations and this reconciliation process is ongoing. As part of our effort to reconcile these differences, we have retained an outside, third party consulting firm to review the materials and submit a report, but such study has not been completed. Accordingly, to date we have not finalized our calculation of the “worst case” estimate of the amount of oil released from Line 901, and such volume estimate may change as additional facts, data and information are analyzed during the course of the investigation of this incident. Any variance between the current and final estimate of the worst case discharge is not expected to impact our estimate of response, clean-up or remediation costs, but could impact our estimate of fines and penalties.

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. Set forth below is a brief summary of such actions and matters:

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 that has 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 (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 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 fully intend 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. No timeline has been established for the restart of Line 901. 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, there can be no assurance that such fines or penalties will not be imposed upon us, or that such civil or criminal charges will not be brought against us, in the future.

In late May, on behalf of the EPA, 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 expressed an interest in talking to several of our employees and consistent with the terms of our governing organizational documents, we are funding their defense costs, including the costs of separate counsel engaged to represent such individuals. In addition to the DOJ, the California Attorney General's Office and the District Attorney's Office for the County of Santa Barbara have also announced that they are investigating the Line 901 incident to determine whether any applicable state or local laws have been violated. While to date no civil or criminal charges have been brought against PAA or any of its affiliates, officers or employees by the DOJ, California Attorney General or Santa Barbara County District Attorney, and no fines or penalties have been imposed by such governmental agents, there can be no assurance that such fines or penalties will not be imposed upon us, or that such civil or criminal charges will not be brought against us, in the future.

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 as we receive them. In addition, we have also had six class action lawsuits filed against us, all of which have been filed in the United States District Court for the Central District of California. In general, these lawsuits have been brought by various plaintiffs 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 businesses that were allegedly impacted by the release.

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, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $257 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 does not include any lost revenue associated with the shutdown of Line 901 or 903. In addition, 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 clean up, remediation and monitoring services will be required, the number of personnel and equipment required at the site and the rates charged by the associated service and equipment providers, (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 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. 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. Our assumptions and estimates may turn out to be inaccurate and our total costs could turn out to be higher; accordingly, we can provide no assurance that we will not have to accrue additional costs in the future with respect to the Line 901 incident.

We have accrued such estimate of aggregate total costs to "Field operating costs" on our Condensed Consolidated Statement of Operations. As of June 30, 2015, we had a remaining undiscounted gross liability of $221 million related to this event, the majority of which is presented as a current liability in "Accounts payable and accrued liabilities" on our Condensed Consolidated Balance Sheets. 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. We therefore have recognized a receivable of $192 million as of June 30, 2015 for the portion of the release costs that we believe is probable of recovery from insurance, net of deductibles. A majority of this receivable has been recognized as a current asset in “Trade accounts receivable and other receivables, net” on our Condensed Consolidated Balance Sheets with the offset reducing “Field operating costs” on our Condensed Consolidated Statement of Operations. We currently expect that the clean-up and remediation efforts, excluding long-term site monitoring activities, will be substantially completed during 2015; 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. We are in the process of satisfying the requirements of the corrective action order. 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. 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. In this lawsuit, the plaintiff seeks unspecified money damages and other remedies on behalf of itself and other unspecified similarly situated claimants. We estimate that the aggregate total costs associated with this release will be less than $10 million.

Cushing Tank Cathodic Protection. On May 22, 2015, PHMSA issued a Final Order relating to an April 2013 Notice of Probable Violation and Proposed Compliance Order alleging that we did not maintain adequate cathodic protection for certain tanks at our Cushing Terminal. In its 2013 Notice of Probable Violation, PHMSA maintained that the proprietary cathodic protection system utilized by us for certain of our storage tanks at our Cushing, Oklahoma facility was not contemplated by applicable regulations. In response to the notice, we provided extensive documentation and supporting information regarding the effectiveness of the technology we were utilizing, including past communications with PHMSA regarding the topic. At a hearing in August 2013 we gave a formal presentation on the technology, provided empirical data confirming its effectiveness and also had a third party corrosion expert witness speak to the effectiveness of the technology. Almost two years later, PHMSA issued the Final Order and Compliance Order dated May 22, 2015 ruling against our position, assessing a penalty of $102,900 and specifying certain corrective actions to be completed by us. We chose not to further contest this matter and paid the penalty on June 5, 2015. On July 14, 2015, we submitted to PHMSA a Remediation Plan and schedule to satisfy the conditions of the Compliance Order.

