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, 2015

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 1, 2015, there were 397,241,697 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, 2015	December 31, 2014
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 458	$ 403
Trade accounts receivable and other receivables, net	1,817	2,615
Inventory	929	891
Other current assets	249	270
Total current assets	3,453	4,179
PROPERTY AND EQUIPMENT	14,436	14,178
Accumulated depreciation	(1,952)	(1,906)
Property and equipment, net	12,484	12,272
OTHER ASSETS		
Goodwill	2,435	2,465
Investments in unconsolidated entities	1,784	1,735
Linefill and base gas	960	930
Long-term inventory	149	186
Other long-term assets, net	459	489
Total assets	$ 21,724	$ 22,256
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,491	$ 2,986
Short-term debt	553	1,287
Other current liabilities	487	482
Total current liabilities	3,531	4,755
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $17 and $18, respectively	8,758	8,757
Other long-term debt	5	5
Other long-term liabilities and deferred credits	594	548
Total long-term liabilities	9,357	9,310
COMMITMENTS AND CONTINGENCIES (NOTE 10)		

PARTNERS CAPITAL				
Common unitholders (397,241,697 and 375,107,793 units outstanding, respectively)		8,413		7,793
General partner		365		340
Total partners capital excluding noncontrolling interests		8,778		8,133
Noncontrolling interests		58		58
Total partners capital		8,836		8,191
Total liabilities and partners capital	$	21,724	$	22,256

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
	(unaudited)	
REVENUES		
Supply and Logistics segment revenues	$ 5,632	$ 11,346
Transportation segment revenues	185	181
Facilities segment revenues	125	157
Total revenues	5,942	11,684
COSTS AND EXPENSES		
Purchases and related costs	5,042	10,670
Field operating costs	346	336
General and administrative expenses	78	89
Depreciation and amortization	107	96
Total costs and expenses	5,573	11,191
OPERATING INCOME	369	493
OTHER INCOME/(EXPENSE)		
Equity earnings in unconsolidated entities	37	20
Interest expense (net of capitalized interest of $14 and $11, respectively)	(102)	(78)
Other expense, net	(4)	(2)
INCOME BEFORE TAX	300	433
Current income tax expense	(42)	(36)
Deferred income tax benefit/(expense)	26	(12)
NET INCOME	284	385
Net income attributable to noncontrolling interests	(1)	(1)
NET INCOME ATTRIBUTABLE TO PAA	$ 283	$ 384
NET INCOME ATTRIBUTABLE TO PAA:		
LIMITED PARTNERS	$ 138	$ 268
GENERAL PARTNER	$ 145	$ 116
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.36	$ 0.74
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.35	$ 0.73
BASIC WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING	383	360
DILUTED WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING	385	363

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME / (LOSS)

(in millions)

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
	(unaudited)	
Net income	$ 284	$ 385
Other comprehensive loss	(376)	(136)
Comprehensive income/(loss)	(92)	249
Comprehensive income attributable to noncontrolling interests	(1)	(1)
Comprehensive income/(loss) attributable to PAA	$ (93)	$ 248

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, 2014	$ (159)	$ (308)	$ (467)
Reclassification adjustments	(6)		(6)
Deferred loss on cash flow hedges, net of tax	(72)		(72)
Currency translation adjustments		(298)	(298)
Total period activity	(78)	(298)	(376)
Balance at March 31, 2015	$ (237)	$ (606)	$ (843)

	Derivative Instruments	Translation Adjustments (unaudited)	Total
Balance at December 31, 2013	$ (77)	$ (20)	$ (97)
Reclassification adjustments	20		20
Deferred loss on cash flow hedges, net of tax	(32)		(32)
Currency translation adjustments		(124)	(124)
Total period activity	(12)	(124)	(136)

Balance at March 31, 2014	$	(89)	$	(144)	$	(233)

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, 2015	Three Months Ended March 31, 2014
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 284	$ 385
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	107	96
Equity-indexed compensation expense	19	34
Inventory valuation adjustments	24	37
Deferred income tax (benefit)/expense	(26)	12
(Gain)/loss on foreign currency revaluation	(27)	5
Equity earnings in unconsolidated entities	(37)	(20)
Distributions from unconsolidated entities	54	25
Other	(9)	(6)
Changes in assets and liabilities, net of acquisitions	343	254
Net cash provided by operating activities	732	822
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(64)	
Additions to property, equipment and other	(441)	(468)
Investment in unconsolidated entities	(65)	(26)
Cash received for sales of linefill and base gas		11
Cash paid for purchases of linefill and base gas	(96)	(44)
Proceeds from sales of assets	1	2
Other investing activities	(1)	1
Net cash used in investing activities	(666)	(524)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments under commercial paper program (Note 6)	(734)	(128)
Net proceeds from the issuance of common units (Note 7)	1,099	148
Contributions from general partner	22	3
Distributions paid to common unitholders (Note 7)	(254)	(221)
Distributions paid to general partner (Note 7)	(136)	(107)
Distributions paid to noncontrolling interests	(1)	(1)
Other financing activities	(2)	(1)
Net cash used in financing activities	(6)	(307)
Effect of translation adjustment on cash	(5)	(2)
Net increase/(decrease) in cash and cash equivalents	55	(11)
Cash and cash equivalents, beginning of period	403	41
Cash and cash equivalents, end of period	$ 458	$ 30
Cash paid for:		
Interest, net of amounts capitalized	$ 74	$ 78
Income taxes, net of amounts refunded	$ 11	$ 66

