PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
May 05, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) **May 5, 2015**

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**1-14569**	**76-0582150**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

Registrant s telephone number, including area code: **713-646-4100**

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press Release dated May 5, 2015

Item 2.02 and Item 7.01. Results of Operations and Financial Condition; Regulation FD Disclosure

Plains All American Pipeline, L.P. (the Partnership) today issued a press release reporting its first-quarter 2015 results. We are furnishing the press release, attached as Exhibit 99.1, pursuant to Item 2.02 and Item 7.01 of Form 8-K. Pursuant to Item 7.01, we are also providing detailed guidance for financial performance for the second quarter and full year of 2015. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under Item 2.02 and Item 7.01 shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Disclosure of Second-Quarter and Second-Half 2015 Guidance

We based our guidance for the three-month period ending June 30, 2015 and six-month period ending December 31, 2015 on assumptions and estimates that we believe are reasonable, given our assessment of historical trends (modified for changes in market conditions, including an assumption that crude oil prices do not meaningfully increase from current levels during 2015 which we expect to result in continued reduced drilling activity and reduced oil production growth as compared to 2014), business cycles and other reasonably available information. Projections covering multi-quarter periods contemplate inter-period changes in future performance resulting from new expansion projects, seasonal operational changes (such as NGL sales) and acquisition synergies. Our assumptions and future performance, however, are both subject to a wide range of business risks and uncertainties, so we can provide no assurance that actual performance will fall within the guidance ranges. Please refer to information under the caption Forward-Looking Statements and Associated Risks below. These risks and uncertainties, as well as other unforeseeable risks and uncertainties, could cause our actual results to differ materially from those in the following table. The operating and financial guidance provided below is given as of the date hereof, based on information known to us as of May 4, 2015. We undertake no obligation to publicly update or revise any forward-looking statements.

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as non-GAAP financial measures in its evaluation of past performance and prospects for the future. Management believes that the presentation of such additional financial measures provides useful information to investors regarding our financial condition and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operations 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. EBITDA (as defined below in Note 1 to the Operating and Financial Guidance table) is a non-GAAP financial measure. Net income represents one of the two most directly comparable GAAP measures to EBITDA. In Note 9 below, we reconcile net income to EBITDA and adjusted EBITDA for the 2015 guidance periods presented. Cash flows from operating activities is the other most comparable GAAP measure. We do not, however, reconcile cash flows from operating activities to EBITDA, because such reconciliations are impractical for forecasted periods. We encourage you to visit our website at *www.plainsallamerican.com* (in particular the section under Investor Relations and Financial Information entitled Non-GAAP Reconciliations), which presents a historical reconciliation of EBITDA as well as certain other commonly used non-GAAP financial measures. 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 as Selected Items Impacting Comparability. Due to the nature of the selected items, certain selected items impacting comparability may impact certain non-GAAP financial measures, referred to as adjusted results, but not impact other non-GAAP financial measures.

Plains All American Pipeline, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	Actual Three Months Ended Mar 31, 2015	Guidance (a) Three Months Ending Jun 30, 2015 Low	High	Six Months Ending Dec 31, 2015 Low	High	Twelve Months Ending Dec 31, 2015 Low	High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 937	$ 890	$ 930	$ 2,061	$ 2,141	$ 3,888	$ 4,008
Field operating costs	(346)	(381)	(374)	(731)	(716)	(1,458)	(1,436)
General and administrative expenses	(78)	(85)	(82)	(158)	(153)	(321)	(313)
	513	424	474	1,172	1,272	2,109	2,259
Depreciation and amortization expense	(107)	(113)	(109)	(221)	(213)	(441)	(429)
Interest expense, net	(102)	(106)	(102)	(215)	(207)	(423)	(411)
Income tax expense	(16)	(9)	(5)	(56)	(48)	(81)	(69)
Other expense, net	(4)					(4)	(4)
Net Income	**284**	**196**	**258**	**680**	**804**	**1,160**	**1,346**
Net income attributable to noncontrolling interests	(1)	(1)	(1)	(2)	(2)	(4)	(4)
Net Income Attributable to PAA	**$ 283**	**$ 195**	**$ 257**	**$ 678**	**$ 802**	**$ 1,156**	**$ 1,342**
Net Income to Limited Partners (b)	$ 138	$ 47	$ 108	$ 361	$ 482	$ 546	$ 728
Basic Net Income Per Limited Partner Unit (b)							
Weighted Average Units Outstanding	383	397	397	399	399	395	395
Net Income Per Unit	$ 0.36	$ 0.11	$ 0.27	$ 0.90	$ 1.21	$ 1.37	$ 1.84
Diluted Net Income Per Limited Partner Unit (b)							
Weighted Average Units Outstanding	385	400	400	401	401	397	397
Net Income Per Unit	$ 0.35	$ 0.11	$ 0.27	$ 0.90	$ 1.20	$ 1.36	$ 1.82
EBITDA	**$ 509**	**$ 424**	**$ 474**	**$ 1,172**	**$ 1,272**	**$ 2,105**	**$ 2,255**
Selected Items Impacting Comparability							
Gains/(losses) from derivative activities net of inventory valuation adjustments	$ (91)	$	$	$	$	$ (91)	$ (91)
Long-term inventory costing adjustments	(38)					(38)	(38)
Equity-indexed compensation expense	(11)	(11)	(11)	(21)	(21)	(43)	(43)
Net gain / (loss) on foreign currency revaluation	27					27	27
Tax effect on selected items impacting comparability	27					27	27
Selected Items Impacting Comparability of Net Income attributable to PAA	$ (86)	$ (11)	$ (11)	$ (21)	$ (21)	$ (118)	$ (118)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 246	$ 259	$ 269	$ 660	$ 680	$ 1,165	$ 1,195
Facilities	144	126	136	305	325	575	605
Supply and Logistics	231	50	80	228	288	509	599
Other income, net	1					1	1
Adjusted EBITDA	$ 622	$ 435	$ 485	$ 1,193	$ 1,293	$ 2,250	$ 2,400
Adjusted Net Income Attributable to PAA	$ 369	$ 206	$ 268	$ 699	$ 823	$ 1,274	$ 1,460