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.

National Energy Board Audit. In the third quarter of 2014, the National Energy Board ("NEB") of Canada notified PMC that various corrective actions from a 2010 audit had not been completed to the satisfaction of the NEB. The NEB initiated a process to assess PMC's approach to compliance with the NEB's Onshore Pipeline Regulations, which process resulted in the issuance by the NEB of an order on January 15, 2015 that imposed six conditions on PMC designed to enhance PMC's ability to operate its pipelines in a manner that protects the public and the environment. The conditions include the filing of certain safety critical tasks, controls and programs with the NEB, external audits of certain PMC programs and systems, and periodic update meetings with NEB staff regarding the status and progress of corrective actions. In early February 2015, the NEB imposed a penalty on PMC of $76,000 CAD related to these issues. It is possible that additional fines and penalties may be assessed against PMC in the future related to this matter.

Kemp River Pipeline Releases. During May and June 2013, two separate releases were discovered on our Kemp River pipeline in Northern Alberta, Canada that, in the aggregate, resulted in the release of approximately 700 barrels of condensate and light crude oil. Clean-up and remediation activities are being conducted in cooperation with the applicable regulatory agencies. Final investigation by the Alberta Energy Regulator is not complete. To date, no charges, fines or penalties have been assessed against PMC with respect to these releases; however, it is possible that fines or penalties may be assessed against PMC in the future. We estimate that the aggregate clean-up and remediation costs associated with these releases will be $15 million. Through June 30, 2015, we spent $9 million in connection with clean-up and remediation activities.

Bay Springs Pipeline Release. During February 2013, we experienced a crude oil release of approximately 120 barrels on a portion of one of our pipelines near Bay Springs, Mississippi. Most of the released crude oil was contained within our pipeline right of way, but some of the released crude oil entered a nearby waterway where it was contained with booms. The EPA has issued an administrative order requiring us to take various actions in response to the release,

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including remediation, reporting and other actions. We have satisfied the requirements of the administrative order; however, we may be subjected to a civil penalty. The aggregate cost to clean up and remediate the site was $6 million.

Note 11—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 for the periods indicated (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Three Months Ended June 30, 2015				
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
Three Months Ended June 30, 2014				
Revenues:				
External customers	$ 195	$ 144	$ 10,856	$ 11,195
Intersegment (1)	217	133	4	354
Total revenues of reportable segments	$ 412	$ 277	$ 10,860	$ 11,549
Equity earnings in unconsolidated entities	$ 23	$ —	$ —	$ 23
Segment profit (2) (3)	$ 221	$ 134	$ 133	$ 488
Maintenance capital	$ 42	$ 5	$ 1	$ 48

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	Transportation	Facilities	Supply and Logistics	Total
Six Months Ended June 30, 2015				
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
Six Months Ended June 30, 2014				
Revenues:				
External customers	$ 376	$ 301	$ 22,201	$ 22,878
Intersegment (1)	422	275	27	724
Total revenues of reportable segments	$ 798	$ 576	$ 22,228	$ 23,602
Equity earnings in unconsolidated entities	$ 44	$ —	$ —	$ 44
Segment profit (2) (3)	$ 427	$ 288	$ 382	$ 1,097
Maintenance capital	$ 76	$ 15	$ 4	$ 95

(1) Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market. For further discussion, see "Analysis of Operating Segments" under Item 7 of our 2014 Annual Report on Form 10-K.