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS CAPITAL

(in millions)

	Common Units Units	Common Units Amount	General Partner	Partners Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners Capital
			(unaudited)			
Balance at December 31, 2014	375.1	$ 7,793	$ 340	$ 8,133	$ 58	$ 8,191
Net income		138	145	283	1	284
Distributions		(254)	(136)	(390)	(1)	(391)
Issuance of common units	22.1	1,099	22	1,121		1,121
Equity-indexed compensation expense		8	1	9		9
Distribution equivalent right payments		(2)		(2)		(2)
Other comprehensive loss		(369)	(7)	(376)		(376)
Balance at March 31, 2015	397.2	$ 8,413	$ 365	$ 8,778	$ 58	$ 8,836

	Common Units Units	Common Units Amount	General Partner	Partners Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners Capital
			(unaudited)			
Balance at December 31, 2013	359.1	$ 7,349	$ 295	$ 7,644	$ 59	$ 7,703
Net income		268	116	384	1	385
Distributions		(221)	(107)	(328)	(1)	(329)
Issuance of common units	2.8	148	3	151		151
Issuance of common units under LTIP, net of units tendered by employees to satisfy tax withholding obligations	0.1	(2)		(2)		(2)
Equity-indexed compensation expense		11	1	12		12
Distribution equivalent right payments		(1)		(1)		(1)
Other comprehensive loss		(133)	(3)	(136)		(136)
Balance at March 31, 2014	362.0	$ 7,419	$ 305	$ 7,724	$ 59	$ 7,783

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. 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, Plains, PAA, we, us, our, ours and similar terms refer to Plains All American Pipeline, L.P. 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, 2015, owned an approximate 37% limited partner interest in AAP.

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

Definitions

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

AOCI	=	Accumulated other comprehensive income / (loss)

Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
DERs	=	Distribution equivalent rights
EPA	=	United States Environmental Protection Agency
FASB	=	Financial Accounting Standards Board
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	Intercontinental Exchange
LIBOR	=	London Interbank Offered Rate
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MLP	=	Master limited partnership
NGL	=	Natural gas liquids, including ethane, propane and butane
NYMEX	=	New York Mercantile Exchange
Oxy	=	Occidental Petroleum Corporation or its subsidiaries
PLA	=	Pipeline loss allowance
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 2014 Annual Report on Form 10-K. The accompanying consolidated financial statements include the accounts of PAA and all of its wholly owned subsidiaries and those entities that it controls. Investments in entities over which we have significant influence but not control are accounted for by the equity method. The financial statements have been prepared in accordance with the instructions for interim reporting as set forth by the SEC. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income attributable to PAA. The condensed consolidated balance sheet data as of December 31, 2014 was derived from audited financial statements, but does not include all disclosures required by GAAP. The results of operations for the three months ended March 31, 2015 should not be taken as indicative of results to be expected for the entire year.

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

Note 2 Recent Accounting Pronouncements

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

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

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

In May 2014, the FASB issued guidance regarding the recognition of revenue from contracts with customers with the underlying principle that an entity will recognize revenue to reflect amounts expected to be received in exchange for the provision of goods and services to customers upon the transfer of those goods or services. The guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. This guidance becomes effective for interim and annual periods beginning after December 15, 2016 and can be adopted either with a full retrospective approach or a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. We currently expect to adopt this guidance on January 1, 2017, and we are evaluating which transition approach to apply and the effect that adopting this guidance will have on our financial position, results of operations and cash flows. In April 2015, the FASB proposed a one year deferral of the effective date of this standard.

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

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Note 3 Net Income Per Limited Partner Unit

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

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

Diluted net income per limited partner unit is computed based on the weighted average number of limited partner units plus the effect of dilutive potential limited partner units outstanding during the period using the two-class method. Our LTIP awards that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical limited partner unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. See Note 16 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for a complete discussion of our LTIP awards including specific discussion regarding DERs.