Basic Adjusted Net Income Per Limited Partner Unit (b)	$ 0.58	$ 0.14	$ 0.29	$ 0.95	$ 1.26	$ 1.67	$ 2.13
Diluted Adjusted Net Income Per Limited Partner Unit (b)	$ 0.57	$ 0.14	$ 0.29	$ 0.95	$ 1.25	$ 1.66	$ 2.11

(a) The assumed average foreign exchange rate is $1.25 Canadian dollar (CAD) to $1.00 U.S. dollar (USD) for the three-month period ending June 30, 2015 and the six-month period ending December 31, 2015. The rate as of May 4, 2015 was $1.21 CAD to $1.00 USD and the average for the three-month period ended on March 31, 2015 was $1.24 CAD to $1.00 USD. A $0.05 change in such average FX rate will impact the remaining nine months of 2015 adjusted EBITDA by approximately $6 million.

(b) 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.

Notes and Significant Assumptions:

1. *Definitions.*

EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Segment Profit	Net revenues (including equity earnings, as applicable) less field operating costs and segment general and administrative expenses
DCF	Distributable Cash Flow
Bbls/d	Barrels per day
Mcf	Thousand cubic feet
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
NGL	Natural gas liquids, including ethane and natural gasoline products as well as propane and butane, which are often referred to as liquefied petroleum gas (LPG). When used in this document, NGL refers to all NGL products including LPG.
FX	Foreign currency exchange
G&A	General and administrative
General partner (GP)	As the context requires, general partner or GP refers to any or all of (i) PAA GP LLC, the owner of our 2% general partner interest, (ii) Plains AAP, L.P., the sole member of PAA GP LLC and owner of our incentive distribution rights and (iii) Plains All American GP LLC, the general partner of Plains AAP, L.P.

2. *Operating Segments*. We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. The following is a brief explanation of the operating activities for each segment as well as key metrics.

a. *Transportation.* 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. Our transportation segment also includes our equity earnings from investments in the Eagle Ford, White Cliffs, BridgeTex, Butte and Frontier pipeline systems as well as Settoon Towing, in which we own interests ranging from 22% to 50%. We account for these investments under the equity method of accounting.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and assumed completion of capital projects. Actual volumes will be influenced by maintenance schedules at refineries, drilling and completion activity levels, production trends, weather and other natural occurrences including hurricanes, changes in the quantity of inventory held in tanks, variations due to market structure and other external factors beyond our control. We forecast adjusted segment profit using the volume assumptions in the table below, priced at forecasted tariff rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation. Actual segment profit could vary materially depending on the level and mix of volumes transported or expenses incurred during the period. The following table summarizes our total transportation volumes and highlights major systems that are significant either in total volumes transported or in contribution to total Transportation segment profit.