(2) Supply and Logistics segment profit includes interest expense (related to hedged inventory purchases) of $2 million and $5 million for the three months ended June 30, 2015 and 2014, respectively, and $3 million and $7 million for the six months ended June 30, 2015 and 2014, 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,	
	2015	2014	2015	2014
Segment profit	$ 371	$ 488	$ 884	$ 1,097
Depreciation and amortization	(110)	(100)	(217)	(196)
Interest expense, net	(105)	(82)	(207)	(161)
Other income/(expense), net	1	4	(3)	2
Income before tax	157	310	457	742
Income tax expense	(33)	(22)	(49)	(70)
Net income	124	288	408	672
Net income attributable to noncontrolling interests	—	(1)	(1)	(1)
Net income attributable to PAA	$ 124	$ 287	$ 407	$ 671

Note 12—Related Party Transactions

See Note 15 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for a complete discussion of our related party transactions.

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Transactions with Oxy

As of June 30, 2015, 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, 2015 and 2014, 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. See detail below (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues	$ 382	$ 351	$ 558	$ 443
Purchases and related costs	$ 41	$ 209	$ 146	$ 468

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

	June 30, 2015	December 31, 2014
Trade accounts receivable and other receivables	$ 736	$ 489
Accounts payable	$ 588	$ 441

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical Consolidated Financial Statements and accompanying notes and Management's Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2014 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

For the six months ended June 30, 2015 and 2014, we recognized net income attributable to PAA of $407 million and $671 million, respectively. This decrease was primarily driven by less favorable results from our Supply and Logistics segment. In addition, our operating results for the 2015 period were impacted by costs and lost revenue associated with the Line 901 incident. See further discussion of our segment operating results in the following sections. Net income attributable to PAA for the first six months of 2015 was also impacted by higher depreciation and amortization expense and interest expense associated with our growing asset base and related financing activities.

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We invested approximately $1.2 billion in midstream infrastructure projects during the six months ended June 30, 2015, with a targeted expansion capital plan for the full year of 2015 of $2.2 billion. To fund a portion of such capital activities, we issued approximately 22.1 million common units for net proceeds of approximately $1.1 billion. In addition, we paid $810 million of cash distributions to our limited partners and general partner during the six months ended June 30, 2015, and we declared a quarterly distribution of $0.6950 per limited partner unit to be paid on August 14, 2015.

Acquisitions and Capital Projects

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

	Six Months Ended June 30,	
	2015	2014
Acquisition capital	$ 64	$ 2
Expansion capital (1)	1,188	1,012
Maintenance capital (1)	102	95
	$ 1,354	$ 1,109

(1) 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.

2015 Capital Projects

Our capital program is highlighted by a large number of small-to-medium sized projects spread across multiple geographic regions/resource plays. We believe the diversity of our program mitigates the impact of delays, cost overruns or adverse market developments with respect to a particular project or geographic region/resource play. The majority of our 2015 expansion capital program will be invested in our fee-based Transportation and Facilities segments. We expect that our investments will have minimal contributions to our 2015 results, but will provide growth for 2016 and beyond.

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The following table summarizes our notable projects in progress during 2015 and the forecasted expenditures for the year ending December 31, 2015 (in millions):

Projects	2015
Permian Basin Area Projects	$410
Fort Saskatchewan Facility Projects / NGL Line	310
Rail Terminal Projects (1)	275
Cactus Pipeline (2)	150
Saddlehorn Pipeline	140
Red River Pipeline (Cushing to Longview)	130
Eagle Ford JV Project	80
Cowboy Pipeline (Cheyenne to Carr)	50
St. James Terminal Expansions	50
Eagle Ford Area Projects	45
Diamond Pipeline	40
Cushing Terminal Expansions	40
Line 63 Reactivation	25
Other Projects	455
	$2,200
Potential Adjustments for Timing / Scope Refinement (3)	-$100 + $100
Total Projected Expansion Capital Expenditures	$2,100 - $2,300
Maintenance Capital Expenditures	$205 - $225

(1) Includes railcar purchases and projects located in or near St. James, LA, Kerrobert, Canada and Tampa, CO.

(2) Includes linefill costs associated with the project.

(3) 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 permits, regulatory approvals and weather.