The following table sets forth the computation of basic and diluted net income per limited partner unit for the three months ended March 31, 2015 and 2014 (in millions, except per unit data):

	Three Months Ended March 31,			
		2015		2014
Basic Net Income per Limited Partner Unit				
Net income attributable to PAA	$	283	$	384
Less: General partner s incentive distribution (1)		(142)		(110)
Less: General partner 2% ownership (1)		(3)		(6)
Net income available to limited partners		138		268
Less: Undistributed earnings allocated and distributions to participating securities (1)		(2)		(2)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$	136	$	266
Basic weighted average limited partner units outstanding		383		360
Basic net income per limited partner unit	$	0.36	$	0.74
Diluted Net Income per Limited Partner Unit				
Net income attributable to PAA	$	283	$	384
Less: General partner s incentive distribution (1)		(142)		(110)

Less: General partner 2% ownership (1)		(3)		(6)
Net income available to limited partners		138		268
Less: Undistributed earnings allocated and distributions to participating securities (1)		(2)		(2)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$	136	$	266
Basic weighted average limited partner units outstanding		383		360
Effect of dilutive securities: Weighted average LTIP units		2		3
Diluted weighted average limited partner units outstanding		385		363
Diluted net income per limited partner unit	$	0.35	$	0.73

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

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

	Three Months Ended March 31,			
	2015		2014	
Basic net income per limited partner unit impact	$		$	(0.05)
Diluted net income per limited partner unit impact	$		$	(0.05)

Note 4 Accounts Receivable

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

To mitigate credit risk related to our accounts receivable, we utilize a rigorous credit review process. We closely monitor market conditions to make a determination with respect to the amount, if any, of open credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of advance cash payments, standby letters of credit or parental guarantees. As of March 31, 2015 and December 31, 2014, we had received $130 million and $180 million, respectively, of advance cash payments from third parties to mitigate credit risk. Furthermore, as of March 31, 2015 and December 31, 2014, we had received $12 million and $198 million, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. The decrease in standby letters of credit and advance cash payments from third parties as of March 31, 2015 compared to December 31, 2014 is largely due to a decrease in exposure to various customers requiring letters of credit. Furthermore, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. Further, we 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, 2015 and December 31, 2014, substantially all of our accounts receivable (net of allowance for doubtful accounts) were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $4 million as of both March 31, 2015 and December 31, 2014. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

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

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

	March 31, 2015				December 31, 2014			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)
Inventory								
Crude oil	15,351	barrels	$ 686	$ 44.69	6,465	barrels	$ 304	$ 47.02
NGL	7,277	barrels	154	$ 21.16	13,553	barrels	454	$ 33.50
Natural gas	10,965	Mcf	31	$ 2.83	32,317	Mcf	102	$ 3.16
Other	N/A		58	N/A	N/A		31	N/A
Inventory subtotal			929				891	
Linefill and base gas								
Crude oil	12,970	barrels	777	$ 59.91	11,810	barrels	744	$ 63.00
NGL	1,215	barrels	48	$ 39.51	1,212	barrels	52	$ 42.90
Natural gas	28,612	Mcf	135	$ 4.72	28,612	Mcf	134	$ 4.68
Linefill and base gas subtotal			960				930	
Long-term inventory								
Crude oil	2,646	barrels	117	$ 44.22	2,582	barrels	136	$ 52.67
NGL	1,681	barrels	32	$ 19.04	1,681	barrels	50	$ 29.74
Long-term inventory subtotal			149				186	
Total			$ 2,038				$ 2,007	

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

At the end of each reporting period, we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. Any resulting adjustments are a component of Purchases and related costs on our accompanying Condensed Consolidated Statements of Operations. We recorded a charge of $24 million during the 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 for which the related derivatives were still open as of March 31, 2015. See Note 8 for discussion of our derivative and risk management activities. During the three months ended March 31, 2014, we recorded a charge of $37 million related to the writedown of our natural gas inventory that was purchased in conjunction with managing natural gas storage deliverability requirements during the extended period of severe cold weather in the first quarter of 2014.

Note 6 Debt

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

	March 31, 2015	December 31, 2014
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 0.46% at December 31, 2014 (1)	$	$ 734
Senior notes:		
5.25% senior notes due June 2015	150	150
3.95% senior notes due September 2015	400	400
Other	3	3
Total short-term debt	553	1,287
LONG-TERM DEBT		
Senior notes, net of unamortized discount of $17 and $18, respectively	8,758	8,757
Other	5	5
Total long-term debt	8,763	8,762
Total debt (2)	$ 9,316	$ 10,049

(1) At December 31, 2014, we classified all of the borrowings under our commercial paper program as short-term as these borrowings were primarily designated as working capital borrowings, must 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 $9.3 billion as of both March 31, 2015 and December 31, 2014. We estimated the aggregate fair value of these notes as of March 31, 2015 and December 31, 2014 to be approximately $10.0 billion and $9.9 billion, respectively. Our fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near quarter end. We estimate that the carrying value of outstanding borrowings under our credit facilities and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities and commercial paper program are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

Credit Facilities

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

Borrowings and Repayments

Total borrowings under our credit agreements and commercial paper program for the three months ended March 31, 2015 and 2014 were approximately $7.0 billion and $19.2 billion, respectively. Total repayments under our credit agreements and commercial paper program were approximately $7.7 billion and $19.3 billion for the three months ended March 31, 2015 and 2014, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

Letters of Credit

In connection with our supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs and construction activities. At March 31, 2015 and December 31, 2014, we had outstanding letters of credit of $83 million and $87 million, respectively.

Note 7 Partners Capital and Distributions

Distributions

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

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

(1) Payable to unitholders of record at the close of business on May 1, 2015 for the period January 1, 2015 through March 31, 2015.

PAA Equity Offerings

Continuous Offering Program. During the three months ended March 31, 2015, we issued an aggregate of approximately 1.1 million common units under our continuous offering program, generating proceeds of $59 million, including our general partner s proportionate capital contribution of $1 million, net of $1 million of commissions to our sales agents.

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

Noncontrolling Interests in Subsidiaries

As of March 31, 2015, 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 on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items.

Commodity Price Risk Hedging

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

Commodity Purchases and Sales In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of March 31, 2015, net derivative positions related to these activities included:

- An average of 233,600 barrels per day net long position (total of 7.0 million barrels) associated with our crude oil purchases, which was unwound ratably during April 2015 to match monthly average pricing.

- A net short time spread position averaging 18,200 barrels per day (total of 7.2 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through June 2016.

- An average of 37,500 barrels per day (total of 9.1 million barrels) of crude oil grade spread positions through December 2015. These derivatives allow us to lock in grade basis differentials.

- A net short position of 6.8 Bcf through April 2016 related to anticipated sales of natural gas inventory and base gas requirements.

- A net short position of 16.8 million barrels through March 2017 related to anticipated purchases and sales of our crude oil, NGL and refined products inventory.

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, 2015, we had a long natural gas position of 18.1 Bcf through December 2016, a short propane position of 3.5 million barrels through December 2016, a short butane position of 1.0 million barrels through December 2016 and a short WTI position of 0.4 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 natural gas processing and fractionation plants through December 2016.

To the extent they qualify and we decide to make the election, all of our commodity derivatives for which we elect hedge accounting are designated as cash flow hedges. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the normal purchases and normal sales scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchases and normal sales scope exception.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of March 31, 2015, AOCI includes deferred losses of $234 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 debt issuances through 2019. The following table summarizes the terms of our forward starting interest rate swaps as of March 31, 2015 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated debt offering	10 forward starting swaps (30-year)	$ 250	6/15/2015	3.60%	Cash flow hedge
Anticipated debt offering	8 forward starting swaps (30-year)	$ 200	6/15/2016	3.06%	Cash flow hedge
Anticipated debt offering	8 forward starting swaps (30-year)	$ 200	6/15/2017	3.14%	Cash flow hedge
Anticipated debt offering	8 forward starting swaps (30-year)	$ 200	6/15/2018	3.20%	Cash flow hedge
Anticipated debt offering	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, 2015, our outstanding foreign currency derivatives include derivatives we use to (i) hedge currency exchange risk associated with USD-denominated commodity purchases and sales in Canada and (ii) hedge currency exchange risk created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

The following table summarizes our open forward exchange contracts as of March 31, 2015 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2015	$ 147	$ 187	$1.00 - $1.27
	2016	5	7	$1.00 - $1.27
		$ 152	$ 194	
Forward exchange contracts that exchange USD for CAD:				
	2015	$ 181	$ 225	$1.00 - $1.24
	2016	5	7	$1.00 - $1.27
		$ 186	$ 232	

Summary of Financial Impact

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

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A summary of the impact of our derivative activities recognized in earnings for the three months ended March 31, 2015 and 2014 is as follows (in millions):

	Three Months Ended March 31, 2015			Three Months Ended March 31, 2014		
Location of gain/(loss)	**Derivatives in Hedging Relationships (1)**	**Derivatives Not Designated as a Hedge**	**Total**	**Derivatives in Hedging Relationships (1)**	**Derivatives Not Designated as a Hedge**	**Total**
Commodity Derivatives						
Supply and Logistics segment revenues	$ 7	$ (34)	$ (27)	$ (19)	$	$ (19)
Transportation segment revenues		2	2			
Field operating costs		(4)	(4)		(1)	(1)
Interest Rate Derivatives						
Interest expense	(1)		(1)	(1)		(1)
Foreign Currency Derivatives						
Supply and Logistics segment revenues		(17)	(17)		(9)	(9)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 6	$ (53)	$ (47)	$ (20)	$ (10)	$ (30)

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

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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, 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	$	18	Other long-term liabilities and deferred credits	$	(2)
	Other long-term liabilities and deferred credits		3			
Interest rate derivatives				Other current liabilities		(64)
				Other long-term liabilities and deferred credits		(80)
Total derivatives designated as hedging instruments		$	21		$	(146)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	205	Other current assets	$	(47)
	Other long-term assets, net		18	Other current liabilities		(40)
	Other long-term liabilities and deferred credits		2	Other long-term liabilities and deferred credits		(13)
Foreign currency derivatives				Other current liabilities		(4)
Total derivatives not designated as hedging instruments		$	225		$	(104)
Total derivatives		$	246		$	(250)

The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheet on a gross basis as of December 31, 2014 (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	$	23	Other current assets	$	(12)
	Other long-term assets, net		8	Other long-term assets, net		(1)
Interest rate derivatives				Other current liabilities		(44)
						(26)

				Other long-term liabilities and deferred credits		
Total derivatives designated as hedging instruments		$	31		$	(83)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	439	Other current assets	$	(246)
	Other long-term assets, net		23	Other long-term assets, net		(3)
				Other current liabilities		(35)
				Other long-term liabilities and deferred credits		(5)
Foreign currency derivatives				Other current liabilities		(12)
Total derivatives not designated as hedging instruments		$	462		$	(301)
Total derivatives		$	493		$	(384)

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

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through clearing brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of March 31, 2015, we had a net broker payable of $112 million (consisting of initial margin of $61 million reduced by $173 million of variation margin that had been returned to us). As of December 31, 2014, we had a net broker payable of $133 million (consisting of initial margin of $126 million reduced by $259 million of variation margin that had been returned to us).

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

	March 31, 2015		December 31, 2014	
	Derivative Asset Positions	**Derivative Liability Positions**	**Derivative Asset Positions**	**Derivative Liability Positions**
Netting Adjustments:				
Gross position - asset/(liability)	$ 246	$ (250)	$ 493	$ (384)
Netting adjustment	(52)	52	(262)	262
Cash collateral paid/(received)	(112)		(133)	
Net position - asset/(liability)	$ 82	$ (198)	$ 98	$ (122)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 64	$ —	$ 71	$ —
Other long-term assets, net	18		27	
Other current liabilities		(108)		(91)
Other long-term liabilities and deferred credits		(90)		(31)
	$ 82	$ (198)	$ 98	$ (122)

As of March 31, 2015, there was a net loss of $237 million deferred in AOCI including tax effects. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transaction or (ii) interest expense accruals associated with underlying debt instruments. Of the total net loss deferred in AOCI at March 31, 2015, we expect to reclassify a net gain of $9 million to earnings in the next twelve months. The remaining deferred loss of $246 million is expected to be reclassified to earnings through 2049. A portion of these amounts are based on market prices as of March 31, 2015; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The net deferred gain/(loss), including tax effects, recognized in AOCI for derivatives for the three months ended March 31, 2015 and 2014 was as follows (in millions):

	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	
Commodity derivatives, net	$	3	$	(12)
Interest rate derivatives, net		(75)		(20)
Total	$	(72)	$	(32)

At March 31, 2015 and December 31, 2014, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings. Although we may be required to post margin on our cleared derivatives as described above, we do not require our non-cleared derivative counterparties to post collateral with us.

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Recurring Fair Value Measurements

Derivative Financial Assets and Liabilities

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2015 and December 31, 2014 (in millions):

	Fair Value as of March 31, 2015				Fair Value as of December 31, 2014			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 16	$ 123	$ 5	$ 144	$ (85)	$ 261	$ 15	$ 191
Interest rate derivatives		(144)		(144)		(70)		(70)
Foreign currency derivatives		(4)		(4)		(12)		(12)
Total net derivative asset/(liability)	$ 16	$ (25)	$ 5	$ (4)	$ (85)	$ 179	$ 15	$ 109

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

Level 1

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

Level 2

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

Level 3

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

Rollforward of Level 3 Net Asset/(Liability)

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives classified as Level 3 for the three months ended March 31, 2015 and 2014 (in millions):

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
Beginning Balance	$ 15	$ (3)
Total gains/(losses) for the period:		
Settlements	(12)	3
Derivatives entered into during the period	2	1
Ending Balance	$ 5	$ 1
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	$ 2	$ 1

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Note 9 Equity-Indexed Compensation Plans

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

PAA LTIP Awards

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

	Units (1)		Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2014	7.3	$	41.45
Granted	1.1	$	39.99
Vested (2)		$	40.23
Cancelled or forfeited	(0.1)	$	39.69
Outstanding at March 31, 2015	8.3	$	41.26

(1) Amounts do not include AAP Management Units.

(2) During the three months ended March 31, 2015, less than 0.1 million PAA LTIP awards were settled in cash.

AAP Management Units

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

	Reserved for Future Grants	Outstanding	Outstanding Units Earned		Grant Date Fair Value of Outstanding AAP Management Units (1)
Balance at December 31, 2014	3.0	49.1	47.8	$	64
Earned	N/A	N/A	0.3		N/A
Balance at March 31, 2015	3.0	49.1	48.1	$	64

(1) Of the $64 million grant date fair value, $56 million had been recognized through March 31, 2015 on a cumulative basis. Of this amount, $1 million was recognized as expense during the three months ended March 31, 2015.

Other Consolidated Equity-Indexed Compensation Plan Information

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

	Three Months Ended March 31, 2015		2014	
Equity-indexed compensation expense	$	19	$	34
LTIP unit-settled vestings	$		$	5
LTIP cash-settled vestings (1)	$		$	1
DER cash payments	$	2	$	2

(1) For the three months ended March 31, 2015, the value of PAA LTIP awards that were settled in cash was less than $1 million.

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Note 10 Commitments and Contingencies

Litigation

In the ordinary course of business, we are involved in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, 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 the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows. Although we believe that our operations are presently in material compliance with applicable requirements, as we acquire and incorporate additional assets it is possible that the EPA or other governmental entities may seek to impose fines, penalties or performance obligations on us (or on a portion of our operations) as a result of any past noncompliance whether such noncompliance initially developed before or after our acquisition.

Environmental

General. Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline, rail and storage operations. These releases can result from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

At March 31, 2015, our estimated undiscounted reserve for environmental liabilities totaled $75 million, of which $11 million was classified as short-term and $64 million was classified as long-term. At December 31, 2014, our estimated undiscounted reserve for environmental liabilities totaled $82 million, of which $13 million was classified as short-term and $69 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in Accounts payable and accrued liabilities and Other long-term liabilities and deferred credits, respectively, on our Condensed Consolidated Balance Sheets. At March 31, 2015 and December 31, 2014, we had recorded receivables totaling $7 million and $8 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, which are predominantly reflected in Trade accounts receivable and other receivables, net on our Condensed Consolidated Balance Sheets.

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

Bay Springs Pipeline Release. During February 2013, we experienced a crude oil release of approximately 120 barrels on a portion of one of our pipelines near Bay Springs, Mississippi. Most of the released crude oil was contained within our pipeline right of way, but some of the released crude oil entered a nearby waterway where it was contained with booms. The EPA has issued an administrative order requiring us to take various actions in response to the release, including remediation, reporting and other actions. We have satisfied the requirements of the administrative order; however, we may be subjected to a civil penalty. The aggregate cost to clean up and remediate the site was $6 million.

Kemp River Pipeline Releases. During May and June 2013, two separate releases were discovered on our Kemp River pipeline in Northern Alberta, Canada that, in the aggregate, resulted in the release of approximately 700 barrels of condensate and light crude oil. Clean-up and remediation activities are being conducted in cooperation with the applicable regulatory agencies. Final investigation by the Alberta Energy Regulator is not complete. To date, no charges, fines or penalties have been assessed against PMC with respect to these releases; however, it is possible that fines or penalties may be assessed against PMC in the future. We estimate that the aggregate clean-up and remediation costs associated with these releases will be $15 million. Through March 31, 2015, we spent $9 million in connection with clean-up and remediation activities.

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

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 PAA s Bakersfield Crude Terminal LLC 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.

Note 11 Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on measures including segment profit and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses. Each of the items above excludes depreciation and amortization. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets.

The following table reflects certain financial data for each segment for the periods indicated (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Three Months Ended March 31, 2015				
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

	Transportation	Facilities	Supply and Logistics	Total
Three Months Ended March 31, 2014				
Revenues:				
External Customers	$ 181	$ 157	$ 11,346	$ 11,684

Intersegment (1)		206		142		22		370
Total revenues of reportable segments	$	387	$	299	$	11,368	$	12,054
Equity earnings in unconsolidated entities	$	20	$		$		$	20
Segment profit (2) (3)	$	206	$	154	$	249	$	609
Maintenance capital	$	34	$	10	$	2	$	46

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

(2) Supply and Logistics segment profit includes interest expense (related to hedged inventory purchases) of $1 million and $2 million for the three months ended March 31, 2015 and 2014, 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, 2015	Three Months Ended March 31, 2014
Segment profit	$ 513	$ 609
Depreciation and amortization	(107)	(96)
Interest expense, net	(102)	(78)
Other expense, net	(4)	(2)
Income before tax	300	433
Income tax expense	(16)	(48)
Net income	284	385
Net income attributable to noncontrolling interests	(1)	(1)
Net income attributable to PAA	$ 283	$ 384

Note 12 Related Party Transactions

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

Transactions with Oxy

As of March 31, 2015, Oxy owned approximately 13% of the limited partner interests in our general partner and had a representative on the board of directors of GP LLC. During the three months ended March 31, 2015 and 2014, we recognized sales and transportation revenues and purchased petroleum products from Oxy. These transactions were conducted at posted tariff rates or prices that we believe approximate market. See detail below (in millions):

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
Revenues	$ 176	$ 92
Purchases and related costs	$ 104	$ 259

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

	March 31, 2015	December 31, 2014
Trade accounts receivable and other receivables	$ 465	$ 489

Accounts payable	$	410	$	441

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical Consolidated Financial Statements and accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2014 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the Condensed Consolidated Financial Statements and related notes that are contained in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Our discussion and analysis includes the following:

- Executive Summary
- Acquisitions and Capital Projects
- Results of Operations
- 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 2015, we recognized net income attributable to PAA of $283 million as compared to net income attributable to PAA of $384 million recognized during the first three months of 2014. The decrease in operating results was due to less favorable results from our Supply and Logistics and Facilities segments partially offset by growth in our Transportation segment (see further discussion of our segment operating results in the following sections). Net income attributable to PAA for the first three months of 2015 was also impacted by:

- Higher depreciation and amortization expense and interest expense associated with our growing asset base and related financing activities; and

- Decreased income tax expense resulting from derivative mark-to-market losses in our Canadian operations.

We invested $586 million in midstream infrastructure projects during the three months ended March 31, 2015, with a targeted expansion capital plan for the full year of 2015 of $2.15 billion. To fund such capital activities, we issued approximately 22.1 million common units for net proceeds of approximately $1.1 billion during the first quarter. In addition, we paid $390 million of cash distributions to our limited partners and general partner during the three months ended March 31, 2015, and we declared a quarterly distribution of $0.6850 per limited partner unit to be paid on May 15, 2015.

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Acquisitions and Capital Projects

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

	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	
Acquisition capital	$	64	$	
Expansion capital (1)		586		563
Maintenance capital (1)		50		46
	$	700	$	609

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

2015 Capital Projects

Our capital program is highlighted by a large number of small-to-medium sized projects spread across multiple geographic regions/resource plays. We believe the diversity of our program mitigates the impact of delays, cost overruns or adverse market developments with respect to a particular project or geographic region/resource play. The majority of our 2015 expansion capital program will be invested in our fee-based Transportation and Facilities segments. We expect that our investments will have minimal contributions to our 2015 results, but will provide growth for 2016 and beyond. The following table summarizes our notable projects in progress during 2015 and the forecasted expenditures for the year ending December 31, 2015 (in millions):

Projects	2015
Permian Basin Area Projects	$390
Fort Saskatchewan Facility Projects / NGL Line	300
Rail Terminal Projects (1)	265
Cactus Pipeline (2)	135
Diamond Pipeline	130
Red River Pipeline (Cushing to Longview)	130
Saddlehorn Pipeline	100
Eagle Ford JV Project	90
Cowboy Pipeline (Cheyenne to Carr)	50
Eagle Ford Area Projects	45
Cushing Terminal Expansions	40
Line 63 Reactivation	25
Other Projects	450
	$2,150
Potential Adjustments for Timing / Scope Refinement (3)	-$50 + $100

Total Projected Expansion Capital Expenditures	$2,100 - $2,250
Maintenance Capital Expenditures	$205 - $225

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

(2) Includes linefill costs associated with the project.

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

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Results of Operations

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 19 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for further discussion of how we evaluate segment profit.

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	
	2015	**2014**	**$**	**%**
Transportation segment profit	$ 241	$ 206	$ 35	17%
Facilities segment profit	142	154	(12)	(8)%
Supply and Logistics segment profit	130	249	(119)	(48)%
Total segment profit	513	609	(96)	(16)%
Depreciation and amortization	(107)	(96)	(11)	(11)%
Interest expense, net	(102)	(78)	(24)	(31)%
Other expense, net	(4)	(2)	(2)	(100)%
Income tax expense	(16)	(48)	32	67%
Net income	284	385	(101)	(26)%
Net income attributable to noncontrolling interests	(1)	(1)		%
Net income attributable to PAA	$ 283	$ 384	$ (101)	(26)%
Net income attributable to PAA:				
Basic net income per limited partner unit	$ 0.36	$ 0.74	$ (0.38)	(51)%
Diluted net income per limited partner unit	$ 0.35	$ 0.73	$ (0.38)	(52)%
Basic weighted average limited partner units outstanding	383	360	23	6%
Diluted weighted average limited partner units outstanding	385	363	22	6%

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as non-GAAP financial measures in its evaluation of past performance and prospects for the future. The primary additional measures used by management are adjusted earnings before interest, taxes, depreciation and amortization (adjusted EBITDA) and implied distributable cash flow (DCF).

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and business outlook and/or (v) other items that we believe should be excluded in understanding our core operating performance. We have defined all such items hereinafter as Selected Items Impacting Comparability. These additional financial measures are reconciled to the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Condensed Consolidated Financial Statements and footnotes.

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,		Favorable/(Unfavorable) Variance	
	2018	2017	$	%
Net income	$ 284	$ 385	$ (101)	(26)%
Add:				
Interest expense, net	102	78	24	31%
Income tax expense	16	48	(32)	(67)%
Depreciation and amortization	107	96	11	11%
EBITDA	$ 509	$ 607	$ (98)	(16)%
Selected Items Impacting Comparability of EBITDA				
Gains/(losses) from derivative activities net of inventory valuation adjustments (1)	$ (91)	$ 65	$ (156)	(240)%
Long-term inventory costing adjustments (2)	(38)		(38)	N/A
Equity-indexed compensation expense (3)	(11)	(19)	8	42%
Net gain/(loss) on foreign currency revaluation (4)	27	(5)	32	640%
Other (5)		(1)	1	100%
Selected Items Impacting Comparability of EBITDA	$ (113)	$ 40	$ (153)	(383)%
EBITDA	$ 509	$ 607	$ (98)	(16)%
Selected Items Impacting Comparability of EBITDA	113	(40)	153	383%
Adjusted EBITDA	$ 622	$ 567	$ 55	10%
Adjusted EBITDA	$ 622	$ 567	$ 55	10%
Interest expense, net	(102)	(78)	(24)	(31)%
Maintenance capital (6)	(50)	(46)	(4)	(9)%
Current income tax expense	(42)	(36)	(6)	(17)%
Equity earnings in unconsolidated entities, net of distributions	17	5	12	240%
Distributions to noncontrolling interests (7)	(1)	(1)		%
Implied DCF	$ 444	$ 411	$ 33	8%
Less: Distributions paid (7)	(420)	(344)		
DCF Excess/(Shortage) (8)	$ 24	$ 67		

(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 4 million barrels of crude oil and NGL inventory that consists of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to Linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory that result from fluctuations in market prices and writedowns of such inventory

that result from price declines as a selected item impacting comparability. See Note 5 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for a complete discussion of our long-term inventory.

(3) Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability. See Note 16 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for a comprehensive discussion regarding our equity-indexed compensation plans.

(4) During the three months ended March 31, 2015 and 2014, there were fluctuations in the value of the Canadian dollar (CAD) to the U.S. dollar (USD), resulting in gains and losses that were not related to our core operating results for the period and were thus classified as selected items impacting comparability.

(5) Includes other immaterial selected items impacting comparability.

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

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

(8) Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes.

Analysis of Operating Segments

Transportation Segment

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

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

Operating Results (1)	Three Months Ended March 31,	Favorable/(Unfavorable) Variance

[redacted]

Revenues				
Tariff activities	$ 358	$ 336	$ 22	7%
Trucking	42	51	(9)	(18)%
Total transportation revenues	400	387	13	3%
Costs and Expenses				
Trucking costs	(30)	(37)	7	19%
Field operating costs (2)	(136)	(129)	(7)	(5)%
Equity-indexed compensation expense - operations	(3)	(4)	1	25%
Segment general and administrative expenses (2) (3)	(22)	(22)		%
Equity-indexed compensation expense - general and administrative	(5)	(9)	4	44%
Equity earnings in unconsolidated entities	37	20	17	85%
Segment profit	$ 241	$ 206	$ 35	17%
Maintenance capital	$ 33	$ 34	$ 1	3%
Segment profit per barrel	$ 0.63	$ 0.60	$ 0.03	5%

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Average Daily Volumes (in thousands of barrels per day) (4)	**Three Months Ended March 31, 2015**	**2014**	**Favorable/(Unfavorable) Variance Volumes**	**%**
Tariff activities				
Crude Oil Pipelines				
All American	36	33	3	9%
Bakken Area Systems (5)	152	131	21	16%
Basin / Mesa / Sunrise	821	745	76	10%
BridgeTex	83		83	N/A
Capline	153	126	27	21%
Eagle Ford Area Systems (5)	263	189	74	39%
Line 63 / Line 2000	136	125	11	9%
Manito	53	45	8	18%
Mid-Continent Area Systems	371	326	45	14%
Permian Basin Area Systems	754	760	(6)	(1)%
Rainbow	118	120	(2)	(2)%
Rangeland	62	69	(7)	(10)%
Salt Lake City Area Systems (5)	130	131	(1)	(1)%
South Saskatchewan	66	64	2	3%
White Cliffs	47	23	24	104%
Other	687	650	37	6%
NGL Pipelines				
Co-Ed	61	57	4	7%
Other	130	116	14	12%
Tariff activities total	4,123	3,710	413	11%
Trucking	121	130	(9)	(7)%
Transportation segment total	4,244	3,840	404	