PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
May 10, 2016
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2016

OR

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

Commission File Number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

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

(713) 646-4100

(Registrant s telephone number, including area code)

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

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

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

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of May 2, 2016, there were 397,730,991 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 millions, except unit data)

	March 31, 2016	December 31, 2015
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 36	$ 27
Trade accounts receivable and other receivables, net	1,549	1,785
Inventory	877	916
Other current assets	318	241
Total current assets	2,780	2,969
PROPERTY AND EQUIPMENT	15,875	15,654
Accumulated depreciation	(2,205)	(2,180)
Property and equipment, net	13,670	13,474
OTHER ASSETS		
Goodwill	2,405	2,405
Investments in unconsolidated entities	2,097	2,027
Linefill and base gas	899	898
Long-term inventory	112	129
Other long-term assets, net	334	386
Total assets	$ 22,297	$ 22,288
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 1,979	$ 2,038
Short-term debt	715	999
Other current liabilities	369	370
Total current liabilities	3,063	3,407
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discounts and debt issuance costs	9,126	9,698
Other long-term debt	27	677
Other long-term liabilities and deferred credits	710	567
Total long-term liabilities	9,863	10,942
COMMITMENTS AND CONTINGENCIES (NOTE 10)		

PARTNERS CAPITAL				
Series A preferred unitholders (61,030,127 units outstanding)		1,509		
Common unitholders (397,730,991 and 397,727,624 units outstanding, respectively)		7,474		7,580
General partner		330		301
Total partners capital excluding noncontrolling interests		9,313		7,881
Noncontrolling interests		58		58
Total partners capital		9,371		7,939
Total liabilities and partners capital	$	22,297	$	22,288

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended March 31, 2016		Three Months Ended March 31, 2015	
	(unaudited)			
REVENUES				
Supply and Logistics segment revenues	$	3,819	$	5,632
Transportation segment revenues		154		185
Facilities segment revenues		138		125
Total revenues		4,111		5,942
COSTS AND EXPENSES				
Purchases and related costs		3,348		5,042
Field operating costs		300		346
General and administrative expenses		67		78
Depreciation and amortization		114		104
Total costs and expenses		3,829		5,570
OPERATING INCOME		282		372
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities		47		37
Interest expense (net of capitalized interest of $13 and $14, respectively)		(112)		(105)
Other income/(expense), net		5		(4)
INCOME BEFORE TAX		222		300
Current income tax expense		(31)		(42)
Deferred income tax benefit		12		26
NET INCOME		203		284
Net income attributable to noncontrolling interests		(1)		(1)
NET INCOME ATTRIBUTABLE TO PAA	$	202	$	283
NET INCOME PER COMMON UNIT (NOTE 3):				
Net income attributable to common unitholders Basic	$	28	$	136
Basic weighted average common units outstanding		398		383
Basic net income per common unit	$	0.07	$	0.36
Net income attributable to common unitholders Diluted	$	28	$	136
Diluted weighted average common units outstanding		399		385
Diluted net income per common unit	$	0.07	$	0.35

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended March 31, 2016		Three Months Ended March 31, 2015	
	(unaudited)			
Net income	$	203	$	284
Other comprehensive income/(loss)		118		(376)
Comprehensive income/(loss)		321		(92)
Comprehensive income attributable to noncontrolling interests		(1)		(1)
Comprehensive income/(loss) attributable to PAA	$	320	$	(93)

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 (unaudited)		Total	
Balance at December 31, 2015	$	(203)	$	(878)	$	(1,081)
Reclassification adjustments		1				1
Deferred loss on cash flow hedges		(90)				(90)
Currency translation adjustments				207		207
Total period activity		(89)		207		118
Balance at March 31, 2016	$	(292)	$	(671)	$	(963)

	Derivative Instruments		Translation Adjustments (unaudited)		Total	
Balance at December 31, 2014	$	(159)	$	(308)	$	(467)
Reclassification adjustments		(6)				(6)
Deferred loss on cash flow hedges		(72)				(72)
Currency translation adjustments				(298)		(298)
Total period activity		(78)		(298)		(376)

Balance at March 31, 2015	$ (237)	$ (606)	$ (843)

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 203	$ 284
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	114	104
Equity-indexed compensation expense	4	19
Inventory valuation adjustments	3	24
Deferred income tax benefit	(12)	(26)
Gain on foreign currency revaluation	(3)	(27)
Equity earnings in unconsolidated entities	(47)	(37)
Distributions from unconsolidated entities	52	54
Other	3	(6)
Changes in assets and liabilities, net of acquisitions	318	343
Net cash provided by operating activities	635	732
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions	(85)	(64)
Investments in unconsolidated entities	(75)	(65)
Additions to property, equipment and other	(372)	(441)
Cash paid for purchases of linefill and base gas		(96)
Proceeds from sales of assets	246	1
Other investing activities	(1)	(1)
Net cash used in investing activities	(287)	(666)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments under commercial paper program (Note 6)	(1,211)	(734)
Net repayments under senior secured hedged inventory facility (Note 6)	(300)	
Net proceeds from the sale of Series A preferred units and associated embedded derivative (Note 7)	1,570	
Net proceeds from the sale of common units		1,099
Contributions from general partner	33	22
Distributions paid to common unitholders (Note 7)	(278)	(254)
Distributions paid to general partner (Note 7)	(155)	(136)
Other financing activities	(2)	(3)
Net cash used in financing activities	(343)	(6)
Effect of translation adjustment on cash	4	(5)
Net increase in cash and cash equivalents	9	55
Cash and cash equivalents, beginning of period	27	403
Cash and cash equivalents, end of period	$ 36	$ 458
Cash paid for:		
Interest, net of amounts capitalized	$ 85	$ 74
Income taxes, net of amounts refunded	$ 16	$ 11

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS CAPITAL

(in millions)

	Limited Partners			Partners Capital		
	Series A Preferred Unitholders	Common Unitholders	General Partner	Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners Capital
			(unaudited)			
Balance at December 31, 2015	$	$ 7,580	$ 301	$ 7,881	$ 58	$ 7,939
Net income		55	147	202	1	203
Distributions		(278)	(155)	(433)	(1)	(434)
Sale of Series A preferred units	1,509		33	1,542		1,542
Other comprehensive income		115	3	118		118
Other		2	1	3		3
Balance at March 31, 2016	$ 1,509	$ 7,474	$ 330	$ 9,313	$ 58	$ 9,371

	Limited Partners Common Unitholders	General Partner	Partners Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners Capital
			(unaudited)		
Balance at December 31, 2014	$ 7,793	$ 340	$ 8,133	$ 58	$ 8,191
Net income	138	145	283	1	284
Distributions	(254)	(136)	(390)	(1)	(391)
Sale of common units	1,099	22	1,121		1,121
Other comprehensive loss	(369)	(7)	(376)		(376)
Other	6	1	7		7
Balance at March 31, 2015	$ 8,413	$ 365	$ 8,778	$ 58	$ 8,836

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Basis of Consolidation and Presentation

Organization

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

We own and operate midstream energy infrastructure and provide logistics services for crude oil, natural gas liquids (NGL), natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics. See Note 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 March 31, 2016, owned an approximate 43% 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

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Basis of Consolidation and Presentation

The accompanying unaudited condensed consolidated interim financial statements and related notes thereto should be read in conjunction with our 2015 Annual Report on Form 10-K. The accompanying condensed consolidated financial statements include the accounts of PAA and all of its wholly owned subsidiaries and those entities that it controls. Investments in entities over which we have significant influence but not control are accounted for by the equity method. The financial statements have been prepared in accordance with the instructions for interim reporting as set forth by the SEC. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. Such reclassifications include $3 million reclassified from Depreciation and amortization to Interest expense, net in our accompanying Condensed Consolidated Statements of Operations for the three months ended March 31, 2015 due to the retrospective application of revised debt issuance costs guidance issued by the FASB, which we adopted during the fourth quarter of 2015. These reclassifications do not affect net income attributable to PAA. The condensed consolidated balance sheet data as of December 31, 2015 was derived from audited financial statements, but does not include all disclosures required by GAAP. The results of operations for the three months ended March 31, 2016 should not be taken as indicative of results to be expected for the entire year.

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

Note 2 Recent Accounting Pronouncements

Except as discussed below and in our 2015 Annual Report on Form 10-K, there have been no new accounting pronouncements that have become effective or have been issued during the three months ended March 31, 2016 that are of significance or potential significance to us.

In February 2016, the FASB issued guidance that revises the current accounting model for leases. The most significant changes are the clarification of the definition of a lease and required lessee recognition on the balance sheet of lease assets and liabilities with lease terms of more than 12 months, including extensive quantitative and qualitative disclosures. This guidance will become effective for interim and annual periods beginning after December 15, 2018, with a modified retrospective application required. Early adoption is permitted, including adoption in an interim period. We expect to adopt this guidance on January 1, 2019, and we are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations and cash flows.

In March 2016, the FASB issued guidance to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification of certain related payments on the statement of cash flows. This guidance will become effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. We expect to adopt this guidance on January 1, 2017, and we are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations and cash flows.

Note 3 Net Income Per Common Unit

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

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

Diluted net income per common unit is computed based on the weighted average number of common units plus the effect of potentially dilutive securities outstanding during the period. When applying the if-converted method prescribed by FASB guidance, the possible conversion of our Series A preferred units was excluded from the calculation of diluted net income per common unit for the three months ended March 31, 2016 as the effect was antidilutive. See Note 7 to our Condensed Consolidated Financial Statements for additional information regarding our Series A preferred units. Our LTIP awards that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as

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prescribed by the treasury stock method in guidance issued by the FASB. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2015 Annual Report on Form 10-K for a complete discussion of our LTIP awards including specific discussion regarding DERs.