Results of Operations

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 19 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on

Form 10-K for further discussion of how we evaluate segment profit.

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The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP for the periods indicated (in millions, except per unit data):

	Three Months Ended June 30,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
	2015	2014	$	%	2015	2014	$	%
Transportation segment profit	$ 186	$ 221	$ (35)	(16) %	$ 428	$ 427	$ 1	— %
Facilities segment profit	144	134	10	7 %	285	288	(3)	(1) %
Supply and Logistics segment profit	41	133	(92)	(69) %	171	382	(211)	(55) %
Total segment profit	371	488	(117)	(24) %	884	1,097	(213)	(19) %
Depreciation and amortization	(110)	(100)	(10)	(10) %	(217)	(196)	(21)	(11) %
Interest expense, net	(105)	(82)	(23)	(28) %	(207)	(161)	(46)	(29) %
Other income/(expense), net	1	4	(3)	(75) %	(3)	2	(5)	(250) %
Income tax expense	(33)	(22)	(11)	(50) %	(49)	(70)	21	30 %
Net income	124	288	(164)	(57) %	408	672	(264)	(39) %
Net income attributable to noncontrolling interests	—	(1)	1	100 %	(1)	(1)	—	— %
Net income attributable to PAA	$ 124	$ 287	$ (163)	(57) %	$ 407	$ 671	$ (264)	(39) %
Basic net income/(loss) per limited partner unit	$ (0.06)	$ 0.45	$ (0.51)	(113) %	$ 0.29	$ 1.19	$ (0.90)	(76) %
Diluted net income/(loss) per limited partner unit	$ (0.06)	$ 0.45	$ (0.51)	(113) %	$ 0.29	$ 1.18	$ (0.89)	(75) %
Basic weighted average limited partner units outstanding	397	365	32	9 %	390	363	27	7 %
Diluted weighted average limited partner units outstanding	400	367	33	9 %	393	365	28	8 %

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are 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 in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning 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 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), 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. We have defined all such items hereinafter as “Selected Items Impacting Comparability.” These additional financial measures are reconciled to the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Condensed Consolidated Financial Statements and footnotes.

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

	Three Months Ended June 30,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
	2015	2014	$	%	2015	2014	$	%
Net income	$ 124	$ 288	$ (164)	(57) %	$ 408	$ 672	$ (264)	(39) %
Add:								
Interest expense, net	105	82	23	28 %	207	161	46	29 %
Income tax expense	33	22	11	50 %	49	70	(21)	(30) %
Depreciation and amortization	110	100	10	10 %	217	196	21	11 %
EBITDA	$ 372	$ 492	$ (120)	(24) %	$ 881	$ 1,099	$ (218)	(20) %
Selected Items Impacting Comparability of EBITDA								
Gains/(losses) from derivative activities net of inventory valuation adjustments (1)	$ (60)	$ (14)	$ (46)	(329)%	$ (151)	$ 50	$ (201)	(402) %
Long-term inventory costing adjustments (2)	23	—	23	N/A	(15)	—	(15)	N/A
Equity-indexed compensation expense (3)	(11)	(17)	6	35 %	(22)	(36)	14	39 %
Net gain/(loss) on foreign currency revaluation (4)	(1)	11	(12)	(109)%	26	6	20	333 %
Line 901 incident (5)	(65)	—	(65)	N/A	(65)	—	(65)	N/A
Selected Items Impacting Comparability of EBITDA	$ (114)	$ (20)	$ (94)	(470)%	$ (227)	$ 20	$ (247)	(1,235)%
EBITDA	$ 372	$ 492	$ (120)	(24) %	$ 881	$ 1,099	$ (218)	(20) %
Selected Items Impacting Comparability of EBITDA	114	20	94	470 %	227	(20)	247	1,235 %
Adjusted EBITDA	$ 486	$ 512	$ (26)	(5) %	$ 1,108	$ 1,079	$ 29	3 %