	Actual Three Months Ended Mar 31, 2015	Three Months Ending Jun 30, 2015	Guidance Six Months Ending Dec 31, 2015	Twelve Months Ending Dec 31, 2015
Average Daily Volumes (MBbls/d)				
Crude Oil Pipelines				
All American	36	35	40	38
Bakken Area Systems	152	150	155	153
Basin / Mesa / Sunrise	821	890	890	873
BridgeTex	83	120	120	111
Cactus		65	140	87
Capline	153	165	160	160
Eagle Ford Area Systems	263	295	360	320
Line 63 / 2000	136	125	140	135
Manito	53	50	50	51
Mid-Continent Area Systems	371	370	370	370
Permian Basin Area Systems	754	885	1,020	921
Rainbow	118	110	115	114
Rangeland	62	65	65	64
Salt Lake City Area Systems	130	130	145	138
South Saskatchewan	66	65	65	65
White Cliffs	47	50	55	52
Other	687	760	810	767
NGL Pipelines				
Co-Ed	61	60	60	60
Other	130	150	140	140
	4,123	4,540	4,900	4,619
Trucking	121	130	130	128
	4,244	4,670	5,030	4,747
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.64	$ 0.62(1)	$ 0.72(1)	$ 0.68(1)

(1) Represents the mid-point of guidance.

b. *Facilities*. Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. The Facilities segment generates revenue through a combination of month-to-month and multi-year agreements and processing arrangements.

Revenues generated in this segment primarily include (i) fees that are generated from storage capacity agreements, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and deliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) fees from NGL fractionation and isomerization, (v) fees from natural gas and condensate processing services and (vi) fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services. Adjusted segment profit is forecasted using the volume assumptions in the table below, priced at forecasted rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation.

		Actual Three Months Ended Mar 31, 2015		Three Months Ending Jun 30, 2015		Guidance Six Months Ending Dec 31, 2015		Twelve Months Ending Dec 31, 2015
Operating Data								
Crude Oil, Refined Products, and NGL Terminalling and Storage (MMBbls/Mo.)		99		99		101		100
Rail Load / Unload Volumes (MBbls/d)		206		240		350		287
Natural Gas Storage (Bcf/Mo.)		97		97		97		97
NGL Fractionation (MBbls/d)		102		100		115		108
Facilities Activities Total Avg. Capacity (MMBbls/Mo.) (1)		124		125		131		128
Segment Profit per Barrel ($/Bbl)								
Excluding Selected Items Impacting Comparability	$	0.39	$	0.35(2)	$	0.40(2)	$	0.38(2)

(1) 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.

(2) Represents the mid-point of guidance.

c. *Supply and Logistics*. Our Supply and Logistics segment operations generally consist of the following merchant-related activities:

- the purchase of U.S. and Canadian crude oil at the wellhead, the bulk purchase of crude oil at pipeline, terminal and rail facilities, and the purchase of cargos at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of NGL and natural gas;
- the purchase of NGL from producers, refiners, processors and other marketers;
- the resale or exchange of crude oil and NGL at various points along the distribution chain to refiners or other resellers;
- the transportation of crude oil and NGL on trucks, barges, railcars, pipelines and ocean-going vessels from various delivery points, market hub locations or directly to end users such as refineries, processors and fractionation facilities; and

- the purchase and sale of natural gas.

We characterize a substantial portion of our baseline profit generated by our Supply and Logistics segment as fee equivalent. This portion of the segment profit is generated by the purchase and resale of crude oil on an index-related basis, which results in us generating a gross margin for such activities. This gross margin is reduced by the transportation, facilities and other logistical costs associated with delivering the crude oil to market and carrying costs for hedged inventory as well as any operating and G&A expenses. The level of profit associated with a portion of the other activities we conduct in the Supply and Logistics segment is influenced by overall market structure and the degree of market volatility as well as variable operating expenses. Forecasted operating results for the three-month period ending June 30, 2015 reflect current market structure and for the six-month and twelve-month periods ending December 31, 2015 reflect the anticipated market structure as well as seasonal, and weather-related and other anticipated variations in crude oil, NGL and natural gas sales. Variations in weather, market structure or volatility could cause actual results to differ materially from forecasted results.

We forecast adjusted segment profit using the volume assumptions stated below, as well as estimates of unit margins, field operating costs, G&A expenses and carrying costs for hedged inventory, based on current and anticipated market conditions. Actual volumes are influenced by temporary market-driven storage and withdrawal of crude oil, maintenance schedules at refineries, actual production levels, weather, and other external factors beyond our control. Field operating costs do not include depreciation. Realized unit margins for any given lease-gathered barrel could vary significantly based on a variety of factors including location and quality differentials as well as contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	Actual	**Guidance**		
	Three Months Ended Mar 31, 2015	**Three Months Ending Jun 30, 2015**	**Six Months Ending Dec 31, 2015**	**Twelve Months Ending Dec 31, 2015**
Average Daily Volumes (MBbls/d)				
Crude Oil Lease Gathering Purchases	981	985	970	976
NGL Sales	286	150	220	219
	1,267	1,135	1,190	1,195
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 2.03	$ 0.63(1)	$ 1.18(1)	$ 1.27(1)

(1) Represents the mid-point of guidance.

3. *Depreciation and Amortization.* We forecast depreciation and amortization based on our existing depreciable assets, forecasted capital expenditures and projected in-service dates. Depreciation may also vary due to gains and losses on intermittent sales of assets, asset retirement obligations, asset impairments, acceleration of depreciation or foreign exchange rates.

4. *Capital Expenditures and Acquisitions.* Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any forecasts for acquisitions that we may commit to after the date hereof. We forecast capital expenditures during calendar year 2015 to be approximately $2.15 billion for expansion projects with an additional $205 to $225 million for maintenance capital projects. During the first three months of 2015, we spent $586 million and $50 million for expansion and maintenance projects, respectively. The following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2015:

	Calendar 2015 (in millions)
Expansion Capital	
• 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.

5. *Capital Structure.* This guidance is based on our capital structure as of March 31, 2015 and adjusted for estimated equity issuances and senior notes offerings to fund our capital program.

6. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, estimated capital expenditures for maintenance and expansion projects, anticipated equity proceeds from the continuous offering program, expected timing of collections and payments and forecasted levels of inventory and other working capital sources and uses. Interest rate assumptions for variable-rate debt are based on the LIBOR curve as of late April 2015.

Interest expense is net of amounts capitalized for expansion capital projects and does not include interest on borrowings for hedged inventory. We treat interest on hedged inventory borrowings as carrying costs of crude oil, NGL, and natural gas and include it in purchases and related costs. Interest expense includes an assumed fixed rate senior notes offering in 2015.

7. *Income Taxes*. We expect our Canadian income tax expense to be approximately $7 million and $75 million for the three-month period ending June 30, 2015 and twelve-month period ending December 31,2015, respectively, of which approximately $6 million and $92 million, respectively, is classified as a current income tax expense. For the twelve-month period ending December 31, 2015 we expect to have a deferred tax benefit of $17 million. All or part of the annual income tax expense of $75 million may result in a tax credit to our equity holders.

8. *Equity-Indexed Compensation Plans.* The majority of grants outstanding under our various equity-indexed compensation plans contain vesting criteria that are based on a combination of performance benchmarks and service periods. The grants will vest in various percentages, typically on the later to occur of specified vesting dates and the dates on which minimum distribution levels are reached. Among the various grants outstanding as of May 4, 2015, estimated vesting dates range from May 2015 to August 2019 and annualized benchmark distribution levels range from $2.075 to $3.20.

On April 7, 2015, we declared an annualized distribution of $2.74 payable on May 15, 2015 to our unitholders of record as of May 1, 2015. For the purposes of guidance, we have made the assessment that an annualized $2.90 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of $49 per unit as well as an accrual associated with awards that will vest on a certain date. The actual amount of equity-indexed compensation expense in any given period will be directly influenced by (i) our unit price at the end of each reporting period, (ii) our unit price on the vesting date, (iii) our then current probability assessment regarding distributions, and (iv) new equity-indexed compensation award grants, including the timing of such grant issuances. For example, a $2 change in the unit price would change the second-quarter equity-indexed compensation expense by approximately $5 million and the full year equity-indexed compensation expense by approximately $6 million. Therefore, actual net income could differ from our projections.

9. *Reconciliation of Net Income to EBITDA and Adjusted EBITDA.* The following table reconciles net income to EBITDA and Adjusted EBITDA for the indicated periods.

	Actual	Guidance					
	Three Months Ended	Three Months Ending Jun 30, 2015		Six Months Ending Dec 31, 2015		Twelve Months Ending Dec 31, 2015	
	Mar 31, 2015	Low	High	Low	High	Low	High
				(in millions)			

Reconciliation to EBITDA and Adjusted EBITDA							
Net Income	$ 284	$ 196	$ 258	$ 680	$ 804	$ 1,160	$ 1,346
Interest expense, net	102	106	102	215	207	423	411
Income tax expense	16	9	5	56	48	81	69
Depreciation and amortization	107	113	109	221	213	441	429
EBITDA	$ 509	$ 424	$ 474	$ 1,172	$ 1,272	$ 2,105	$ 2,255
Selected Items Impacting Comparability of EBITDA	113	11	11	21	21	145	145
Adjusted EBITDA	**$ 622**	**$ 435**	**$ 485**	**$ 1,193**	**$ 1,293**	**$ 2,250**	**$ 2,400**

10. *Implied DCF.* The following table reconciles adjusted EBITDA to implied DCF for the indicated periods.

	Actual Three Months Ended Mar 31, 2015	Three Months Ending Jun 30, 2015	Mid-Point Guidance Six Months Ending Dec 31, 2015	Twelve Months Ending Dec 31, 2015
		(in millions)		
Adjusted EBITDA	$ 622	$ 460	$ 1,243	$ 2,325
Interest expense, net	(102)	(104)	(211)	(417)
Maintenance capital expenditures	(50)	(55)	(110)	(215)
Current income tax expense	(42)	(6)	(44)	(92)
Other, net	16	(3)	1	14
Implied DCF	$ 444	$ 292		