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

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Basic Net Income per Common Unit		
Net income attributable to PAA	$ 202	$ 283
Less: Distributions to Series A preferred units (1)	(23)	
Less: Distributions to general partner (1)	(155)	(148)
Less: Distributions to participating securities (1)	(1)	(2)
Less: Undistributed loss allocated to general partner (1)	5	3
Net income attributable to common unitholders in accordance with application of the two-class method for MLPs	$ 28	$ 136
Basic weighted average common units outstanding	398	383
Basic net income per common unit	$ 0.07	$ 0.36
Diluted Net Income per Common Unit		
Net income attributable to PAA	$ 202	$ 283
Less: Distributions to Series A preferred units (1)	(23)	
Less: Distributions to general partner (1)	(155)	(148)
Less: Distributions to participating securities (1)	(1)	(2)
Less: Undistributed loss allocated to general partner (1)	5	3
Net income attributable to common unitholders in accordance with application of the two-class method for MLPs	$ 28	$ 136
Basic weighted average common units outstanding	398	383
Effect of dilutive securities: Weighted average LTIP units	1	2
Diluted weighted average common units outstanding	399	385
Diluted net income per common unit	$ 0.07	$ 0.35

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

Pursuant to the terms of our partnership agreement, the general partner s incentive distribution is limited to a percentage of available cash, which, as defined in our partnership agreement, is net of reserves deemed appropriate. As such, IDRs are not allocated undistributed earnings or distributions in excess of earnings in the calculation of net income per common unit. If, however, undistributed earnings were allocated to our

IDRs beyond amounts distributed to them under the terms of our partnership agreement, basic and diluted net income per common unit as reflected in the table above would not have been impacted, as we did not have undistributed earnings for any of the periods presented.

Note 4 Accounts Receivable, Net

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL and natural gas. To mitigate credit risk related to our accounts receivable, we utilize a rigorous credit review process. We closely monitor market conditions to make a determination with respect to the amount, if any, of open credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of advance cash payments, standby letters of credit or parental guarantees. As of March 31, 2016 and December 31, 2015, we had received $52 million and $88 million, respectively, of advance cash payments from third parties to mitigate credit risk.

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We also received $26 million and $36 million as of March 31, 2016 and December 31, 2015, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. Additionally, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. Furthermore, we also enter into netting agreements (contractual agreements that allow us to offset receivables and payables with those counterparties against each other on our balance sheet) for a majority of such arrangements.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At March 31, 2016 and December 31, 2015, substantially all of our trade accounts receivable (net of allowance for doubtful accounts) were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $4 million at both March 31, 2016 and December 31, 2015. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

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

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

	March 31, 2016				December 31, 2015			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)
Inventory								
Crude oil	21,073	barrels	$ 711	$ 33.74	16,345	barrels	$ 608	$ 37.20
NGL	6,512	barrels	102	$ 15.66	13,907	barrels	218	$ 15.68
Natural gas	17,150	Mcf	34	$ 1.98	22,080	Mcf	53	$ 2.40
Other	N/A		30	N/A	N/A		37	N/A
Inventory subtotal			877				916	
Linefill and base gas								
Crude oil	12,060	barrels	711	$ 58.96	12,298	barrels	713	$ 57.98
NGL	1,348	barrels	47	$ 34.87	1,348	barrels	44	$ 32.64
Natural gas	30,812	Mcf	141	$ 4.58	30,812	Mcf	141	$ 4.58
Linefill and base gas subtotal			899				898	
Long-term inventory								
Crude oil	3,333	barrels	92	$ 27.60	3,417	barrels	106	$ 31.02
NGL	1,652	barrels	20	$ 12.11	1,652	barrels	23	$ 13.92
Long-term inventory subtotal			112				129	

Total			$	1,888			$	1,943

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

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 three months ended March 31, 2015 primarily related to the writedown of our NGL inventory due to declines in prices. 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.

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Note 6 Debt

Debt consisted of the following (in millions):

	March 31, 2016	December 31, 2015
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 0.9% and 1.1%, respectively (1)	$ 137	$ 696
Senior secured hedged inventory facility, bearing a weighted-average interest rate of 1.4% (1)		300
Senior notes:		
5.88% senior notes due August 2016	175	
6.13% senior notes due January 2017	400	
Other	3	3
Total short-term debt	715	999
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $74 and $77, respectively	9,126	9,698
Commercial paper notes, bearing a weighted-average interest rate of 0.9% and 1.1%, respectively	23	672
Other	4	5
Total long-term debt	9,153	10,375
Total debt (2)	$ 9,868	$ 11,374

(1) We classified these commercial paper notes and credit facility borrowings as short-term as of March 31, 2016 and December 31, 2015, as these notes and borrowings were primarily designated as working capital borrowings, were required to be repaid within one year and were primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

(2) Our fixed-rate senior notes (including current maturities) had a face value of approximately $9.8 billion as of both March 31, 2016 and December 31, 2015. We estimated the aggregate fair value of these notes as of March 31, 2016 and December 31, 2015 to be approximately $9.0 billion and $8.6 billion, respectively. Our fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near the end of the reporting period. We estimate that the carrying value of outstanding borrowings under our credit facilities and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities and commercial paper program are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the three months ended March 31, 2016 and 2015 were approximately $10.8 billion and $7.0 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $12.3 billion and $7.7 billion for the three months ended March 31, 2016 and 2015, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

Letters of Credit

In connection with our supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs, derivative transactions and construction activities. At March 31, 2016 and December 31, 2015, we had outstanding letters of credit of $45 million and $46 million, respectively.

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Note 7 Partners Capital and Distributions

Units Outstanding

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

	Limited Partners	
	Preferred Units	Common Units
Outstanding at December 31, 2015		397,727,624
Sale of Series A preferred units	61,030,127	
Issuance of common units under LTIP		3,367
Outstanding at March 31, 2016	61,030,127	397,730,991

	Limited Partners Common Units
Outstanding at December 31, 2014	375,107,793
Sale of common units	22,133,904
Outstanding at March 31, 2015	397,241,697

Equity Offerings

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

The Series A preferred units are a new class of equity security that ranks senior to all classes or series of our equity securities with respect to distribution rights and rights upon liquidation. The holders of the Series A preferred units will receive cumulative quarterly distributions, subject to customary antidilution adjustments, equal to an annual rate of 8% of the Issue Price ($2.10 per unit annualized). With respect to any quarter ending on or prior to December 31, 2017 (the Initial Distribution Period), we may elect to pay distributions on the Series A preferred units in additional preferred units, in cash or a combination of both. With respect to any quarter ending after the Initial Distribution Period, we must pay distributions on the Series A preferred units in cash. Our general partner will be entitled to participate in cash distributions on the Series A preferred units equal to its 2% general partner interest.

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

For a period of 30 days following (a) the fifth anniversary of the issuance date of the Series A preferred units and (b) each subsequent anniversary of the issuance date, the holders of the Series A preferred units, acting by majority vote, may make a one-time election to reset the distribution rate to equal the then applicable rate of the ten-year U.S. Treasury plus 5.85% (the Preferred Distribution Rate Reset Option). The Preferred Distribution Rate Reset Option is accounted for as an embedded derivative. See Note 8 for additional information. If the holders of the Series A preferred units have exercised the Preferred Distribution Rate Reset Option, then, at any time following 30 days after the sixth anniversary of the issuance date, we may redeem all or any portion of the outstanding Series A preferred units in exchange for cash, common units (valued at 95% of the volume-weighted average price of the common units for a trading day period specified in our partnership agreement) or a combination of cash and common units at a redemption price equal to 110% of the Issue Price, plus any accrued and unpaid distributions.

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Distributions

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

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

(1) Payable to unitholders of record at the close of business on April 29, 2016 for the period January 1, 2016 through March 31, 2016.

In-Kind Distributions. On May 13, 2016, we will issue 858,439 additional Series A preferred units in lieu of a cash distribution of $23 million. Such distribution is prorated for the period beginning on January 28, 2016, the issuance date of the Series A preferred units, through March 31, 2016 and will be issued to Series A preferred unitholders of record as of April 29, 2016. Since the May 13, 2016 Series A preferred unit distribution was declared as payment-in-kind, this distribution payable was accrued to partners capital as of March 31, 2016 and thus had no net impact on the Series A preferred unitholders capital account.

Noncontrolling Interests in Subsidiaries

As of March 31, 2016, noncontrolling interests in our subsidiaries consisted of a 25% interest in SLC Pipeline LLC.

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 throughout the hedging relationship, we assess whether the derivatives employed are highly effective in offsetting changes in cash flows of anticipated hedged transactions.

Commodity Price Risk Hedging

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

Commodity Purchases and Sales In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of March 31, 2016, net derivative positions related to these activities included:

- An average of 146,300 barrels per day net long position (total of 4.4 million barrels) associated with our crude oil purchases, which was unwound ratably during April 2016 to match monthly average pricing.

- A net short time spread position averaging 10,000 barrels per day (total of 4.3 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through June 2017.

- An average of 2,600 barrels per day (total of 1.2 million barrels) of crude oil grade spread positions through June 2017. These derivatives allow us to lock in grade basis differentials.

- A net short position of 13.9 Bcf through April 2017 related to anticipated sales of natural gas inventory and base gas requirements.

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- A net short position of 25.8 million barrels through December 2018 related to anticipated net sales of our crude oil and NGL inventory.

Pipeline Loss Allowance Oil As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We utilize derivative instruments to hedge a portion of the anticipated sales of the loss allowance oil that is to be collected under our tariffs. As of March 31, 2016, our material PLA hedges included a long call option position of 1.4 million barrels through December 2018.

Natural Gas Processing/NGL Fractionation We purchase natural gas for processing and operational needs. Additionally, we purchase NGL mix for fractionation and sell the resulting individual specification products (including ethane, propane, butane and condensate). In conjunction with these activities, we hedge the price risk associated with the purchase of the natural gas and the subsequent sale of the individual specification products. As of March 31, 2016, we had a long natural gas position of 14.0 Bcf through December 2016, a short propane position of 2.7 million barrels through December 2016, a short butane position of 0.8 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 0.4 million megawatt hours, which hedges a portion of our power supply requirements at our Canadian natural gas processing and fractionation plants through December 2018.

Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the normal purchases and normal sales scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings. We have determined that substantially all of our physical commodity contracts qualify for the normal purchases and normal sales scope exception.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated and outstanding interest payments occurring as a result of debt issuances. The derivative instruments we use to manage this risk consist of forward starting interest rate swaps and treasury locks. As of March 31, 2016, AOCI includes deferred losses of $270 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 March 31, 2016 (notional amounts in millions):

Hedged Transaction

	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	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

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use foreign currency derivatives to minimize the risk of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts and forwards.

As of March 31, 2016, our outstanding foreign currency derivatives include derivatives we use to hedge currency exchange risk (i) associated with USD-denominated commodity purchases and sales in Canada and (ii) created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

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The following table summarizes our open forward exchange contracts as of March 31, 2016 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2016	$ 147	$ 191	$1.00 - $1.30
Forward exchange contracts that exchange USD for CAD:				
	2016	$ 228	$ 302	$1.00 - $1.33

Preferred Distribution Rate Reset Option

A derivative feature embedded in a contract that does not meet the definition of a derivative in its entirety must be bifurcated and accounted for separately if the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract. The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value on our Condensed Consolidated Balance Sheets. Corresponding changes in fair value are recognized in Other income/(expense), net in our Condensed Consolidated Statement of Operations. At March 31, 2016, the fair value of this embedded derivative was a liability of approximately $60 million. See Note 7 for additional information regarding our Series A preferred units and the Preferred Distribution Rate Reset Option.

Summary of Financial Impact

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

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

	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
Location of Gain/(Loss)	Derivatives in Hedging Relationships	Derivatives Not Designated as a Hedge	Total	Derivatives in Hedging Relationships	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives						
Supply and Logistics segment revenues	$ 1	$ 31	$ 32	$ 7	$ (34)	$ (27)
Transportation segment revenues		2	2		2	2

Field operating costs		(2)	(2)		(4)	(4)
Interest Rate Derivatives						
Interest expense, net	(2)		(2)	(1)		(1)
Foreign Currency Derivatives						
Supply and Logistics segment revenues		6	6		(17)	(17)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (1)	$ 37	$ 36	$ 6	$ (53)	$ (47)

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The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of March 31, 2016 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives designated as hedging instruments:						
Commodity derivatives	Other current assets	$	3	Other current assets	$	(2)
Interest rate derivatives				Other current liabilities		(41)
				Other long-term liabilities and deferred credits		(97)
Total derivatives designated as hedging instruments		$	3		$	(140)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	170	Other current assets	$	(78)
	Other current liabilities		1	Other current liabilities		(13)
	Other long-term liabilities and deferred credits		2	Other long-term liabilities and deferred credits		(3)
Foreign currency derivatives	Other current assets		5			
Preferred Distribution Rate Reset Option				Other long-term liabilities and deferred credits		(60)
Total derivatives not designated as hedging instruments		$	178		$	(154)
Total derivatives		$	181		$	(294)

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

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

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

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through clearing brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of March 31, 2016, we had a net broker payable of $17 million (consisting of initial margin of $70 million reduced by $87 million of variation margin that had been returned to us). As of December 31, 2015, we had a net broker payable of $156 million (consisting of initial margin of $91 million reduced by $247 million of variation margin that had been returned to us).

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

	March 31, 2016		December 31, 2015	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 181	$ (294)	$ 280	$ (110)
Netting adjustment	(83)	83	(38)	38
Cash collateral received	(17)		(156)	
Net position - asset/(liability)	$ 81	$ (211)	$ 86	$ (72)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 81	$	$ 76	$
Other long-term assets, net			10	
Other current liabilities		(53)		(38)
Other long-term liabilities and deferred credits		(158)		(34)
	$ 81	$ (211)	$ 86	$ (72)

As of March 31, 2016, there was a net loss of $292 million deferred in AOCI. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transaction or (ii) interest expense accruals associated with underlying debt instruments. Of the total net loss deferred in AOCI at March 31, 2016, we expect to reclassify a net loss of $5 million to earnings in the next twelve months. The remaining deferred loss of $287 million is expected to be reclassified to earnings through 2049. A portion of these amounts is based on market prices as of March 31, 2016; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The following table summarizes the net deferred gain/(loss) recognized in AOCI for derivatives (in millions):

	Three Months Ended March 31,	
	2016	2015
Commodity derivatives, net	$	$ 3
Interest rate derivatives, net	(90)	(75)
Total	$ (90)	$ (72)

At March 31, 2016 and December 31, 2015, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings. Although we may be required to post margin on our cleared derivatives as described above, we do not require our non-cleared derivative counterparties to post collateral with us.

Recurring Fair Value Measurements

Derivative Financial Assets and Liabilities

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis (in millions):

	Fair Value as of March 31, 2016				Fair Value as of December 31, 2015			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 62	$ 17	$ 1	$ 80	$ 126	$ 90	$ 11	$ 227
Interest rate derivatives		(138)		(138)		(49)		(49)
Foreign currency derivatives		5		5		(8)		(8)
Preferred Distribution Rate Reset Option			(60)	(60)				
Total net derivative asset/(liability)	$ 62	$ (116)	$ (59)	$ (113)	$ 126	$ 33	$ 11	$ 170

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

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Level 1

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

Level 2

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

Level 3

Level 3 of the fair value hierarchy includes certain physical commodity contracts and the Preferred Distribution Rate Reset Option contained in our Series A preferred unit offering classified as an embedded derivative.

The fair value of our Level 3 physical commodity contracts is based on a valuation model utilizing broker-quoted forward commodity prices, and timing estimates, which involve management judgment. The significant unobservable inputs used in the fair value measurement of our Level 3 derivatives are forward prices obtained from brokers. A significant increase or decrease in these forward prices could result in a material change in fair value to our physical commodity contracts. We report unrealized gains and losses associated with these physical commodity contracts in our Condensed Consolidated Statements of Operations as Supply and Logistics segment revenues.

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

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

Rollforward of Level 3 Net Asset/(Liability)

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

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Beginning Balance	$ 11	$ 15
Losses for the period included in earnings	(1)	
Settlements	(9)	(12)
Derivatives entered into during the period	(60)	2
Ending Balance	$ (59)	$ 5
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	$ (1)	$ 2

Note 9 Related Party Transactions

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

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Transactions with Oxy

As of March 31, 2016, Oxy owned approximately 13% of the limited partner interests in our general partner and had a representative on the board of directors of GP LLC. During the three months ended March 31, 2016 and 2015, we recognized sales and transportation revenues and purchased petroleum products from Oxy. These transactions were conducted at posted tariff rates or prices that we believe approximate market. Included in these transactions was a crude oil buy/sell agreement that includes a multi-year minimum volume commitment. The impact to our Condensed Consolidated Statements of Operations from those transactions is included below (in millions):

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Revenues	$ 112	$ 176
Purchases and related costs (1)	$ (46)	$ 104

(1) Purchases and related costs include crude oil buy/sell transactions that are accounted for as inventory exchanges and are presented net in our Condensed Consolidated Statements of Operations.

We currently have a netting arrangement with Oxy. Our gross receivable and payable amounts with Oxy on our Condensed Consolidated Balance Sheets were as follows (in millions):

	March 31, 2016	December 31, 2015
Trade accounts receivable and other receivables	$ 474	$ 405
Accounts payable	$ 431	$ 363

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.

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.

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Environmental — General

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

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

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

At March 31, 2016, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident, as discussed further below) totaled $176 million, of which $69 million was classified as short-term and $107 million was classified as long-term. At December 31, 2015, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident) totaled $185 million, of which $81 million was classified as short-term and $104 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in "Accounts payable and accrued liabilities" and "Other long-term liabilities and deferred credits," respectively, on our Condensed Consolidated Balance Sheets. At March 31, 2016 and December 31, 2015, we had recorded receivables totaling $81 million and $161 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 or future legal claims giving rise to additional liabilities. Therefore, although we believe that the reserve is adequate, actual costs incurred (which may ultimately include costs for contingencies that are currently not reasonably estimable or costs for contingencies where the likelihood of loss is currently believed to be only reasonably possible or remote) may be in excess of the reserve and may potentially have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Specific Legal, Environmental or Regulatory Matters

Line 901 Incident. In May 2015, we experienced a crude oil release from our Las Flores to Gaviota Pipeline (Line 901) in Santa Barbara County, California. A portion of the released crude oil reached the Pacific Ocean at Refugio State Beach through a drainage culvert. Following the release, we shut down the pipeline and initiated our emergency response plan. A Unified Command, which includes the United States Coast Guard, the EPA, the California Office of Spill Prevention and Response and the Santa Barbara Office of Emergency Management, was established for the response effort. Clean-up and remediation operations with respect to impacted shoreline and other areas has been determined by the Unified Command to be complete, subject to continued shoreline monitoring. The cause of the release remains under investigation. Our current worst case estimate of the amount of oil spilled, representing the maximum volume of oil that we believed could have been spilled based on relevant facts, data and information, is approximately 2,935 barrels.

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

On May 21, 2015, we received a corrective action order from the United States Department of Transportation s Pipeline and Hazardous Materials Safety Administration (PHMSA), the governmental agency with jurisdiction over the operation of Line 901 as well as over a second stretch of pipeline extending from Gaviota Pump Station in Santa Barbara County to Emidio Pump Station in Kern County, California (Line 903), requiring us to shut down, purge, review, remediate and test Line 901. On June 3, 2015, the corrective action order was amended to require us to take additional corrective actions with respect to both Lines 901 and 903, and on November 13, 2015, the corrective action order was further amended to require the purge and shutdown of Line 903 between Gaviota and Pentland (as amended, the CAO). Among other requirements, the CAO also obligates us to conduct a root cause failure analysis with respect to Line 901 and present remedial work plans and restart plans to PHMSA prior to returning Line 901 and 903 to service; the CAO also imposes a pressure restriction on Line 903 and requires us to take other specified actions with respect to both Lines 901 and 903. We intend to continue to comply with the CAO and to cooperate with any other governmental investigations relating to or arising out of the release. Excavation and removal of the affected section of the pipeline was completed on May 28, 2015. Line 901 and Line 903 have been purged and are not currently operational. No timeline has been established for the restart of Line 901 or Line 903. On February 17, 2016, PHMSA issued a Preliminary Factual Report of the Line 901 failure, which contains PHMSA s preliminary findings regarding factual information about the events leading up to the accident and the technical analysis that has been conducted to date. By virtue of its statutory authority, PHMSA has the power and authority to impose fines and penalties on us and cause civil or criminal charges to be brought against us. While to date PHMSA has not imposed any such fines or penalties or pursued any such civil or criminal charges with respect to the Line 901 release, 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.

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

In late May of 2015, 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 already spoken to several of our employees and has expressed an interest in talking to other employees; consistent with the terms of our governing organizational documents, we are funding our employees defense costs, including the costs of separate counsel engaged to represent such individuals. In addition to the DOJ, the California Attorney General s Office and the District Attorney s Office for the County of Santa Barbara are also investigating the Line 901 incident to determine whether any applicable state or local laws have been violated. On August 26, 2015, we also received a Request for Information from the EPA relating to Line 901 and we are in the process of responding to such request. While to date no civil or criminal charges with respect to the Line 901 release have been brought against PAA or any of its affiliates, officers or employees by PHMSA, DOJ, EPA, California Attorney General or Santa Barbara County District Attorney, and no fines or penalties have been imposed by such governmental agencies, there can be no assurance that such fines or penalties will not be imposed upon us, our officers or our employees, or that such civil or criminal charges will not be brought against us, our officers or our employees in the future, whether by those or other governmental agencies.

Shortly following the Line 901 incident, we established a claims line and encouraged any parties that were damaged by the release to contact us to discuss their damage claims. We have received a number of claims through the claims line and we are processing those claims for payment as we receive them. In addition, we have also had eight class action lawsuits filed against us, seven of which have been administratively consolidated into a single proceeding in the United States District Court for the Central District of California. In general, the plaintiffs are seeking to establish different classes of claimants that have allegedly been damaged by the release, including potential classes such as persons that derive a significant portion of their income through commercial fishing and harvesting activities in the waters adjacent to Santa Barbara County or from businesses that are dependent on marine resources from Santa Barbara County, retail businesses located in historic downtown Santa Barbara, certain owners of oceanfront and/or beachfront property on the Pacific Coast of California, and other classes of individuals and businesses that were allegedly impacted by the release.

There have also been two securities law class action lawsuits filed on behalf of certain purported investors in the Partnership and/or PAGP against the Partnership, PAGP and/or certain of their respective officers, directors and underwriters. Both of these lawsuits have been consolidated into a single proceeding in the United States District Court for the Southern District of Texas. In general, these lawsuits allege that the various defendants violated securities laws by misleading investors regarding the integrity of the Partnership s pipelines and related facilities through false and misleading statements, omission of material facts and concealing of the true extent of the spill. The plaintiffs claim unspecified damages as a result of the reduction in value of their investments in the Partnership and PAGP, which they attribute to the alleged wrongful acts of the defendants. The Partnership and PAGP, and the other defendants, deny the allegations in these lawsuits and intend to respond accordingly. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we are indemnifying and funding the defense costs of our officers and directors in connection with these lawsuits; we are also indemnifying and funding the defense costs of our underwriters pursuant to the terms of the underwriting agreements we previously entered into with such underwriters.

In addition, three unitholder derivative lawsuits have been filed by certain purported investors in the Partnership against the Partnership, certain of its affiliates and certain officers and directors. Two of these lawsuits were filed in the United States District Court for the Southern District of Texas and the other was filed in State District Court in Harris County, Texas. In general, these lawsuits allege that the various defendants breached their fiduciary duties, engaged in gross mismanagement and made false and misleading statements, among other similar allegations, in connection with their management and oversight of the Partnership during the period of time leading up to and following the Line 901 release. The plaintiffs claim that the Partnership suffered unspecified damages as a result of the actions of the various defendants and seek to hold the defendants liable for such damages, in addition to other remedies. The defendants deny the allegations in these lawsuits and intend to respond accordingly. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we are indemnifying and funding the defense costs of our officers and directors in connection with these lawsuits.

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

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

Taking the foregoing into account, as of March 31, 2016, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $269 million, which estimate includes actual and projected emergency response and clean-up costs, natural resource damage assessments and certain third party claims settlements, as well as estimates for fines, penalties and certain legal fees. This estimate considers our prior experience in environmental investigation and remediation matters and available data from, and in consultation with, our environmental and other specialists, as well as currently available facts and presently enacted laws and regulations. We have made assumptions for (i) the expected number of days that monitoring services will be required, (ii) the duration of the natural resource damage assessment and the ultimate amount of damages determined, (iii) the resolution of certain third party claims and lawsuits, but excluding claims and lawsuits with respect to which losses are not probable and reasonably estimable, and excluding future claims and lawsuits, (iv) the determination and calculation of fines and penalties, but excluding fines and penalties that are not probable and reasonably estimable and (v) the nature, extent and cost of legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Line 901 incident. Our estimate does not include any lost revenue associated with the shutdown of Line 901 or 903 and does not include any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where we currently regard the likelihood of loss as being only reasonably possible or remote. We believe we have accrued adequate amounts for all probable and reasonably estimable costs; however, this estimate is subject to uncertainties associated with the assumptions that we have made. For example, the amount of time it takes for us to resolve all of the current and future lawsuits, claims and investigations that relate to the Line 901 incident could turn out to be significantly longer than we have assumed, and as a result the costs we incur for legal services could be significantly higher than we have estimated. In addition, with respect to fines and penalties, the ultimate amount of any fines and penalties assessed against us depends on a wide variety of factors, many of which are not estimable at this time. Where fines and penalties are probable and estimable, we have included them in our estimate, although such estimates could turn out to be wrong. Accordingly, our assumptions and estimates may turn out to be inaccurate and our total costs could turn out to be materially higher; therefore, we can provide no assurance that we will not have to accrue significant additional costs in the future with respect to the Line 901 incident.

As of March 31, 2016, we had a remaining undiscounted gross liability of $104 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 Sheet. We maintain insurance coverage, which is subject to certain exclusions and deductibles, in the event of such environmental liabilities. Subject to such exclusions and deductibles, we believe that our coverage is adequate to cover the current estimated total emergency response and clean-up costs, claims settlement costs and remediation costs and we believe that this coverage is also adequate to cover any potential increase in the estimates for these costs that exceed the amounts currently identified. Through March 31, 2016, we had collected, subject to customary reservations, $112 million out of the approximate $186 million of release costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of March 31, 2016, we have recognized a receivable of approximately $74 million for the portion of the release costs that we believe is probable of recovery from insurance, net of deductibles and amounts already collected. 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 Sheet. We have substantially completed the clean-up and remediation efforts, excluding long-term site monitoring activities; however, we expect to make payments for additional costs associated with restoration and monitoring of the area, as well as natural resource damage assessment, legal, professional and regulatory costs, in addition to fines and penalties, during future periods.

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MP29 Release. On July 10, 2015, we experienced a crude oil release of approximately 100 barrels at our Pocahontas Pump Station near the border of Bond and Madison Counties in Illinois, approximately 40 miles from St. Louis, Missouri. The Pocahontas Station is part of the Capwood pipeline that runs from our Patoka Station to Wood River, Illinois. A portion of the released crude oil was contained within our Pocahontas facility, but some of the released crude oil entered a nearby waterway where it was contained with booms. On July 14, 2015, PHMSA issued a corrective action order requiring us to take various actions in response to the release, including remediation, reporting and other actions. As of December 18, 2015, we had submitted all requested information and reports required by the corrective action order and are currently awaiting PHMSA s comment or approval. On August 10, 2015, we received a Notice of Violation from the Illinois Environmental Protection Agency (the Agency) alleging violations relating to the release and outlining the activities recommended by the Agency to resolve the alleged violations, including the completion of an investigation and various remediation activities. The Agency approved a work plan describing remediation activities proposed for remaining hydrocarbons at Pocahontas Station and affected waterways. Remediation activities under this work plan have effectively been completed, and on December 17, 2015, we entered into a Compliance Commitment Agreement with the Agency, which provides the framework for final completion and documentation of the remediation effort. 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, which was subsequently voluntarily dismissed by the plaintiff. We estimate that the aggregate total costs associated with this release will be less than $10 million.

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

Mesa to Basin Pipeline. On January 6, 2016, PHMSA issued a Notice of Probable Violation and Proposed Civil Penalty relating to an approximate 500 barrel release of crude oil that took place on January 1, 2015 on our Mesa to Basin 12 pipeline in Midland, Texas. PHMSA conducted an accident investigation and reviewed documentation related to the incident, and concluded that we had committed probable violations of certain pipeline safety regulations. In the Notice, PHMSA maintains that we failed to carry out our written damage prevention program and to follow our pipeline excavation/ditching and backfill procedures on four separate occasions, and that such failures resulted in outside force damage that led to the January 1, 2015 release. PHMSA s compliance officer has recommended that we be assessed a civil penalty of $190,000. We have formally responded to PHMSA regarding this matter, but at this point we can provide no assurance regarding the final disposition of this matter or the final amount of any civil penalties.

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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 (in millions):

Three Months Ended March 31, 2016	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External Customers	$ 154	$ 138	$ 3,819	$ 4,111
Intersegment (1)	229	127	2	358
Total revenues of reportable segments	$ 383	$ 265	$ 3,821	$ 4,469
Equity earnings in unconsolidated entities	$ 47	$	$	$ 47
Segment profit (2) (3)	$ 247	$ 159	$ 37	$ 443
Maintenance capital	$ 35	$ 9	$ 3	$ 47

Three Months Ended March 31, 2015	Transportation	Facilities	Supply and Logistics	Total
Revenues:				
External Customers	$ 185	$ 125	$ 5,632	$ 5,942
Intersegment (1)	215	132	2	349
Total revenues of reportable segments	$ 400	$ 257	$ 5,634	$ 6,291
Equity earnings in unconsolidated entities	$ 37	$	$	$ 37
Segment profit (2) (3)	$ 241	$ 142	$ 130	$ 513
Maintenance capital	$ 33	$ 15	$ 2	$ 50

(1) Segment revenues include intersegment amounts that are eliminated in Purchases and related costs and Field operating costs in our Condensed Consolidated Statements of Operations. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market at the time the agreement is executed or renegotiated. For further discussion, see Analysis of Operating Segments under Item 7 of our 2015 Annual Report on Form 10-K.

(2) Supply and Logistics segment profit includes interest expense (related to hedged inventory purchases) of $2 million and $1 million for the three months ended March 31, 2016 and 2015, respectively.

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

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Segment profit	$ 443	$ 513
Depreciation and amortization	(114)	(104)
Interest expense, net	(112)	(105)
Other income/(expense), net	5	(4)
Income before tax	222	300
Income tax expense	(19)	(16)
Net income	203	284
Net income attributable to noncontrolling interests	(1)	(1)
Net income attributable to PAA	$ 202	$ 283

Note 12 Acquisitions and Dispositions

Acquisitions. During the first quarter of 2016, we completed one acquisition for cash consideration of $85 million. We did not recognize any goodwill related to this acquisition.

Dispositions. In the first quarter of 2016, we entered into definitive agreements to sell several non-core assets. A portion of these transactions closed in March, and we expect the sale of the remaining assets to be consummated in the second quarter of 2016, subject to customary closing conditions, as applicable. As of March 31, 2016, we classified approximately $120 million of assets as held for sale on our Condensed Consolidated Balance Sheet (in Other current assets). During the three months ended March 31, 2016, we recognized gains of approximately $56 million and impairment losses of $50 million related to these non-core asset sales, including $15 million of impairment of goodwill included in a disposal group classified as held for sale. These gains and impairment losses are included in Depreciation and amortization on our Condensed Consolidated Statement of Operations.

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical Consolidated Financial Statements and accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2015 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the Condensed Consolidated Financial Statements and related notes that are contained in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Our discussion and analysis includes the following:

- Executive Summary
- Acquisitions and Capital Projects
- Results of Operations
- Outlook
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Recent Accounting Pronouncements

- Critical Accounting Policies and Estimates

- Forward-Looking Statements

Executive Summary

Company Overview

We own and operate midstream energy infrastructure and provide logistics services for crude oil, NGL, natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: Transportation, Facilities and Supply and Logistics. See Results of Operations Analysis of Operating Segments for further discussion.

Overview of Operating Results, Capital Investments and Other Significant Activities

During the first three months of 2016, we recognized net income attributable to PAA of $202 million as compared to net income attributable to PAA of $283 million recognized during the first three months of 2015. These results reflect growth in our Transportation and Facilities segments offset by:

- Lower operating results, primarily from our Supply and Logistics segment. See further discussion of our segment results in the Results of Operations Analysis of Operating Segments section below; and

- Higher depreciation and amortization expense and interest expense primarily associated with our capital expansion projects and related financing activities.

We invested approximately $370 million in midstream infrastructure projects during the three months ended March 31, 2016, with a targeted expansion capital plan for the full year of 2016 of approximately $1.5 billion. To fund such capital activities, during the quarter we completed (i) the private placement of approximately 61.0 million Series A preferred units for net proceeds of approximately $1.6 billion, including our general partner s proportionate capital contribution and (ii) the sale of various non-core assets for proceeds of approximately $250 million. In addition, we paid $433 million of cash distributions to our common unitholders and general partner during the three months ended March 31, 2016, and we declared a quarterly distribution of $0.70 per common unit to be paid on May 13, 2016.

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Acquisitions and Capital Projects

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

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Acquisition capital (1)	$ 85	$ 64
Expansion capital (1) (2)	370	586
Maintenance capital (2)	47	50
	$ 502	$ 700

(1) Acquisitions of initial investments or additional interests in unconsolidated entities are included in Acquisition capital. Subsequent contributions to unconsolidated entities related to expansion projects of such entities are recognized in Expansion capital. We account for our investments in such entities under the equity method of accounting.

(2) Capital expenditures made to expand the existing operating and/or earnings capacity of our assets are classified as expansion capital. Capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets are classified as maintenance capital.

Expansion Capital Projects

The following table summarizes our notable projects in progress during 2016 and the forecasted expenditures for the year ending December 31, 2016 (in millions):

Projects	**2016**
Red River Pipeline (Cushing to Longview)	$285
Diamond Pipeline	235
Permian Basin Area Pipeline Projects	210
Fort Saskatchewan Facility Projects	190
Saddlehorn Pipeline	150
Cushing Terminal Expansions	70
St. James Terminal Expansions	45
Caddo Pipeline	30
Cactus Pipeline	20
Eagle Ford JV Project	20
Other Projects	245

	$1,500
Potential Adjustments for Timing / Scope Refinement (1)	-$100 + $100
Total Projected Expansion Capital Expenditures	$1,400 - $1,600
Maintenance Capital Expenditures	$190 - $210

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

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Results of Operations

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

	Three Months Ended March 31,		Favorable/(Unfavorable) Variance	
	2016	2015	$	%
Transportation segment profit	$ 247	$ 241	$ 6	2%
Facilities segment profit	159	142	17	12%
Supply and Logistics segment profit	37	130	(93)	(72)%
Total segment profit	443	513	(70)	(14)%
Depreciation and amortization	(114)	(104)	(10)	(10)%
Interest expense, net	(112)	(105)	(7)	(7)%
Other income/(expense), net	5	(4)	9	225%
Income tax expense	(19)	(16)	(3)	(19)%
Net income	203	284	(81)	(29)%
Net income attributable to noncontrolling interests	(1)	(1)		%
Net income attributable to PAA	$ 202	$ 283	$ (81)	(29)%
Basic net income per common unit	$ 0.07	$ 0.36	$ (0.29)	(81)%
Diluted net income per common unit	$ 0.07	$ 0.35	$ (0.28)	(80)%
Basic weighted average common units outstanding	398	383	15	4%
Diluted weighted average common units outstanding	399	385	14	4%

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 derivative activities that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and business outlook and/or (v) other items that we believe should be excluded in understanding our core operating performance. These measures may further be adjusted to include amounts related to deficiencies associated with minimum volume commitments whereby we have billed the counterparties for their deficiency obligation and such amounts are recognized as deferred revenue in Accounts payable and accrued liabilities in our Condensed Consolidated Financial Statements. Such amounts are presented net of applicable amounts subsequently recognized into revenue. We have defined all such items 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 (in millions):

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Net income	$ 203	$ 284	$ (81)	(29)%
Add:				
Interest expense, net	112	105	7	7%
Income tax expense	19	16	3	19%
Depreciation and amortization	114	104	10	10%
EBITDA	$ 448	$ 509	$ (61)	(12)%
Selected Items Impacting Comparability of EBITDA				
Gains/(losses) from derivative activities net of inventory valuation adjustments (1)	$ (122)	$ (91)	$ (31)	(34)%
Long-term inventory costing adjustments (2)	(23)	(38)	15	39%
Equity-indexed compensation expense (3)	(4)	(11)	7	64%
Net gain/(loss) on foreign currency revaluation (4)	3	27	(24)	(89)%
Deficiencies under minimum volume commitments, net (5)	(27)		(27)	N/A
Selected Items Impacting Comparability of EBITDA	$ (173)	$ (113)	$ (60)	(53)%
EBITDA	$ 448	$ 509	$ (61)	(12)%
Selected Items Impacting Comparability of EBITDA	173	113	60	53%
Adjusted EBITDA	$ 621	$ 622	$ (1)	%
Adjusted EBITDA	$ 621	$ 622	$ (1)	%
Interest expense, net (6)	(108)	(101)	(7)	(7)%
Maintenance capital (7)	(47)	(50)	3	6%
Current income tax expense	(31)	(42)	11	26%
Equity earnings in unconsolidated entities, net of distributions	5	17	(12)	(71)%
Distributions to noncontrolling interests (8)	(1)	(1)		%
Implied DCF	$ 439	$ 445	$ (6)	(1)%
Less: Cash distributions (8)	(433)	(420)		
DCF Excess/(Shortage) (9)	$ 6	$ 25		

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(1) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining Adjusted EBITDA. In addition, we exclude gains and losses on derivatives that are related to investing activities, such as the purchase of linefill. We also exclude the impact of corresponding inventory valuation adjustments, as applicable. See Note 8 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

(2) We carry approximately 5 million barrels of crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and writedowns of such inventory that result from price declines as a selected item impacting comparability. See Note 4 to our Consolidated Financial Statements included in Part IV of our 2015 Annual Report on Form 10-K for a complete discussion of our long-term inventory.

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(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 net income per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted net income per unit calculation and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2015 Annual Report on Form 10-K for a comprehensive discussion regarding our equity-indexed compensation plans.

(4) During the three months ended March 31, 2016 and 2015, there were fluctuations in the value of CAD to USD, resulting in gains and losses that were not related to our core operating results for the period and were thus classified as a selected item impacting comparability.

(5) We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Some of these agreements include make-up rights if the minimum volume is not met. We record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty s make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty s ability to utilize the make-up right is remote. We include the impact of amounts billed to counterparties for their deficiency obligation, net of applicable amounts subsequently recognized into revenue, as a selected item impacting comparability.

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

(7) 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.

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

(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 or commercial paper program.

Analysis of Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 18 to our Consolidated Financial Statements included in Part IV of our 2015 Annual Report on Form 10-K for further discussion of how we evaluate segment profit. See Note 11 to our Condensed Consolidated Financial Statements for a reconciliation of segment profit to net income attributable to PAA.

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

Transportation Segment

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

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

Operating Results (1) (in millions, except per barrel data)	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Revenues				
Tariff activities	$ 349	$ 358	$ (9)	(3)%
Trucking	34	42	(8)	(19)%
Total transportation revenues	383	400	(17)	(4)%
Costs and expenses				
Trucking costs	(21)	(30)	9	30%
Field operating costs (2)	(137)	(136)	(1)	(1)%
Equity-indexed compensation expense - operations		(3)	3	100%
Segment general and administrative expenses (2) (3)	(23)	(22)	(1)	(5)%
Equity-indexed compensation expense - general and administrative	(2)	(5)	3	60%
Equity earnings in unconsolidated entities	47	37	10	27%
Segment profit	$ 247	$ 241	$ 6	2%
Maintenance capital	$ 35	$ 33	$ (2)	(6)%
Segment profit per barrel	$ 0.59	$ 0.63	$ (0.04)	(6)%

Average Daily Volumes (in thousands of barrels per day) (4)	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %
Tariff activities volumes				
Crude oil pipelines (by region):				
Permian Basin (5)	2,045	1,658	387	23%
South Texas / Eagle Ford (5)	313	263	50	19%
Western	175	268	(93)	(35)%
Rocky Mountain (5)	437	453	(16)	(4)%
Gulf Coast	581	441	140	32%
Central	379	435	(56)	(13)%
Canada	394	414	(20)	(5)%
Crude oil pipelines	4,324	3,932	392	10%
NGL pipelines	178	191	(13)	(7)%
Tariff activities total volumes	4,502	4,123	379	9%
Trucking	106	121	(15)	(12)%
Transportation segment total volumes	4,608	4,244	364	9%

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

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

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

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

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

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged, as well as the fixed and variable field costs of operating the pipeline. As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in

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transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff activities revenues. Revenue from our pipeline capacity agreements generally reflects a negotiated amount.

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

Net Operating Revenues, Equity Earnings and Volumes. As noted in the table above, our total Transportation segment revenues, net of trucking costs, decreased for the three months ended March 31, 2016 compared to the same period in 2015, while equity earnings in unconsolidated entities and average daily volumes increased over this period.

The following table presents significant net revenue and equity earnings variances by region for the comparative period presented:

	Favorable/(Unfavorable) Variance	
(in millions)	**Net Revenues**	**Equity Earnings**
Tariff activities:		
Permian Basin region	$ 32	$ 7
Western region	(12)	
Canada crude oil pipelines	(8)	
Other (including pipeline loss allowance revenue)	(21)	3
Tariff activities total	$ (9)	$ 10

- Permian Basin region The increase in revenues was largely driven by results from (i) our Cactus pipeline, which was placed in service in April 2015 and also impacted volumes on our McCamey pipeline system and our 50% interest in the Eagle Ford Joint Venture pipeline, and (ii) higher volumes associated with the expansion of our pipeline systems in the Delaware Basin.

The increase in equity earnings was driven by higher earnings from our interest in BridgeTex, which was in a ramp-up phase in the first quarter of 2015, and was not in full service until mid-2015.

- Western region Revenues and volumes decreased primarily due to (i) pipeline downtime on our All American Pipeline associated with the Line 901 incident that occurred in the second quarter of 2015 and (ii) refinery downtime in the Los Angeles area impacting our Line 63/Line 2000 pipelines, gathered volumes on our SJV system and rail volumes into our Bakersfield terminal. See Note 10 to our Condensed Consolidated Financial Statements for additional information regarding the Line 901 incident.

- Canada crude oil pipelines   Revenues decreased primarily due to estimated unfavorable foreign exchange impacts of $7 million and lower volumes, which offset increases from higher tariff rates on certain of our pipelines and related system assets.

- Other   The decrease was primarily related to lower pipeline loss allowance revenue of $18 million driven by a lower average realized price per barrel, partially offset by higher volumes. Additionally, volumes increased in the Gulf Coast region, which was primarily associated with increased movements on certain pipelines that are subject to long-term commitments with annual service payments; as such, these volume fluctuations did not have a meaningful impact on revenue.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) for the three months ended March 31, 2016 compared to the three months ended March 31, 2015 increased slightly primarily due to higher integrity management costs substantially offset by lower utilities costs and a favorable foreign exchange impact of $3 million.

Equity-Indexed Compensation Expense. On a consolidated basis, equity-indexed compensation expense decreased by $15 million for the three months ended March 31, 2016 compared to the same period in 2015, primarily due to the impact of lower unit prices during the 2016 period compared to the unit prices for the same period in 2015.

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

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.

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

Operating Results (1) **(in millions, except per barrel data)**	**Three Months Ended March 31, 2016**	**2015**	**Favorable/(Unfavorable) Variance $**	**%**
Revenues	$ 265	$ 257	$ 8	3%
Natural gas related storage costs	(5)	(4)	(1)	(25)%
Field operating costs (2)	(85)	(91)	6	7%
Equity-indexed compensation expense - operations		(1)	1	100%
Segment general and administrative expenses (2) (3)	(15)	(15)		%
Equity-indexed compensation expense - general and administrative	(1)	(4)	3	75%
Segment profit	$ 159	$ 142	$ 17	12%
Maintenance capital	$ 9	$ 15	$ 6	40%
Segment profit per barrel	$ 0.42	$ 0.38	$ 0.04	11%

Volumes (4)	**Three Months Ended March 31, 2016**	**2015**	**Favorable/(Unfavorable) Variance Volumes**	**%**
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	105	99	6	6%
Rail load / unload volumes (average volumes in thousands of barrels per day)	91	206	(115)	(56)%
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	97		%
NGL fractionation (average volumes in thousands of barrels per day)	115	102	13	13%
Facilities segment total (average monthly volumes in millions of barrels) (5)	127	124	3	2%

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

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

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

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

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

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

Net Operating Revenues and Volumes. As noted in the table above, our Facilities segment revenues, net of related costs, increased by $7 million for the three months ended March 31, 2016 as compared to the same period in 2015, and total volumes increased slightly. Our Facilities segment results for the comparative periods were impacted by:

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- Crude Oil Storage   Revenues increased by $14 million due to increased utilization at certain of our West Coast terminals and aggregate capacity expansions of approximately 4 million barrels at our St. James and Cushing terminals.

- Rail Terminals   Revenues from our rail activities decreased by $8 million primarily due to lower volumes as a result of less favorable market conditions.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased during the three months ended March 31, 2016 compared to the three months ended March 31, 2015 primarily due to lower costs related to contract services, primarily at our rail terminals and, to a lesser extent, at our processing facilities. The decrease in field operating costs was also impacted by a $3 million favorable foreign exchange effect.

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 months ended March 31, 2016 compared to the three months ended March 31, 2015 was primarily due to lower spending on various tank and other maintenance capital projects, partially due to timing.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes purchased from suppliers and natural gas sales attributable to the activities performed by our natural gas storage commercial optimization group. Generally, our segment profit is impacted by (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchases volumes, NGL sales volumes and waterborne cargos), (ii) demand for lease gathering services we provide producers and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although segment profit may be adversely affected during certain transitional periods as discussed further below, our crude oil and NGL supply, logistics and distribution operations are not directly affected by the absolute level of prices, but are affected by overall levels of supply and demand for crude oil and NGL and relative fluctuations in market-related indices.

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

Operating Results (1) (in millions, except per barrel data)	Three Months Ended March 31, 2016	 2015	Favorable/(Unfavorable) Variance $	 %
Revenues	$ 3,821	$ 5,634	$ (1,813)	(32)%
Purchases and related costs (2)	(3,677)	(5,353)	1,676	31%

Field operating costs (3)	(81)	(118)	37	31%
Equity-indexed compensation expense - operations		(1)	1	100%
Segment general and administrative expenses (3) (4)	(25)	(27)	2	7%
Equity-indexed compensation expense - general and administrative	(1)	(5)	4	80%
Segment profit	$ 37	$ 130	$ (93)	(72)%
Maintenance capital	$ 3	$ 2	$ (1)	(50)%
Segment profit per barrel	$ 0.33	$ 1.14	$ (0.81)	(71)%

Average Daily Volumes (in thousands of barrels per day)	**Three Months Ended March 31, 2016**	**2015**	**Favorable/(Unfavorable) Variance Volumes**	**%**
Crude oil lease gathering purchases	913	981	(68)	(7)%
NGL sales	308	286	22	8%
Waterborne cargos	7		7	N/A
Supply and Logistics segment total	1,228	1,267	(39)	(3)%

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(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of $2 million and $1 million for the three months ended March 31, 2016 and 2015, respectively.

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

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

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

	NYMEX WTI Crude Oil Price	
	Low	**High**
Three months ended March 31, 2016	$ 26	$ 41
Three months ended March 31, 2015	$ 43	$ 54

Because the commodities that we buy and sell are generally indexed to the same pricing indices for both sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases decreased for the three months ended March 31, 2016 compared to the same period in 2015 due to lower crude oil and NGL prices.

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

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

Net Operating Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs, decreased by $137 million for the three months ended March 31, 2016 compared to the three months ended March 31, 2015. The following summarizes the more significant items impacting the comparative periods:

- Crude Oil Operations Net revenues from our crude oil supply and logistics activities decreased for the three months ended March 31, 2016 as compared to the same period in 2015, primarily due to increased competition, largely due to overbuilt infrastructure and volume declines in certain areas, that has negatively impacted our lease gathering unit margins, partially offset by favorable results related to contango market opportunities.

- NGL Operations Net revenues from our NGL operations decreased for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015, primarily due to softer propane sales margins resulting from a shorter and milder winter in North America, and lower sales levels in the Eastern Canadian market.

- Foreign Exchange Impacts Our results are impacted by fluctuations in the value of CAD to USD, resulting in foreign exchange gains and losses on U.S. denominated net assets within our Canadian operations. The changes in exchange rates during each quarter resulted in net losses of $1 million for the three months ended March 31, 2016 as compared to net gains of $32 million for the three months ended March 31, 2015.

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

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Variance $
Losses from certain derivative activities net of inventory valuation adjustments (1)	$ (124)	$ (93)	$ (31)

(1) Includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in another period (or the reversal of mark-to-market gains and losses from a prior

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period), gains and losses on certain derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable. See Note 8 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

- Long-Term Inventory Costing Adjustment Our operating results are impacted by changes in the weighted average cost of our crude oil and NGL inventory pools that result from price movements during the periods. Such costing adjustments resulted in unfavorable impacts of $23 million and $38 million for the three months ended March 31, 2016 and 2015, respectively, due to price decreases during each period. These costing adjustments related to long-term inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that was needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future.

Field Operating Costs. The decrease in field operating costs (excluding equity-indexed compensation expense) for the three months ended March 31, 2016 compared to the three months ended March 31, 2015 was primarily due to a combination of (i) lower lease gathering volumes, (ii) shorter truck hauls as pipeline expansion projects were placed into service and (iii) a decrease in fuel prices.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense increased for the three months ended March 31, 2016 compared to the three months ended March 31, 2015 due to various capital expansion projects completed since March 31, 2015 and the write-off of costs associated with the discontinuation of certain projects. These items were partially offset by a net gain of approximately $6 million associated with entering into agreements to sell several non-core assets.

Interest Expense

The increase in interest expense for the three months ended March 31, 2016 over the three months ended March 31, 2015 was primarily due to a higher weighted average debt balance largely driven by our August 2015 $1.0 billion senior note issuance, partially offset by the maturity of $150 million and $400 million of our senior notes in June 2015 and September 2015, respectively.

Other Income/(Expense), Net

Other income/(expense), net in each of the periods presented was primarily comprised of foreign currency gains or losses related to revaluations of CAD-denominated interest receivables associated with our intercompany notes.

Income Tax Expense

Income tax expense increased for the three months ended March 31, 2016 compared to the three months ended March 31, 2015 primarily due to the deferred income tax impact associated with fluctuations in the derivative mark-to-market valuation in our Canadian operations, partially offset by lower year-over-year taxable earnings from our Canadian operations.

Outlook

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays, which occurred contemporaneously with attractive crude oil and liquids prices, during the approximately three year period through the end of 2014, U.S. crude oil and liquids production in the lower 48 states increased rapidly. This was particularly true for light crudes and condensates. Similar resource development activities in Canada and ongoing oil sands development activities also led to increased Canadian crude oil production during this period. Additionally, during this period, the crude oil market experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude oil qualities, international supply issues, and regional downstream operating issues. During 2013 and to a lesser degree 2014, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment.

However, the combination during such period of surging North American liquids production, relatively flat liquids production for the rest of the world and relatively modest growth in global liquids demand led to a supply imbalance, which in turn led to a significant and rapid reduction in petroleum prices. While we believe that our business model and asset base have minimal direct

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exposure to petroleum prices, our performance is influenced by certain differentials and overall North American production levels, which in turn are impacted by major price movements. The meaningful decrease in crude oil price levels during the second half of 2014 and throughout 2015 relative to the levels experienced during 2013 and the first half of 2014 have led many producers, including North American producers, to significantly scale back capital programs. As a result, during 2015 and through the first quarter of 2016, the rate of growth of North American crude oil production slowed significantly and began to decrease in some areas as producers have taken rigs out of service and deferred completions at an increased rate. The pace and depth of the reduction in drilling and completion activities by producers has been greater than anticipated by many market participants and observers; since the beginning of 2015, onshore rig counts for the lower 48 States have decreased approximately 80%. As a result of the combined effect of such reduced activity levels and the high decline rates for many of the producing wells that contribute towards current lower 48 onshore production levels, crude oil production declines are expected to continue during 2016 and potentially beyond in a number of onshore plays. While we believe that the larger North American resource base remains intact and will ultimately be developed, such production will likely take place at a slower pace and previously anticipated peak production levels will likely be reduced. This slowdown and reduction in North American production coupled with past increases in infrastructure has led to a compression of basis differentials in a number of locations. This transitioning crude oil market presents challenges to our business model and asset base and will likely impact the rate of cash flow and distribution growth that we would have otherwise experienced over the next several years. In addition, increased competition and compressed differentials may drive lower volumes and lower unit margins in parts of our business, particularly our Supply and Logistics segment.

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

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities, (ii) borrowings under our credit facilities or commercial paper program and (iii) funds received from sales of equity and debt securities. Our primary cash requirements include, but are not limited to, (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products and other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under our commercial paper program or credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing our long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional equity or debt securities. As of March 31, 2016, we had a working capital deficit of $283 million and over $3.8 billion of liquidity available to meet our ongoing operating, investing and financing needs, subject to continued covenant compliance, as noted below (in millions):

		As of March 31, 2016
Availability under senior unsecured revolving credit facility (1) (2)	$	1,584

Availability under senior secured hedged inventory facility (1) (2)		1,371
Availability under senior unsecured 364-day revolving credit facility		1,000
Amounts outstanding under commercial paper program		(160)
Subtotal		3,795
Cash and cash equivalents		36
Total	$	3,831

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

(2) Available capacity under the senior unsecured revolving credit facility and the senior secured hedged inventory facility was reduced by outstanding letters of credit of $16 million and $29 million, respectively.

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We believe that we have, and will continue to have, the ability to access the commercial paper program and credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A. Risk Factors of our 2015 Annual Report on Form 10-K for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities, which provide the backstop for the commercial paper program, is subject to ongoing compliance with covenants. As of March 31, 2016, we were in compliance with all such covenants.

Cash Flow from Operating Activities

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

Net cash provided by operating activities for the first three months of 2016 and 2015 was $635 million and $732 million, respectively, and primarily resulted from earnings from our operations. Additionally, as discussed further below, changes in our inventory levels during these periods impacted our cash flow from operating activities.

During each of the three months ended March 31, 2016 and 2015, we decreased the overall volume of inventory that we held, primarily due to the seasonal sale of NGL and natural gas inventory. The net proceeds received from liquidation of such inventory were used to repay borrowings under our commercial paper program and favorably impacted cash flow from operating activities during each period. Additionally, lower inventory levels were further impacted by lower prices for such inventory stored at the end of each quarter compared to the prior year end. However, the favorable effects from liquidation of our NGL and natural gas inventory were partially offset by increased levels of crude oil inventory purchased and stored due to contango market conditions.

Minimum Volume Commitments. We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Some of these agreements include make-up rights if the minimum volume is not met. At March 31, 2016, counterparty deficiencies associated with agreements that include minimum volume commitments totaled $53 million. We record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty s ability to utilize the make-up right is remote. Deferred revenue associated with non-performance under minimum volume contracts could be significant and could adversely affect our profitability and earnings, but generally does not impact our liquidity.

As of March 31, 2016, we had deferred revenue associated with minimum volume commitments of $45 million. In addition to the amounts recorded as deferred revenue, as of March 31, 2016, there was $8 million of accrued deficiencies for which the counterparties had not met their contractual minimum commitments, but we had not yet billed or collected such amounts.

Acquisitions, Capital Expenditures and Divestitures

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

Acquisitions and Divestitures. During the three months ended March 31, 2016 and 2015, we paid cash of $85 million and $64 million, respectively, for acquisitions. In addition, during the first quarter of 2016, we completed the sale of various non-core assets for consideration of approximately $250 million, and since the beginning of the second quarter of 2016 we completed an additional divestiture of non-core assets for approximately $100 million.

In addition, in early April 2016, we entered into a definitive agreement to acquire an integrated system of NGL assets in Western Canada for a cash purchase price of approximately $150 million, subject to customary closing adjustments. We expect this transaction to close during the second quarter of 2016, subject to regulatory approvals and the satisfaction of customary closing conditions.

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2016 Capital Projects. See Acquisitions and Capital Projects for detail of our projected capital expenditures for the year ending December 31, 2016. We expect the majority of funding for our remaining 2016 capital program will be provided by the proceeds from our January 2016 Series A preferred unit offering.

Equity and Debt Financing Activities

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

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). At March 31, 2016, we had approximately $2.0 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. We did not conduct any offerings under our Traditional Shelf or under our WKSI Shelf during the three months ended March 31, 2016.

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

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

After two years, the Series A preferred units are convertible at the purchasers option into common units on a one-for-one basis, subject to certain conditions, and are convertible at our option in certain circumstances after three years. See Note 7 to our Consolidated Financial Statements for additional information regarding the Series A preferred units.

Credit Agreements, Commercial Paper Program and Indentures. Our credit agreements (which impact our ability to access our commercial paper program because they provide the backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. As of March 31, 2016, we were in compliance with the covenants contained in our credit agreements and indentures.

During the three months ended March 31, 2016 and 2015, we had net repayments on our credit agreements and commercial paper program of $1.5 billion and $734 million, respectively. The net repayments during both periods resulted primarily from cash flow from operating activities, including sales of NGL and natural gas inventory that was liquidated during the periods, as well as cash received from our equity activities.

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

Distributions to Our Unitholders and General Partner

Distributions to our Series A preferred unitholders. On May 13, 2016, we will issue 858,439 Series A preferred units in lieu of paying a cash distribution of $23 million. Such distribution is prorated from the issuance date of the Series A preferred units.

Distributions to our common unitholders. We distribute 100% of our available cash within 45 days following the end of each quarter to common unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements.

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Our available cash also includes cash on hand resulting from borrowings made after the end of the quarter. On May 13, 2016, we will pay a quarterly distribution of $0.70 per common unit. See Note 7 to our Condensed Consolidated Financial Statements for details of distributions paid. Also, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Cash Distribution Policy included in our 2015 Annual Report on Form 10-K for additional discussion regarding distributions.

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

Contingencies

For a discussion of contingencies that may impact us, see Note 10 to our Condensed Consolidated Financial Statements.

Commitments

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

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of March 31, 2016 (in millions):

	Remainder of 2016	2017	2018	2019	2020	2021 and Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 554	$ 846	$ 1,020	$ 1,236	$ 834	$ 11,041	$ 15,531
Leases (2)	154	188	157	131	110	436	1,176

Other obligations (3)	626	385	195	173	148	601	2,128
Subtotal	1,334	1,419	1,372	1,540	1,092	12,078	18,835
Crude oil, natural gas, NGL and other purchases (4)	3,462	2,302	1,620	1,417	1,160	4,075	14,036
Total	$ 4,796	$ 3,721	$ 2,992	$ 2,957	$ 2,252	$ 16,153	$ 32,871

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

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

(3) Includes (i) other long-term liabilities (excluding approximately $99 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases), (ii) storage, processing and transportation agreements and (iii) non-cancelable commitments related to our capital expansion projects, including projected contributions for our share of the

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capital spending of our equity method investments. The transportation agreements include approximately $910 million associated with an agreement to transport crude oil on a pipeline that is owned by an equity method investee, in which we own a 50% interest. Our commitment to transport is supported by crude oil buy/sell agreements with third parties (including Oxy) with commensurate quantities.

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

Letters of Credit. In connection with supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs, derivative transactions and construction activities. At March 31, 2016 and December 31, 2015, we had outstanding letters of credit of approximately $45 million and $46 million, respectively.

Off-Balance Sheet Arrangements

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

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

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

FORWARD-LOOKING STATEMENTS

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

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

- the effects of competition;

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

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

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

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

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

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

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

- the currency exchange rate of the Canadian dollar;

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

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

- non-utilization of our assets and facilities;

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

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

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

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

- the effectiveness of our risk management activities;

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

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

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

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

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

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

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

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

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various market risks, including (i) commodity price risk, (ii) interest rate risk and (iii) currency exchange rate risk. We use various derivative instruments to manage such risks and, in certain circumstances, to realize incremental margin during volatile market conditions. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our exchange-cleared and over-the-counter positions, as well as physical volumes, grades, locations,

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delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

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

- *Crude oil*

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

- *Natural gas*

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

- *NGL and other*

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

See Note 8 to our Condensed Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

The fair value of our commodity derivatives and the change in fair value as of March 31, 2016 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil	$ 72	$ (65)	$ 65
Natural gas	(6)	$ (1)	$ 1
NGL and other	14	$ (12)	$ 12
Total fair value	$ 80		

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

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time, we use interest rate derivatives to hedge interest rate risk associated with anticipated interest payments and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus are not subject to interest rate risk. Our variable rate debt outstanding at March 31, 2016, approximately $160 million, was subject to interest rate re-sets of less than one week. The average interest rate on variable rate debt that was outstanding during the three months ended March 31, 2016 was 1.1%, based upon rates in effect during such period. The fair value of our interest rate derivatives was a liability of $138 million as of

March 31, 2016. A 10% increase in the forward LIBOR curve as of March 31, 2016 would have resulted in an increase of $42 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of March 31, 2016 would have resulted in a decrease of $42 million to the fair value of our interest rate derivatives. See Note 8 to our Condensed Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives was an asset of $5 million as of March 31, 2016. A 10% increase in the exchange rate (USD-to-CAD) would have resulted in a decrease of $19 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would have resulted in an increase of $19 million to the fair value of our foreign currency derivatives. See Note 8 to our Condensed Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

Preferred Distribution Rate Reset Option

The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value in our Condensed Consolidated Balance Sheets. The valuation model utilized for this embedded derivative contains inputs including our future common unit price, future ten-year U.S. treasury rates and future default probabilities to ultimately calculate the fair value of our Series A preferred units with and without the Preferred Distribution Rate Reset Option. The fair value of this embedded derivative was a liability of $60 million as of March 31, 2016. A 10% increase in the fair value would have an impact of $6 million. A 10% decrease in the fair value would also have an impact of $6 million. See Note 8 to our Condensed Consolidated Financial Statements for a discussion of embedded derivatives.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

Applicable SEC rules require an evaluation of the effectiveness of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our DCP as of March 31, 2016, the end of the period covered by this report, and, based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our DCP is effective.

Changes in Internal Control over Financial Reporting

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

Certifications

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

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included under the caption Legal Proceedings General in Note 10 to our Condensed Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

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

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

Information with respect to unregistered sales of equity securities during the three months ended March 31, 2016 was previously included in Current Reports on Form 8-K filed on January 19, 2016 and February 2, 2016.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. MINE SAFETY DISCLOSURES

None.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

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

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SIGNATURES

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

	PLAINS ALL AMERICAN PIPELINE, L.P.	
	By:	PAA GP LLC, *its general partner*
	By:	Plains AAP, L.P., *its sole member*
	By:	PLAINS ALL AMERICAN GP LLC, *its general partner*
	By:	/s/ Greg L. Armstrong **Greg L. Armstrong,** ***Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)***
May 9, 2016		
	By:	/s/ Al Swanson **Al Swanson,** ***Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)***
May 9, 2016		
	By:	/s/ Chris Herbold **Chris Herbold,** ***Vice President Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)***
May 9, 2016		

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EXHIBIT INDEX

3.1	Fifth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of January 28, 2016 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed February 2, 2016).
3.2	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.4	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.5	Amendment No. 3 dated June 30, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.7 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.6	Amendment No. 4 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P (incorporated by reference to Exhibit 3.8 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.7	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.8	Amendment No. 1 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.9	Sixth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated October 21, 2013 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed October 25, 2013).
3.10	Amendment No. 1 dated January 28, 2016 to the Sixth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed February 2, 2016).
3.11	Seventh Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated October 21, 2013 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 25, 2013).
3.12	Amendment No. 1 dated December 31, 2013 to the Seventh Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed December 31, 2013).
3.13	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2006).
3.14	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to our Annual Report on Form 10-K for the year ended December 31, 2006).
3.15	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed January 4, 2008).

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4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to our Registration Statement on Form S-4, File No. 333-121168).
4.3	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed May 12, 2006).
4.4	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed October 30, 2006).
4.5	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed October 30, 2006).
4.6	Thirteenth Supplemental Indenture (Series A and Series B 6.50% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 23, 2008).
4.7	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 20, 2009).
4.8	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 4, 2009).
4.9	Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed January 11, 2011).
4.10	Twentieth Supplemental Indenture (3.65% Senior Notes due 2022) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed March 26, 2012).
4.11	Twenty-First Supplemental Indenture (5.15% Senior Notes due 2042) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed March 26, 2012).
4.12	Twenty-Second Supplemental Indenture (2.85% Senior Notes due 2023) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed December 12, 2012).
4.13	Twenty-Third Supplemental Indenture (4.30% Senior Notes due 2043) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 12, 2012).

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4.14	Twenty-Fourth Supplemental Indenture (3.85% Senior Notes due 2023) dated August 15, 2013, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 15, 2013).
4.15	Twenty-Fifth Supplemental Indenture (4.70% Senior Notes due 2044) dated April 23, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 29, 2014).
4.16	Twenty-Sixth Supplemental Indenture (3.60% Senior Notes due 2024) dated September 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 11, 2014).
4.17	Twenty-Seventh Supplemental Indenture (2.60% Senior Notes due 2019) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed December 11, 2014).
4.18	Twenty-Eighth Supplemental Indenture (4.90% Senior Notes due 2045) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 11, 2014).
4.19	Twenty-Ninth Supplemental Indenture (4.65% Senior Notes due 2025) dated August 24, 2015, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 26, 2015).
4.20	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to our Registration Statement on Form S-3, File No. 333-162477).
4.21	Registration Rights Agreement dated as of January 28, 2016 among Plains All American Pipeline, L.P. and the Purchasers named therein (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed February 2, 2016).
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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Filed herewith.

Furnished herewith.