Adjusted EBITDA	$ 486	$ 512	$ (26)	(5)	%	$ 1,108	$ 1,079	$ 29	3	%
Interest expense, net	(105)	(82)	(23)	(28)	%	(207)	(161)	(46)	(29)	%
Maintenance capital (6)	(52)	(48)	(4)	(8)	%	(102)	(95)	(7)	(7)	%
Current income tax expense	(19)	(16)	(3)	(19)	%	(61)	(52)	(9)	(17)	%
Equity earnings in unconsolidated entities, net of distributions	(3)	2	(5)	(250)	%	13	7	6	86	%
Distributions to noncontrolling interests (7)	(1)	(1)	—	—	%	(2)	(2)	—	—	%
Implied DCF (8)	$ 306	$ 367	$ (61)	(17)	%	$ 749	$ 776	$ (27)	(3)	%
Less: Distributions paid (7)	(428)	(360)				(848)	(704)			
DCF Excess/(Shortage) (9)	$ (122)	$ 7				$ (99)	$ 72			

(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

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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. See Note 8 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

(2) We carry approximately 4 million barrels of crude oil and NGL inventory that consists of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to Linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory that result from fluctuations in market prices and writedowns of such inventory that result from price declines as a selected item impacting comparability. See Note 5 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for a complete discussion of our long-term inventory.

(3) 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 earnings 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 earnings per unit calculation and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability. See Note 16 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for a comprehensive discussion regarding our equity-indexed compensation plans.

(4) During the three and six months ended June 30, 2015 and 2014, 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 selected items impacting comparability.

(5) Includes costs related to our Line 901 incident that occurred during May 2015, net of amounts we believe are probable of recovery from insurance recoveries. See Note 10 to our Condensed Consolidated Financial Statements for additional information.

(6) 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.

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

(8) Including costs of $65 million related to our Line 901 incident that occurred during May 2015, Implied DCF would have been $241 million and $684 million for the three and six months ended June 30, 2015, respectively. See Note 10 to our Condensed Consolidated Financial Statements for additional information regarding the Line 901incident.

(9) 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.

Analysis of Operating Segments

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.

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The following tables set forth our operating results from our Transportation segment for the periods indicated:

Operating Results (1) (in millions, except per barrel data)	Three Months Ended June 30, 2015	 2014	Favorable/ (Unfavorable) Variance $	 %	Six Months Ended June 30, 2015	 2014	Favorable/ (Unfavorable) Variance $	 %
Revenues								
Tariff activities	$ 361	$ 356	$ 5	1 %	$ 720	$ 691	$ 29	4 %
Trucking	41	56	(15)	(27)%	83	107	(24)	(22)%
Total transportation revenues	402	412	(10)	(2) %	803	798	5	1 %
Costs and Expenses								
Trucking costs	(29)	(41)	12	29 %	(59)	(78)	19	24 %
Field operating costs (2)	(209)	(137)	(72)	(53)%	(346)	(265)	(81)	(31)%
Equity-indexed compensation expense - operations	(3)	(5)	2	40 %	(6)	(10)	4	40 %
Segment general and administrative expenses (2) (3)	(22)	(21)	(1)	(5) %	(43)	(43)	—	— %
Equity-indexed compensation expense - general and administrative	(5)	(10)	5	50 %	(10)	(19)	9	47 %
Equity earnings in unconsolidated entities	52	23	29	126 %	89	44	45	102 %
Segment profit	$ 186	$ 221	$ (35)	(16)%	$ 428	$ 427	$ 1	— %
Maintenance capital	$ 33	$ 42	$ 9	21 %	$ 66	$ 76	$ 10	13 %
Segment profit per barrel	$ 0.45	$ 0.62	$ (0.17)	(27)%	$ 0.54	$ 0.61	$ (0.07)	(11)%

Average Daily Volumes (in thousands of barrels per day) (4)	Three Months Ended June 30, 2015	2014	Favorable/ (Unfavorable) Variance Volumes	%	Six Months Ended June 30, 2015	2014	Favorable/ (Unfavorable) Variance Volumes	%
Tariff activities								
Crude Oil Pipelines								
All American	18	38	(20)	(53) %	27	36	(9)	(25) %
Bakken Area Systems (5)	147	145	2	1 %	149	138	11	8 %
Basin / Mesa / Sunrise	858	714	144	20 %	839	729	110	15 %
BridgeTex	130	—	130	N/A	107	—	107	N/A
Cactus	62	—	62	N/A	31	—	31	N/A
Capline	169	121	48	40 %	161	123	38	31 %
Eagle Ford Area Systems (5)	308	209	99	47 %	286	199	87	44 %
Line 63 / Line 2000	108	106	2	2 %	122	116	6	5 %
Manito	48	44	4	9 %	51	44	7	16 %
Mid-Continent Area Systems	355	371	(16)	(4) %	363	349	14	4 %
Permian Basin Area Systems	836	759	77	10 %	795	759	36	5 %
Rainbow	116	108	8	7 %	117	114	3	3 %
Rangeland	56	65	(9)	(14) %	59	67	(8)	(12) %
Salt Lake City Area Systems (5)	122	130	(8)	(6) %	126	131	(5)	(4) %
South Saskatchewan	61	58	3	5 %	63	61	2	3 %
White Cliffs	41	24	17	71 %	44	24	20	83 %
Other	791	734	57	8 %	740	692	48	7 %
NGL Pipelines								
Co-Ed	57	55	2	4 %	59	56	3	5 %
Other	137	123	14	11 %	133	119	14	12 %
Tariff activities total	4,420	3,804	616	16 %	4,272	3,757	515	14 %
Trucking	109	127	(18)	(14) %	115	129	(14)	(11) %
Transportation segment total	4,529	3,931	598	15 %	4,387	3,886	501	13 %

(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) Volumes associated with assets employed through acquisitions and capital expansion projects represent total volumes (attributable to our interest) for the number of days we employed the assets divided by the number of days in the period.

(5) Area systems include volumes (attributable to our interest) from our investments in 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. Revenue from our pipeline capacity agreements generally reflects a negotiated amount. Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month.

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

Net Operating Revenues and Volumes. As noted in the table above, our total Transportation segment revenues, net of trucking costs, increased for the six months ended June 30, 2015 compared to the six months ended June 30, 2014 and were relatively consistent for the comparative three-month periods, while average daily volumes increased for each of the comparative periods presented. Our Transportation segment results were impacted by the following:

· North American Crude Oil Production and Related Expansion Projects — Production growth from the development of certain North American crude oil resource plays increased volumes and revenues on our existing pipeline systems over the comparative periods presented. We estimate that the impact of increased throughput and related infrastructure projects, most notably on our Eagle Ford Area Systems and certain pipelines in our Permian Basin Area Systems, and our recently constructed Cactus, Sunrise and Pascagoula pipelines, increased our revenues by $25 million and $45 million, respectively, for the three and six months ended June 30, 2015 compared to the three and six months ended June 30, 2014.

· Tariff Rates — Revenues on our pipelines are impacted by various tariff rate changes that may occur during the period, which include (i) rate increases or decreases on our intrastate and Canadian pipelines and fees on related system assets, (ii) the indexing of rates on our FERC regulated pipelines or (iii) other negotiated rate changes. We estimate that the net impact of such rate changes on our pipelines increased revenues by $10 million and $30 million for the three and six months ended June 30, 2015, respectively, compared to the three and six months ended June 30, 2014 primarily due to tariff rate increases on certain of our Canadian crude oil pipelines and incremental fees on related system assets, and, to a much lesser extent, the FERC indexing effective July 1, 2014 and rate increases on our intrastate pipelines.

· Loss Allowance Revenue — 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 revenues. The loss allowance revenue decreased by $18 million and $27 million, respectively, for the three and six months ended June 30, 2015 compared to the three and six months ended June 30, 2014 primarily due to a lower average realized price per barrel, partially offset by higher volumes.

· Foreign Exchange Impact — We estimate that revenues from our Canadian pipeline systems and trucking operations were unfavorably impacted by $12 million and $23 million for the three and six months ended June 30, 2015, respectively, compared to the three and six months ended June 30, 2014 due to the depreciation of CAD relative to USD.

Additional noteworthy volume and revenue variances for the comparative periods presented included (i) lower volumes and revenues on our All American Pipeline System due to pipeline downtime associated with the Line 901 incident (see Note 10 to our Condensed Consolidated Financial Statements for additional information), (ii) decreased trucking activity due to lower producer volumes and (iii) increased volumes and revenues on the Capline Pipeline System due to higher refinery demand and timing of a refinery turnaround, which occurred in the second quarter of 2014.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) increased during the three and six months ended June 30, 2015 compared to the three and six months ended June 30, 2014 primarily due to the following:

· Estimated costs of $65 million associated with the Line 901 incident, net of amounts we believe are probable of recovery from insurance. See Note 10 to our Condensed Consolidated Financial Statements for additional information regarding this incident.

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· Higher salary and related expenses and property tax expense primarily associated with the growth and capital expansion in the segment.

The increase in operating costs for the comparative periods was partially offset by favorable foreign exchange impacts of $4 million and $9 million for the three and six months ended June 30, 2015, respectively.

Equity-Indexed Compensation Expense. On a consolidated basis across all segments, equity-indexed compensation expense decreased for the three and six months ended June 30, 2015 compared to the same periods in 2014 primarily due to the impact of the decrease in unit price during each of the 2015 periods compared to the impact of the increase in unit price during the 2014 periods.

Allocations of equity-indexed compensation expense vary over time (i) between field operating costs and general and administrative expenses and (ii) between segments and could result in variances in those expense categories or segments that differ from the consolidated variance explanations above. See Note 16 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for additional information regarding our equity-indexed compensation plans.

Equity Earnings in Unconsolidated Entities. The favorable variance in equity earnings in unconsolidated entities for the three and six months ended June 30, 2015 compared to the three and six months ended June 30, 2014 was primarily driven by (i) earnings from our 50% interest in BridgeTex, which we acquired in November 2014, (ii) increased throughput on the White Cliffs pipeline due to an expansion of the pipeline that was placed into service in July 2014 and (iii) increased throughput on the Eagle Ford pipeline as a result of increased crude oil production, as discussed in “Net Operating Revenues and Volumes” above.

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, 2015 compared to the three and six months ended June 30, 2014 was primarily due to a reclassification of certain maintenance capital costs from our Facilities segment during the 2014 period.

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.

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

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The following tables set forth our operating results from our Facilities segment for the periods indicated:

Operating Results (1) (in millions, except per barrel data)	Three Months Ended June 30, 2015	2014	Favorable/ (Unfavorable) Variance $	%	Six Months Ended June 30, 2015	2014	Favorable/ (Unfavorable) Variance $	%
Revenues	$ 269	$ 277	$ (8)	(3) %	$ 525	$ 576	$ (51)	(9) %
Storage related costs (natural gas related)	(7)	(12)	5	42 %	(11)	(38)	27	71 %
Field operating costs (2)	(97)	(106)	9	8 %	(187)	(204)	17	8 %
Equity-indexed compensation expense - operations	(1)	(2)	1	50 %	(2)	(2)	—	— %
Segment general and administrative expenses (2) (3)	(17)	(16)	(1)	(6) %	(33)	(29)	(4)	(14) %
Equity-indexed compensation expense - general and administrative	(3)	(7)	4	57 %	(7)	(15)	8	53 %
Segment profit	$ 144	$ 134	$ 10	7 %	$ 285	$ 288	$ (3)	(1) %
Maintenance capital	$ 17	$ 5	$ (12)	(240) %	$ 32	$ 15	$ (17)	(113) %
Segment profit per barrel	$ 0.38	$ 0.37	$ 0.01	3 %	$ 0.38	$ 0.40	$ (0.02)	(5) %

Volumes (4)	Three Months Ended June 30, 2015	2014	Favorable/ (Unfavorable) Variance Volumes	%	Six Months Ended June 30, 2015	2014	Favorable/ (Unfavorable) Variance Volumes	%
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	99	94	5	5 %	99	95	4	4 %
Rail load / unload volumes (average volumes in thousands of barrels per day)	233	224	9	4 %	220	227	(7)	(3) %
Natural gas storage (average monthly working	97	97	—	— %	97	97	—	— %

capacity in billions of cubic feet)											
NGL fractionation (average volumes in thousands of barrels per day)	103	86	17	20	%	103	89	14	16	%
Facilities segment total (average monthly volumes in millions of barrels) (5)	126	120	6	5	%	125	121	4	3	%

(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) Volumes associated with assets employed through acquisitions and capital expansion projects represent total volumes for the number of months we employed the assets divided by the number of months in the period.

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

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

Net Operating Revenues and Volumes. As noted in the table above, our Facilities segment revenues, less storage related costs, decreased for the three and six months ended June 30, 2015 compared to the same periods in 2014, while total volumes for each of the comparative periods presented increased slightly. Our Facilities segment results for the comparative periods were impacted by:

· Rail Terminals — For the three and six months ended June 30, 2015, revenues from our rail activities decreased by $1 million and $10 million, respectively, due to lower rail fees related to the movement of certain volumes of Bakken crude oil, primarily to our St. James rail terminal, partially offset by revenues from our Bakersfield rail terminal that came online in the fourth quarter of 2014.

· NGL Storage, NGL Fractionation and Canadian Gas Processing Activities — Revenues from our NGL storage, NGL fractionation and Canadian gas processing activities increased by $2 million for the three month comparative periods presented and decreased by $4 million for the six month comparative periods. Both the three and six month periods in 2015 were favorably impacted by higher facility fees at certain of our storage and gas processing facilities, largely offset by unfavorable foreign currency effects of $8 million and $17 million for the three and six month comparative periods, respectively, due to the depreciation of CAD relative to USD. The six month comparative period was further unfavorably impacted by lower physical processing gains during 2015 related to component mix at our fractionation facilities and significantly lower NGL prices. NGL fractionation volumes increased for the 2015 periods due to higher NGL supply volumes from western Canada; however, there was not a corresponding increase in revenue as the impacted facilities charge a fixed monthly fee.

· Gulf Coast Gas Processing Activities — Revenues from our Gulf Coast gas processing activities decreased by $3 million and $7 million for the three and six months ended June 30, 2015, respectively, compared to the three and six months ended June 30, 2014, primarily due to lower volumes and decreased margins driven by lower commodity prices.

Additional noteworthy variances for the comparative periods presented included (i) lower revenues from our natural gas storage operations due to less favorable market conditions during the 2015 periods and (ii) higher volumes and revenues from our crude oil storage activities primarily resulting from capacity expansions at our St. James and Cushing terminals, partially offset by decreased demand for storage at certain of our California facilities.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the three and six months ended June 30, 2015 compared to the three and six months ended June 30, 2014 primarily due to a decrease in maintenance and repair costs and lower gas and power costs largely associated with our NGL fractionation and Canadian natural gas processing activities. These decreases were partially offset by higher property taxes and salary and related expenses primarily associated with rail facilities. Favorable foreign exchange effects of $5 million and $9 million for the comparable three and six month periods, respectively, further drove the decrease in field operating costs.

General and Administrative Expenses. The increase in general and administrative expenses (excluding equity-indexed compensation expense) during the six months ended June 30, 2015 over the comparable 2014 period was primarily due to a change in the allocation of shared costs and increased legal fees.

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Maintenance Capital. The increase in maintenance capital for the three and six months ended June 30, 2015 compared to the three and six months ended June 30, 2014 was primarily due to various tank and facility projects and timing of equipment replacements. The three month comparative period was also impacted by a change in classification in the three months ended June 30, 2014 of certain maintenance capital costs to our Transportation segment.

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, we expect our segment profit to increase or decrease directionally with (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchase volumes and NGL sales volumes), (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. We do not anticipate that future changes in revenues resulting from variances in commodity prices will be a primary driver of segment profit.

The following tables set forth our operating results from our Supply and Logistics segment for the periods indicated: