Williams Partners L.P.
Form 10-Q
October 31, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2012

OR

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

For the transition period from ______ to ______

Commission file number 1-32599

WILLIAMS PARTNERS L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**20-2485124**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
ONE WILLIAMS CENTER	
TULSA, OKLAHOMA	**74172-0172**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (918) 573-2000

NO CHANGE

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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. (Check one):

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

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

The registrant had 355,184,387 common units outstanding as of October 30, 2012.

Table of Contents

Williams Partners L.P.

Index

Certain matters contained in this report include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements relate to anticipated financial performance, management s plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions, and other matters.

All statements, other than statements of historical facts, included in this report that address activities, events, or developments that we expect, believe, or anticipate will exist or may occur in the future are forward-looking statements. Forward-looking statements can be identified by various forms of words such as anticipates, believes, seeks, could, may, should, continues, estimates, expects, assumes, fore goals, objectives, targets, planned, potential, projects, scheduled, will, guidance, outlook, in service date or other similar e statements are based on management s beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

Amounts and nature of future capital expenditures;

Expansion and growth of our business and operations;

1

- Financial condition and liquidity;
- Business strategy;
- Cash flow from operations or results of operations;
- The levels of cash distributions to unitholders;
- Seasonality of certain business components;
- Natural gas and natural gas liquids prices and demand.

Forward-looking statements are based on numerous assumptions, uncertainties, and risks that could cause future events or results to be materially different from those stated or implied in this report. Limited partner units are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider the risk factors discussed below in addition to the other information in this report. If any of the following risks were actually to occur, our business, results of operations, and financial condition could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline, and unitholders could lose all or part of their investment. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Whether we have sufficient cash from operations to enable us to pay current and expected levels of cash distributions following establishment of cash reserves and payment of fees and expenses, including payments to our general partner;
- Availability of supplies, market demand, volatility of prices, and the availability and cost of capital;
- Inflation, interest rates, and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- The strength and financial resources of our competitors;
- Ability to acquire new businesses and assets and integrate those operations and assets into our existing businesses, as well as expand our facilities;
- Development of alternative energy sources;
- The impact of operational and development hazards;

Costs of, changes in, or the results of laws, government regulations (including safety and climate change regulation and changes in natural gas production from exploration and production areas that we serve), environmental liabilities, litigation, and rate proceedings;

Our allocated costs for defined benefit pension plans and other postretirement benefit plans sponsored by our affiliates;

Changes in maintenance and construction costs;

Changes in the current geopolitical situation;

Our exposure to the credit risks of our customers and counterparties;

Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings, and the availability and cost of credit;

Table of Contents

Risks associated with future weather conditions;

Acts of terrorism, including cybersecurity threats and related disruptions;

Additional risks described in our filings with the Securities and Exchange Commission (SEC).

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2011, and Part II, Item 1A. Risk Factors of this Form 10-Q.

Table of Contents

PART I FINANCIAL INFORMATION

Williams Partners L.P.

Consolidated Statement of Comprehensive Income

(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
	(Millions, except per-unit amounts)			
Revenues:				
Gas Pipeline	$ 412	$ 429	$ 1,233	$ 1,252
Midstream Gas & Liquids	1,115	1,244	3,562	3,671
Total revenues	1,527	1,673	4,795	4,923
Segment costs and expenses:				
Costs and operating expenses	1,089	1,172	3,389	3,446
Selling, general, and administrative expenses	86	66	266	207
Other (income) expense net	9	4	27	(8)
Total segment costs and expenses	1,184	1,242	3,682	3,645
General corporate expenses	41	29	123	86
Operating income:				
Gas Pipeline	136	153	430	457
Midstream Gas & Liquids	207	278	683	821
General corporate expenses	(41)	(29)	(123)	(86)
Total operating income	302	402	990	1,192
Equity earnings	30	40	87	101
Interest accrued	(109)	(105)	(329)	(320)
Interest capitalized	8	3	16	8
Interest income	1		2	1
Other income (expense) net	5	2	12	5
Net income	$ 237	$ 342	$ 778	$ 987
Allocation of net income for calculation of earnings per common unit:				
Net income	$ 237	$ 342	$ 778	$ 987
Allocation of net income to general partner	104	79	294	224
Allocation of net income to common units	$ 133	$ 263	$ 484	$ 763
Basic and diluted net income per common unit	$ 0.38	$ 0.91	$ 1.47	$ 2.63
Weighted average number of common units outstanding (thousands)	350,519	290,477	328,649	290,181
Cash distributions per common unit	$ 0.8075	$ 0.7475	$ 2.3775	$ 2.1975
Other comprehensive income (loss):				
Net unrealized gain (loss) from derivative instruments	$ (11)	$ (8)	$ 34	$ (12)
Reclassifications into earnings of net derivative instruments (gain) loss	(14)	6	(20)	10

Other comprehensive income (loss)		(25)		(2)		14		(2)
Comprehensive income	$	212	$	340	$	792	$	985

See accompanying notes.

4

Table of Contents

Williams Partners L.P.

Consolidated Balance Sheet

(Unaudited)

	September 30, 2012	December 31, 2011
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 368	$ 163
Accounts and notes receivable:		
Trade	476	484
Affiliate		9
Inventories	134	148
Regulatory assets	38	40
Other current assets	74	70
Total current assets	1,090	914
Investments	1,626	1,383
Property, plant, and equipment, at cost	19,873	17,755
Accumulated depreciation	(6,504)	(6,128)
Property, plant, and equipment net	13,369	11,627
Goodwill	650	
Other intangibles	1,725	43
Regulatory assets, deferred charges, and other	413	413
Total assets	$ 18,873	$ 14,380
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 668	$ 554
Affiliate	76	57
Accrued interest	109	105
Asset retirement obligations	67	66
Other accrued liabilities	208	166
Long-term debt due within one year		324
Total current liabilities	1,128	1,272
Long-term debt	8,062	6,913
Asset retirement obligations	509	503
Regulatory liabilities, deferred income, and other	500	464
Contingent liabilities (Note 10)		
Equity:		
Common units (355,184,387 units outstanding at September 30, 2012 and 290,477,159 units outstanding at December 31, 2011)	10,160	6,810
General partner	(1,498)	(1,580)
Accumulated other comprehensive income (loss)	12	(2)
Total equity	8,674	5,228

Total liabilities and equity	$ 18,873	$ 14,380

See accompanying notes.

Table of Contents

Williams Partners L.P.

Consolidated Statement of Changes in Equity

(Unaudited)

	Common Units	General Partner	Accumulated Other Comprehensive Income (Loss)	Total Equity
		(Millions)		
Balance December 31, 2011	$ 6,810	$ (1,580)	$ (2)	$ 5,228
Net income	507	271		778
Other comprehensive income (loss)			14	14
Cash distributions	(769)	(277)		(1,046)
Sales of common units	2,559			2,559
Issuances of common units related to acquisitions	1,051			1,051
Contributions from general partner		88		88
Other	2			2
Balance September 30, 2012	$ 10,160	$ (1,498)	$ 12	$ 8,674

See accompanying notes.

6

Table of Contents

Williams Partners L.P.

Consolidated Statement of Cash Flows

(Unaudited)

	Nine months ended September 30, 2012	2011
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 778	$ 987
Adjustments to reconcile to net cash provided by operations:		
Depreciation and amortization	503	459
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	22	(56)
Inventories	25	35
Other current assets and deferred charges	24	(8)
Accounts payable	(104)	73
Accrued liabilities	(2)	51
Affiliate accounts receivable and payable net	28	(66)
Other, including changes in noncurrent assets and liabilities	56	42
Net cash provided by operating activities	$ 1,330	$ 1,517
FINANCING ACTIVITIES:		
Proceeds from long-term debt	2,109	1,023
Payments of long-term debt	(1,285)	(700)
Payment of debt issuance costs	(11)	(12)
Proceeds from sales of common units	2,559	
General partner contributions	88	16
Distributions to limited partners and general partner	(1,046)	(830)
Excess of purchase price over contributed basis of investment		(123)
Other net		2
Net cash provided (used) by financing activities	$ 2,414	$ (624)
INVESTING ACTIVITIES:		
Purchases of investments from affiliates		(174)
Property, plant and equipment:		
Capital expenditures	(1,288)	(598)
Net proceeds from dispositions	22	
Purchases of businesses	(2,049)	(31)
Contributions to equity method investments	(282)	(140)
Other net	58	6
Net cash used by investing activities	$ (3,539)	$ (937)
Increase (decrease) in cash and cash equivalents	205	(44)
Cash and cash equivalents at beginning of period	163	187
Cash and cash equivalents at end of period	$ 368	$ 143

See accompanying notes.

Table of Contents

Williams Partners L.P.

Notes to Consolidated Financial Statements

(Unaudited)

Note 1. General, Description of Business and Basis of Presentation

General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto in our Form 10-K/A Amendment No.1, filed April 9, 2012. The accompanying unaudited financial statements include all normal recurring adjustments that, in the opinion of management, are necessary to present fairly our interim financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Unless the context clearly indicates otherwise, references in this report to we, our, us, or similar language refer to Williams Partners L.P. and its subsidiaries.

Description of Business

We are a publicly traded Delaware limited partnership. Williams Partners GP LLC, a Delaware limited liability company wholly owned by The Williams Companies, Inc. (Williams), serves as our general partner. As of September 30, 2012, Williams owns an approximate 64 percent limited partner interest, a 2 percent general partner interest and incentive distribution rights (IDRs) in us. All of our activities are conducted through Williams Partners Operating LLC, an operating limited liability company (wholly owned by us).

Our operations are located in the United States and are organized into the Gas Pipeline and Midstream Gas & Liquids (Midstream) reporting segments.

Gas Pipeline includes 100 percent of Transcontinental Gas Pipe Line Company, LLC (Transco), 100 percent of Northwest Pipeline GP (Northwest Pipeline), and 50 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream). Our ownership interest in Gulfstream has increased by 1 percent, a result of a second-quarter 2012 acquisition from a subsidiary of Williams (see Note 2).

Midstream is comprised primarily of significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, operations in the Marcellus Shale region, and various equity investments in domestic natural gas gathering and processing assets and natural gas liquid (NGL) fractionation and transportation assets. Midstream s assets also include substantial operations and investments in the Four Corners region, the Piceance basin, as well as an NGL fractionator and storage facilities near Conway, Kansas.

Basis of Presentation

Variable interest entity

Gulfstar One (Gulfstar) is a consolidated wholly-owned subsidiary that, due to certain risk sharing provisions in its customer contracts, is a variable interest entity. We, as construction agent for Gulfstar, will design, construct, and install a proprietary floating-production system, Gulfstar FPS™, and associated pipelines which will initially provide production handling and gathering services for the Tubular Bells oil and gas discovery in the eastern deepwater Gulf of Mexico. Construction is underway and the project is expected to be in service in 2014. We, in combination with certain advance payments from the producer customers, are currently financing the asset construction. As of September 30, 2012, our Consolidated Balance Sheet includes $438 million of Gulfstar construction work in process representing costs incurred to date, included in *property, plant, and equipment, at cost*

Notes (Continued)

and $109 million of deferred revenue, included in *regulatory liabilities, deferred income, and other* associated with the customer advance payments. We are committed to the producer customers to construct this system, and we currently estimate the remaining construction cost to be less than $550 million. If the producer customers do not develop the offshore oil and gas fields to be connected to Gulfstar, they will be responsible for the firm price of building the facilities.

Note 2. Acquisitions

On February 17, 2012, we completed the acquisition of 100 percent of the ownership interests in certain entities from Delphi Midstream Partners, LLC, in exchange for $325 million in cash, net of cash acquired in the transaction, and 7,531,381 of our common units valued at $441 million (Laser Acquisition). The fair value of the common units issued as part of the consideration paid was determined on the basis of the closing market price of our common units on the acquisition date, adjusted to reflect certain time-based restrictions on resale. The acquired entities primarily own the Laser Gathering System, which is comprised of 33 miles of 16-inch natural gas pipeline and associated gathering facilities in the Marcellus Shale in Susquehanna County, Pennsylvania, as well as 10 miles of gathering lines in southern New York.

On April 27, 2012, we completed the acquisition of 100 percent of the ownership interests in Caiman Eastern Midstream, LLC, from Caiman Energy, LLC (Caiman Acquisition) in exchange for $1.72 billion in cash, net of purchase price adjustments and subject to certain closing adjustments, and 11,779,296 of our common units valued at $603 million. The fair value of the common units issued as part of the consideration paid was determined on the basis of the closing market price of our common units on the acquisition date, adjusted to reflect certain time-based restrictions on resale. The acquired entity operates a gathering and processing business in northern West Virginia, southwestern Pennsylvania and eastern Ohio. Acquisition transaction costs of $16 million were incurred related to the Caiman Acquisition and are reported in *selling, general and administrative expenses* at Midstream in the Consolidated Statement of Comprehensive Income.

These acquisitions were accounted for as business combinations which, among other things, require assets acquired and liabilities assumed to be measured at their acquisition-date fair values. The excess of cost over those fair values was recorded as goodwill and allocated to our Northeast gathering and processing businesses (the reporting unit) within the Midstream segment. Goodwill recognized in the acquisitions relates primarily to enhancing our strategic platform for expansion in the area.

The amounts recognized in the financial statements for the Caiman Acquisition are preliminary because our valuation work has not been completed. We are awaiting further information for valuing the working capital components, property, plant and equipment, intangible assets and contingent liabilities. In addition, we are still in the process of identifying all the assets acquired and liabilities assumed.

The following table presents the allocation of the acquisition-date fair value of the major classes of the net assets, which are presented in the Midstream segment:

	Laser	Caiman
Assets held-for-sale	$ 18	$
Other current assets	3	13
Property, plant and equipment	158	663
Intangible assets:		
Customer contracts	316	1,141
Customer relationships		250
Other intangible assets	2	2
Current liabilities	(21)	(98)
Noncurrent liabilities		(4)
Identifiable net assets acquired	476	1,967
Goodwill	290	360
	$ 766	$ 2,327

9

Table of Contents

Notes (Continued)

During the third quarter of 2012, we recognized measurement period adjustments related to the Caiman Acquisition that primarily increased the fair value of the identifiable intangible assets by $80 million at the acquisition date, offset by a decrease to goodwill based on more refined estimates of future cash flows from the identifiable intangible assets. An increase in amortization expense since the acquisition date was also recorded related to this adjustment.

Identifiable intangible assets recognized in the acquisitions are primarily related to gas gathering, processing and fractionation contracts and relationships with customers. The basis for determining the value of these intangible assets is estimated future net cash flows to be derived from acquired customer contracts and relationships, which are offset with appropriate charges for the use of contributory assets and discounted using a risk-adjusted discount rate. Those intangible assets are being amortized on a straight-line basis over an initial 30-year period during which the customer contracts and relationships are expected to contribute to our cash flows.

We expense costs incurred to renew or extend the terms of our gas gathering, processing and fractionation contracts with customers. Approximately 70 and 36 percent of the expected future revenues from the customer contracts associated with the Laser and Caiman Acquisitions, respectively, are impacted by our ability and intent to renew or renegotiate existing customer contracts. Based on the estimated future revenues during the current contract periods, the weighted-average periods prior to the next renewal or extension of the existing customer contracts associated with the Laser and Caiman Acquisitions are approximately 9 and 18 years, respectively.

We will evaluate these intangible assets for both changes in the expected remaining useful lives and impairment when events or changes in circumstances indicate, in our management s judgment, that the estimated useful lives have changed or the carrying value of such assets may not be recoverable. Changes in an estimated remaining useful life would be reflected prospectively through amortization over the revised remaining useful life. When an indicator of impairment has occurred, we compare our management s estimate of undiscounted future cash flows attributable to the intangible assets to the carrying value of the assets to determine whether an impairment has occurred and we apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

The goodwill is not subject to amortization but will be evaluated annually as of October 1 for impairment or more frequently if impairment indicators are present. Our evaluation will include an assessment of events or circumstances to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount. If so, we will further compare our estimate of the fair value of the reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss will be recognized in the amount of the excess.

Revenues and earnings related to the Laser and Caiman Acquisitions included within the Consolidated Statement of Comprehensive Income since the respective acquisition dates are not material. Supplemental pro forma revenue and earnings reflecting these acquisitions as if they had occurred as of January 1, 2011, are not materially different from the information presented in our accompanying Consolidated Statement of Comprehensive Income (since the historical operations of these acquisitions were insignificant relative to our historical operations) and are, therefore, not presented.

Table of Contents

Notes (Continued)

On June 14, 2012, we acquired a 1 percent interest in Gulfstream from a subsidiary of Williams in exchange for 238,050 of our limited partner units and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest. As the acquired equity interest was purchased from a subsidiary of Williams, the transaction was accounted for as a combination of entities under common control whereby the investment acquired is combined with ours at its historical amount as of the date of transfer. This investment is reported in our Gas Pipeline segment.

Note 3. Allocation of Net Income and Distributions

The allocation of net income between our general partner and limited partners for the three and nine months ended September 30, 2012 and 2011 is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
	(Millions)			
Allocation of net income to general partner:				
Net income	$ 237	$ 342	$ 778	$ 987
Net reimbursable costs charged directly to general partner	1		1	(2)
Income subject to 2% allocation of general partner interest	238	342	779	985
General partner s share of net income	2 %	2 %	2 %	2 %
General partner s allocated share of net income before items directly allocable to general partner interest	5	7	16	20
Incentive distributions paid to general partner (a)	92	67	256	189
Net reimbursable costs charged directly to general partner	(1)		(1)	2
Net income allocated to general partner	$ 96	$ 74	$ 271	$ 211
Net income	$ 237	$ 342	$ 778	$ 987
Net income allocated to general partner	96	74	271	211
Net income allocated to common limited partners	$ 141	$ 268	$ 507	$ 776

(a) The net income allocated to the general partner s capital account reflects IDRs paid during the current reporting period. In the calculation of basic and diluted net income per limited partner unit, the net income allocated to the general partner includes IDRs pertaining to the current reporting period, but paid in the subsequent period.

The *net reimbursable costs charged directly to general partner* may include the net of both income and expense items. Under the terms of omnibus agreements, we are reimbursed by our general partner for certain expense items and are required to distribute certain income items to our general partner.

Table of Contents

Notes (Continued)

We paid or have authorized payment of the following partnership cash distributions during 2011 and 2012 (in millions, except for per unit amounts):

Payment Date	Per Unit Distribution	Common Units	General Partner 2%	General Partner Incentive Distribution Rights	Total Cash Distribution
2/11/2011	$ 0.7025	$ 204	$ 5	$ 59	$ 268
5/13/2011	$ 0.7175	$ 208	$ 5	$ 63	$ 276
8/12/2011	$ 0.7325	$ 213	$ 6	$ 67	$ 286
11/11/2011	$ 0.7475	$ 217	$ 6	$ 71	$ 294
2/10/2012	$ 0.7625	$ 227	$ 6	$ 78	$ 311
5/11/2012	$ 0.7775	$ 268	$ 8	$ 86	$ 362
8/10/2012	$ 0.7925	$ 274	$ 7	$ 92	$ 373
11/09/2012 (b)	$ 0.8075	$ 287	$ 8	$ 99	$ 394

(b) The Board of Directors of our general partner declared this $0.8075 per unit cash distribution on October 22, 2012, to be paid on November 9, 2012, to unitholders of record at the close of business on November 2, 2012.

The 2012 cash distributions to our general partner in the table above have been reduced by a total of $24 million resulting from the temporary waiver of IDRs associated with the Caiman Acquisition.

Table of Contents

Notes (Continued)

Note 4. Other Accruals

We detected a leak in an underground cavern at our Eminence Storage Field in Mississippi on December 28, 2010. We recorded charges of $1 million and $6 million during the three months ended September 30, 2012 and 2011, respectively, and $2 million and $13 million during the nine months ended September 30, 2012 and 2011, respectively, to *costs and operating expenses* at Gas Pipeline primarily related to assessment and monitoring costs incurred to ensure the safety of the surrounding area.

Other (income) expense net within *segment costs and expenses* at Gas Pipeline in the nine months ended September 30, 2012, includes $17 million of project feasibility costs associated with natural gas pipeline expansion projects. The nine months ended September 30, 2011, includes a $10 million reversal of project feasibility costs from expense to capital. This reversal was made upon determining that the related project was probable of development. These costs are now included in the capital costs of the project, which we believe are probable of recovery through the project rates.

General corporate expenses in the three and nine months ended September 30, 2012, includes $6 million and $13 million, respectively, of expense related to Williams engagement of a consulting firm to assist in better aligning resources to support our business strategy following Williams spin-off of WPX Energy, Inc. (WPX).

Note 5. Inventories

	September 30, 2012	December 31, 2011
	(Millions)	
Natural gas liquids and natural gas in underground storage	$ 65	$ 80
Materials, supplies, and other	69	68
	$ 134	$ 148

Note 6. Debt and Banking Arrangements

Credit Facility

In September 2012, we amended our existing $2 billion senior unsecured revolving credit facility to increase the aggregate commitments by $400 million. This facility was also amended to provide that we may request an additional $400 million increase in commitments to be available under certain conditions in the future.

Letter of credit capacity under our amended $2.4 billion credit facility is $1.3 billion. At September 30, 2012, no letters of credit have been issued and no loans are outstanding under the credit facility.

Issuances and Retirements

In August 2012, we completed a public offering of $750 million of 3.35 percent senior unsecured notes due 2022. We used the net proceeds to repay outstanding borrowings on our senior unsecured revolving credit facility and for general partnership purposes.

In July 2012, Transco issued $400 million of 4.45 percent senior unsecured notes due 2042 to investors in a private debt placement. A portion of these proceeds was used to repay Transco s $325 million 8.875 percent senior unsecured notes that matured on July 15, 2012. As part of the new issuance, Transco entered into a registration rights agreement with the initial purchasers of the unsecured notes. Transco is obligated to file a registration statement for an offer to exchange the notes for a new issue of substantially identical notes registered under the

Notes (Continued)

Securities Act of 1933, as amended, within 180 days from closing and to use commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing and to consummate the exchange offer within 30 business days after such effective date. Transco is required to provide a shelf registration statement to cover resales of the notes under certain circumstances. If Transco fails to fulfill these obligations, additional interest will accrue on the affected securities. The rate of additional interest will be 0.25 percent per annum on the principal amount of the affected securities for the first 90-day period immediately following the occurrence of default, increasing by an additional 0.25 percent per annum with respect to each subsequent 90-day period thereafter, up to a maximum amount for all such defaults of 0.5 percent annually. Following the cure of any registration defaults, the accrual of additional interest will cease.

In August 2011, Transco issued $375 million of 5.4 percent senior unsecured notes due 2041 to investors in a private debt placement. As part of the new issuance, Transco entered into a registration rights agreement with the initial purchasers of the notes. An offer to exchange these unregistered notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended, was commenced in February 2012 and completed in March 2012.

Note 7. Partners Capital

On January 30, 2012, we completed an equity issuance of 7,000,000 common units representing limited partner interests in us at a price of $62.81 per unit. The net proceeds were used to fund capital expenditures and for other partnership purposes.

On February 17, 2012, we closed the Laser Acquisition. In connection with this transaction, we issued 7,531,381 of our common units. (See Note 2.)

On February 28, 2012, we sold an additional 1,050,000 common units, at a price of $62.81 per unit, to the underwriters upon the underwriters exercise of their option to purchase additional common units pursuant to our common unit offering in January 2012. The net proceeds were used for general partnership purposes.

On April 10, 2012, we completed an equity issuance of 10,000,000 common units representing limited partner interests at a price of $54.56 per unit. On April 26, 2012, we sold an additional 973,368 common units at a price of $54.56 per unit to the underwriters upon the underwriters exercise of their option to purchase additional common units. The net proceeds were used for general partnership purposes, including the funding of a portion of the cash purchase price of the Caiman Acquisition. (See Note 2.) We also used $1 billion in proceeds from the April 27, 2012, sale of 16,360,133 common units to Williams to fund the Caiman Acquisition.

On April 27, 2012, we closed the Caiman Acquisition. In connection with this transaction, we issued 11,779,296 of our common units. (See Note 2.)

On June 14, 2012, we closed the acquisition of a 1 percent interest in Gulfstream from a subsidiary of Williams. In connection with this transaction, we issued 238,050 of our common units. (See Note 2.)

On August 13, 2012, we completed an equity issuance of 8,500,000 common units representing limited partner interests at a price of $51.43 per unit. On August 20, 2012, we sold an additional 1,275,000 common units at a price of $51.43 per unit to the underwriters upon the underwriters exercise of their option to purchase additional common units. The net proceeds were used to repay amounts outstanding under our revolving credit facility and for general partnership purposes.

Note 8. Fair Value Measurements

The following table presents, by level within the fair value hierarchy, certain of our financial assets and liabilities. The carrying values of cash and cash equivalents, accounts receivable and accounts payable approximate fair value because of the short-term nature of these instruments. Therefore, these assets and liabilities are not presented in the following table.

Table of Contents

Notes (Continued)

	Carrying Amount	Fair Value	Fair Value Measurements Using Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(Millions)		
Assets (liabilities) at September 30, 2012:					
Measured on a recurring basis:					
ARO Trust investments	$ 21	$ 21	$ 21	$	$
Energy derivatives assets not designated as hedging instruments	2	2	1	1	
Energy derivatives assets designated as hedging instruments	15	15	9	6	
Energy derivatives liabilities not designated as hedging instruments	(1)	(1)		(1)	
Additional disclosures:					
Notes receivable and other	9	9		9	
Long-term debt, including current portion	(8,062)	(9,329)		(9,329)	
Customer margin deposits payable	(6)	(6)	(6)		
Assets (liabilities) at December 31, 2011:					
Measured on a recurring basis:					
ARO Trust investments	$ 25	$ 25	$ 25	$	$
Energy derivatives assets not designated as hedging instruments	1	1	1		
Additional disclosures:					
Notes receivable and other	10	10	N/A	N/A	N/A
Long-term debt, including current portion	(7,237)	(8,170)	N/A	N/A	N/A

Fair Value Methods

We use the following methods and assumptions in estimating the fair value of our financial instruments:

Assets and liabilities measured at fair value on a recurring basis

ARO Trust investments: Transco deposits a portion of its collected rates, pursuant to its 2008 rate case settlement, into an external trust (ARO Trust) that is specifically designated to fund future asset retirement obligations. The ARO Trust invests in a portfolio of actively traded mutual funds that are measured at fair value on a recurring basis based on quoted net asset values, is classified as available-for-sale, and is reported in *regulatory assets, deferred charges, and other* in the Consolidated Balance Sheet. Both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

Energy derivatives: Energy derivatives include commodity based exchange-traded contracts and over-the-counter (OTC) contracts, which consist solely of swaps that are measured at fair value on a recurring basis. The tenure of our energy derivatives portfolio is relatively short with all of our energy derivative contracts expiring in the next six months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions. Energy derivatives are reported in *other current assets* and *other accrued liabilities* in the Consolidated Balance Sheet.

Energy derivatives considered Level 1 measurements consist of New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets.

Energy derivatives included in our Level 2 measurements consist solely of OTC swaps. Swap contracts included in Level 2 are valued using an income approach including present value techniques. Significant inputs into our Level 2 valuations include commodity prices and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No transfers between Level 1 and Level 2 occurred during the nine months ended September 30, 2012 or 2011.

Additional fair value disclosures

Notes receivable and other: The disclosed fair value of our notes receivable is determined by an income approach which considers the underlying contract amounts and our assessment of our ability to recover these amounts. The current portion is reported in *accounts and notes receivable*, and the noncurrent portion is reported in *regulatory assets, deferred charges, and other* in the Consolidated Balance Sheet.

Long-term debt: The disclosed fair value of our long-term debt is determined by a market approach using broker quoted indicative period-end bond prices. The quoted prices are based on observable transactions in less active markets for our debt or similar instruments.

Customer margin deposits payable: The disclosed fair value of our customer margin deposits payable is considered to approximate the carrying value generally due to the short-term nature of these items and is reported in *other accrued liabilities* in the Consolidated Balance Sheet.

Guarantees

We are required by our revolving credit agreement to indemnify lenders for certain taxes required to be withheld from payments due to the lenders and for certain tax payments made by the lenders. The maximum potential amount of future payments under these indemnifications is based on the related borrowings and such future payments cannot currently be determined. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications and have no current expectation of a future claim.

Notes (Continued)

Note 9. Derivative Instruments

Energy Commodity Derivatives

Risk management activities

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases of natural gas and forecasted sales of NGLs attributable to commodity price risk. Certain of these derivatives utilized for risk management purposes have been designated as cash flow hedges, while other derivatives have not been designated as cash flow hedges or do not qualify for hedge accounting despite hedging our future cash flows on an economic basis.

We sell NGL volumes received as compensation for certain processing services at different locations throughout the United States. We also buy natural gas to satisfy the required fuel and shrink needed to generate NGLs. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices or increases in costs and operating expenses from fluctuations in natural gas market prices, we may enter into NGL or natural gas swap agreements, financial or physical forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs and purchases of natural gas. Those designated as cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

Volumes

Our energy commodity derivatives are comprised of both contracts to purchase commodities (long positions) and contracts to sell commodities (short positions). Derivative transactions are categorized into two types:

Central hub risk: Financial derivative exposures to Henry Hub for natural gas and Mont Belvieu for NGLs;

Basis risk: Financial derivative exposures to the difference in value between the central hub and another specific delivery point.

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of September 30, 2012. Natural gas is presented in millions of British Thermal Units (MMBtu) and NGLs are presented in barrels.

Derivative Notional Volumes	**Unit of Measure**	**Central Hub Risk**	**Basis Risk**
Designated as Hedging Instruments			
Midstream	Barrels	(885,000)	
Midstream	MMBtu	3,905,400	3,252,200
Not Designated as Hedging Instruments			
Midstream	Barrels	(20,000)	165,000

Gains (losses)

The following table presents gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in *accumulated other comprehensive income* (AOCI), *revenues,* or *costs and operating expenses.*

	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011	Classification
	(Millions)				
Net gain (loss) recognized in other comprehensive income (loss) (effective portion)	$ (12)	$ (8)	$ 34	$ (14)	AOCI
Net gain (loss) reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$ 13	$ (6)	$ 19	$ (10)	Revenues or Costs and Operating Expenses

We recognized gains of less than $1 million in income as a result of hedge ineffectiveness for the nine months ended September 30, 2012. There were no gains or losses recognized in income as a result of reclassifications to earnings following the discontinuance of any cash flow hedges, or as a result of excluding amounts from the assessment of hedge effectiveness.

We recognized gains of $1 million and losses of $1 million in *revenues* for the nine months ended September 30, 2012 and 2011, respectively, on our energy commodity derivatives not designated as hedging instruments.

The cash flow impact of our derivative activities is presented in the Consolidated Statement of Cash Flows as *other, including changes in noncurrent assets and liabilities*.

Credit-risk-related features

Certain of our derivative contracts contain credit-risk-related provisions that would require us, in certain circumstances, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor s and/or Moody s Investors Service. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability.

At both September 30, 2012, and December 31, 2011, we did not have any collateral posted, either in the form of cash or letters of credit, to derivative counterparties.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in AOCI and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. As of September 30, 2012, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales through the end of 2012. Based on recorded values at September 30, 2012, $14 million of net gains will be reclassified into earnings within the next three months. These recorded values are based on forward market prices of the commodities as of September 30, 2012. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized within the next three months will likely differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Note 10. Contingent Liabilities

Environmental Matters

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations and remedial processes at certain sites, some of which we currently do not own. We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), and other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws. As of September 30, 2012, we have accrued liabilities totaling $18 million for these matters, as discussed below. Our accrual reflects the most likely costs of cleanup, which are generally based on completed assessment studies, preliminary results of studies or our experience with other similar cleanup operations. Certain assessment studies are still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Any incremental amount in excess of amounts currently accrued cannot be reasonably estimated at this time due to uncertainty about the actual number of contaminated sites ultimately identified, the actual amount and extent of contamination discovered and the final cleanup standards mandated by the EPA and other governmental authorities.

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. More recent rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, new air quality standards for ground level ozone, and one hour nitrogen dioxide emission limits. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Our interstate gas pipelines are involved in remediation activities related to certain facilities and locations for polychlorinated biphenyls, mercury, and other hazardous substances. These activities have involved the EPA and various state environmental authorities, resulting in our identification as a potentially responsible party at various Superfund waste sites. At September 30, 2012, we have accrued liabilities of $10 million for these costs. We expect that these costs will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At September 30, 2012, we have accrued liabilities totaling $8 million for these costs.

Rate Matters

On August 31, 2006, Transco submitted to the Federal Energy Regulatory Commission (FERC) a general rate filing (Docket No. RP06-569) principally designed to recover increased costs. The rates became effective March 1, 2007, subject to refund and the outcome of a hearing. All issues in this proceeding except one have been resolved by settlement.

The one issue reserved for litigation or further settlement relates to Transco s proposal to change the design of the rates for service under one of its storage rate schedules, which was implemented subject to refund on March 1, 2007. A hearing on that issue was held before a FERC Administrative Law Judge (ALJ) in July 2008. In November 2008, the ALJ issued an initial decision in which he determined that Transco s proposed incremental rate design is unjust and unreasonable. On January 21, 2010, the FERC reversed the ALJ s initial decision, and approved our proposed incremental rate design. Certain parties sought rehearing of the FERC s order and, on April 2, 2012, the FERC denied the rehearing request. On June 1, 2012, one party filed an appeal in the U.S. Court of Appeals for the D.C. Circuit challenging the FERC s orders approving our rate design proposal.

Other

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

Notes (Continued)

Summary

We estimate that for all matters for which we are able to reasonably estimate a range of loss, including those noted above and others that are not individually significant, our aggregate reasonably possible losses beyond amounts accrued for all of our contingent liabilities are immaterial to our expected future annual results of operations, liquidity, and financial position. These calculations have been made without consideration of any potential recovery from third parties. We disclose all significant matters for which we are unable to reasonably estimate a range of possible loss.

Note 11. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies, and industry knowledge.

Performance Measurement

We currently evaluate segment operating performance based on *segment profit* from operations, which includes *segment revenues* from external customers, *segment costs and expenses,* and *equity earnings*.

The primary types of costs and operating expenses by segment can be generally summarized as follows:

Gas Pipeline depreciation and operation and maintenance expenses;

Midstream commodity purchases (primarily for NGL, natural gas, and crude marketing, shrink, and fuel), depreciation, and operation and maintenance expenses.

Table of Contents

Notes (Continued)

The following table reflects the reconciliation of *segment profit* to *operating income* as reported in the Consolidated Statement of Comprehensive Income.

	Gas Pipeline	Midstream (Millions)	Total
Three months ended September 30, 2012			
Segment revenues	$ 412	$ 1,115	$ 1,527
Segment profit	$ 155	$ 218	$ 373
Less equity earnings	19	11	30
Segment operating income	$ 136	$ 207	343
General corporate expenses			(41)
Total operating income			$ 302
Three months ended September 30, 2011			
Segment revenues	$ 429	$ 1,244	$ 1,673
Segment profit	$ 170	$ 301	$ 471
Less equity earnings	17	23	40
Segment operating income	$ 153	$ 278	431
General corporate expenses			(29)
Total operating income			$ 402
Nine months ended September 30, 2012			
Segment revenues	$ 1,233	$ 3,562	$ 4,795
Segment profit	$ 482	$ 718	$ 1,200
Less equity earnings	52	35	87
Segment operating income	$ 430	$ 683	1,113
General corporate expenses			(123)
Total operating income			$ 990
Nine months ended September 30, 2011			
Segment revenues	$ 1,252	$ 3,671	$ 4,923
Segment profit	$ 497	$ 882	$ 1,379
Less equity earnings	40	61	101
Segment operating income	$ 457	$ 821	1,278

General corporate expenses	(86)
Total operating income	$ 1,192

Table of Contents

Notes (Continued)

The following table reflects *total assets* by reporting segment.

	Total Assets	
	September 30, 2012	December 31, 2011
	(Millions)	
Gas Pipeline	$ 8,656	$ 8,348
Midstream (1)	10,531	6,591
Other corporate assets	418	226
Eliminations (2)	(732)	(785)
Total	$ 18,873	$ 14,380

(1) The increase in Midstream s total assets as compared to the prior year-end is substantially due to the Laser Acquisition in the first quarter of 2012 and the Caiman Acquisition in the second quarter of 2012. (See Note 2.)

(2) Eliminations primarily relate to the intercompany accounts receivable generated by our cash management program.

Note 12. Subsequent Events

In October 2012, we agreed to purchase Williams 83.3 percent undivided interest and operatorship of the olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf region for total consideration valued at approximately $2.364 billion, including 42,778,812 limited partner units, $25 million in cash, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest. The transaction is expected to close in November 2012.

Table of Contents

Item 2

Management s Discussion and Analysis of

Financial Condition and Results of Operations

General

We are primarily an energy infrastructure company focused on connecting North America s significant hydrocarbon resource plays to growing markets for natural gas and natural gas liquids (NGLs). We manage our business and analyze our results of operations on a segment basis. Our operations are divided into two business segments: Gas Pipeline and Midstream Gas & Liquids (Midstream).

Gas Pipeline includes Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline GP (Northwest Pipeline), which own and operate a combined total of approximately 13,700 miles of pipelines. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 50 percent interest in Gulfstream Natural Gas System L.L.C. (Gulfstream), which owns an approximate 745-mile pipeline. Our ownership interest in Gulfstream has increased by 1 percent, a result of a second-quarter 2012 acquisition from a subsidiary of The Williams Companies, Inc. (Williams).

Midstream is comprised primarily of significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, operations in the Marcellus Shale region, and various equity investments in domestic natural gas gathering and processing assets and NGL fractionation and transportation assets. Midstream s assets also include substantial operations and investments in the Four Corners region, the Piceance basin, as well as an NGL fractionator and storage facilities near Conway, Kansas.

Williams currently holds an approximate 66 percent interest in us, comprised of an approximate 64 percent limited partner interest and all of our 2 percent general partner interest.

Unless indicated otherwise, the following discussion and analysis of critical accounting estimates, results of operations, and financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto of this Form 10-Q and Amendment No. 1 to our 2011 Annual Report on Form 10-K/A, filed April 9, 2012.

Acquisitions

In February 2012, we completed the acquisition of 100 percent of the ownership interests in certain entities from Delphi Midstream Partners, LLC (Laser Acquisition). These entities primarily own the Laser Gathering System, which is comprised of 33 miles of 16-inch natural gas pipeline and associated gathering facilities in the Marcellus Shale in Susquehanna County, Pennsylvania, as well as 10 miles of gathering lines in southern New York. This acquisition represents a strategic platform to enhance our expansion in the Marcellus Shale by providing our customers with both operational flow assurance and marketing flexibility. (See Results of Operations Segments, Midstream.)

In April 2012, we completed the acquisition of 100 percent of the ownership interest in Caiman Eastern Midstream, LLC (Caiman Acquisition). The acquired entity operates a gathering and processing business in northern West Virginia, southwestern Pennsylvania and eastern Ohio. We believe the acquisition will provide us with a significant footprint and growth potential in the NGL-rich portion of the Marcellus Shale. (See Results of Operations Segments, Midstream.)

Distributions

In October 2012 our general partner s Board of Directors approved a 2 percent increase to our quarterly distribution to unitholders. (See Management s Discussion and Analysis of Financial Condition and Liquidity.)

Table of Contents

Management s Discussion and Analysis (Continued)

Overview of Nine Months Ended September 30, 2012

Net Income for the nine months ended September 30, 2012, changed unfavorably by $209 million compared to the nine months ended September 30, 2011, primarily due to lower NGL production and marketing margins, higher operating costs and *selling, general, and administrative expenses* (SG&A), partially offset by an increase in fee revenue. (See Results of Operations Segments, Midstream.)

Our *net cash provided by operating activities* for the nine months ended September 30, 2012, decreased $187 million compared to the nine months ended September 30, 2011, primarily due to lower operating income.

Recent Events

In February 2012, we announced a new interstate gas pipeline project. The new 120-mile Constitution Pipeline will connect our gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems. We currently own 75 percent of Constitution Pipeline. This project, along with the newly acquired Laser Gathering System and our Springville pipeline are key steps in our strategy to create the Susquehanna Supply Hub, a major natural gas supply hub in northeastern Pennsylvania. In April 2012, we began the Federal Energy Regulatory Commission (FERC) pre-filing process for this project and expect to file a FERC application in January 2013.

In April 2012, we completed an equity issuance of 10 million common units representing limited partner interests in us at a price of $54.56 per unit. Subsequently, we sold an additional 973,368 common units for $54.56 per unit to the underwriters upon the underwriters exercise of their option to purchase additional common units. We also sold 16,360,133 common units to Williams for $1 billion. The net proceeds of these transactions were used for general partnership purposes, including funding a portion of the cash purchase price of the Caiman Acquisition.

In July 2012, Transco issued $400 million of 4.45 percent senior unsecured notes due 2042 to investors in a private debt placement. A portion of these proceeds was used to repay Transco s $325 million 8.875 percent senior unsecured notes that matured on July 15, 2012.

In July 2012, we completed an agreement with Caiman Energy, LLC and others to develop large-scale natural gas gathering and processing and the associated liquids infrastructure serving oil and gas producers in the Utica shale, primarily in Ohio and northwest Pennsylvania. The parties anticipate investing approximately $800 million in potential development over the next several years, of which we expect to fund approximately $380 million.

Following Williams spin-off of WPX Energy, Inc. (WPX) at the end of 2011 and in consideration of the growth plans of the ongoing business, Williams has initiated an effort to better align resources to support our business strategy in 2012 and beyond. This initiative is designed to enhance capabilities and determine the right organization throughout the business areas and shared-services functions to execute that strategy. Williams has engaged a consulting firm to assist with this project and expects to implement changes later this year through early 2013. The recommendations arising from this effort will result in changes in our current organizational structure that will impact how our businesses are managed and thus is expected to result in changes to our future segment reporting structure beginning in 2013.

In August 2012, we completed an equity issuance of 8,500,000 common units representing limited partner interests in us at a price of $51.43 per unit. Subsequently, we sold an additional 1,275,000 common units for $51.43 per unit to the underwriters upon the underwriters exercise of their option to purchase additional common units. The net proceeds of these transactions were primarily used to repay outstanding borrowings on our senior unsecured revolving credit facility (revolver).

In August 2012, we completed a public offering of $750 million of 3.35 percent senior unsecured notes due 2022. We used the net proceeds to repay outstanding borrowings on our revolver and for general partnership purposes.

Table of Contents

Management s Discussion and Analysis (Continued)

In October 2012, we agreed to purchase Williams 83.3 percent undivided interest and operatorship of an olefins-production facility located in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf region for total consideration valued at approximately $2.364 billion. The acquisition is expected to bring more certainty to cash flows that are currently exposed to volatile ethane prices by shifting the commodity price exposure to ethylene. We expect to fund substantially all of the transaction with the issuance of limited partner units to Williams. The transaction is expected to close in November 2012.

Company Outlook

During the second quarter of 2012, NGL margins declined sharply largely attributable to a record-warm winter, a slowing global economy, and growing NGL supplies. The downward trend of per-unit NGL margins has leveled-off during third quarter 2012 and we anticipate a modest level of improvement through the end of the year. However, economic and commodity price indicators can be volatile and it is reasonably possible that the global economy could worsen and/or energy commodity margins may decline, negatively impacting our future operating results. Over the next few years, we expect the influence of NGL margins on our operating results to diminish as we transition to an overall business mix that is increasingly fee-based.

Our business plan for the remainder of 2012 continues to reflect both growth in distributions and significant capital investments. Our planned capital investments total approximately $8.167 billion, including equity issued in the previously discussed acquisitions. We expect to fund a significant portion of these activities through debt and/or equity issuances. We expect to maintain an attractive cost of capital and reliable access to capital markets, both of which will allow us to pursue development projects and acquisitions. We expect to be able to grow through these continued investments in our businesses in a way that meets customer needs and enhances our competitive position by:

- Continuing to invest in and grow our midstream businesses and interstate natural gas pipeline systems;
- Retaining the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.

Potential risks and obstacles that could impact the execution of our plan include:

- General economic, financial markets, or industry downturn;
- Lower than anticipated energy commodity margins;
- Availability of capital;
- Lower than expected levels of cash flow from operations;
- Counterparty credit and performance risk;
- Decreased volumes from third parties served by our midstream business;

Changes in the political and regulatory environments;

Physical damages to facilities, especially damage to offshore facilities by named windstorms.

We continue to address these risks through disciplined investment strategies, commodity hedging strategies, and maintaining ample liquidity from cash and cash equivalents and unused revolver capacity.

Table of Contents

Management s Discussion and Analysis (Continued)

Williams incurs certain corporate general and administrative costs which are charged to its business segments, including us. We expect an increase in our proportionate share of these costs in 2012, due in part to Williams December 2011 spin-off of WPX, its former exploration and production business.

Critical Accounting Estimates

We completed the Laser Acquisition in February 2012 and the Caiman Acquisition in April 2012. Based on the final Laser and preliminary Caiman fair value measurements, our September 30, 2012, Consolidated Balance Sheet includes $650 million of goodwill related to these acquisitions, which we allocated to our Northeast gathering and processing businesses (the reporting unit) within the Midstream segment. (See Note 2 of Notes to Consolidated Financial Statements.) We will evaluate the goodwill for impairment annually as of October 1 or more frequently if impairment indicators are present. These indicators may include materially unfavorable changes in market fundamentals such as sustained reductions in producer drilling activity, changes in our business strategy in this area, our ability to fund expected levels of investment and significantly lower than expected operating results. Our evaluation will include an assessment of events or circumstances to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount. If so, we will further compare our estimate of the fair value of the reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss will be recognized in the amount of the excess.

As a result of these acquisitions, we have also recorded a total of approximately $1.7 billion in intangible assets as of September 30, 2012. The identifiable intangible assets recognized in the acquisitions are primarily related to gas gathering, processing and fractionation contracts and relationships with customers. These intangible assets are being amortized on a straight-line basis over an initial 30-year period during which the customer contracts and relationships are expected to contribute to our cash flows.

We will evaluate these intangible assets for both changes in the expected remaining useful lives and impairment when events or changes in circumstances indicate, in our management s judgment, that the estimated useful lives have changed or the carrying value of such assets may not be recoverable. Changes in an estimated remaining useful life would be reflected prospectively through amortization over the revised remaining useful life. When an indicator of impairment has occurred, we compare our management s estimate of undiscounted future cash flows attributable to the intangible assets to the carrying value of the assets to determine whether an impairment has occurred and we apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

Table of Contents

Management s Discussion and Analysis (Continued)

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2012, compared to the three and nine months ended September 30, 2011. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended September 30,				Nine months ended September 30,			
	2012	2011	$ Change*	% Change*	2012	2011	$ Change*	% Change*
	(Millions)				(Millions)			
Revenues	$ 1,527	$ 1,673	-146	-9%	$ 4,795	$ 4,923	-128	-3%
Costs and expenses:								
Costs and operating expenses	1,089	1,172	+83	+7%	3,389	3,446	+57	+2%
Selling, general, and administrative expenses	86	66	-20	-30%	266	207	-59	-29%
Other (income) expense net	9	4	-5	-125%	27	(8)	-35	NM
General corporate expenses	41	29	-12	-41%	123	86	-37	-43%
Total costs and expenses	1,225	1,271			3,805	3,731		
Operating income	302	402			990	1,192		
Equity earnings	30	40	-10	-25%	87	101	-14	-14%
Interest accrued net	(101)	(102)	+1	+1%	(313)	(312)	-1	
Interest income	1		+1	NM	2	1	+1	+100%
Other income (expense) net	5	2	+3	+150%	12	5	+7	+140%
Net income	$ 237	$ 342	-105	-31%	$ 778	$ 987	-209	-21%

* + = Favorable change; - = Unfavorable change; NM = A percentage calculation is not meaningful due to a change in signs, a zero-value denominator, or a percentage change greater than 200.

Three months ended September 30, 2012 vs. three months ended September 30, 2011

The decrease in *revenues* is primarily due to Midstream s lower NGL production and marketing revenues reflecting an overall decrease in average NGL per-unit sales prices. The lower NGL marketing revenues are partially offset by higher NGL volumes and new volumes from natural gas marketing activities. These decreases are partially offset by Midstream s increased fee revenues primarily due to higher gathering and processing fee revenues resulting from higher volumes in the Marcellus Shale, including new volumes on our recently acquired natural gas gathering and processing assets in our Ohio Valley Midstream and Susquehanna Supply Hub businesses.

The decrease in *costs and operating expenses* is primarily due to decreased costs at Midstream associated with NGL marketing purchases largely due to lower average NGL prices, partially offset by higher NGL volumes and new volumes from natural gas marketing activities. In addition, Midstream s NGL production costs decreased reflecting lower average natural gas prices. These decreases are partially offset by Midstream s higher operating costs resulting from our acquisition transactions in 2012 and increased depreciation on certain assets in the Gulf Coast region, as well as Gas Pipeline s increased maintenance expenses.

The increase in SG&A is primarily due to an increase at Midstream reflecting higher employee-related expenses and information technology costs driven by general growth within Midstream s business operations.

The increase in *general corporate expenses* includes an increase in our proportionate share of these costs as a result of Williams spin-off of WPX, which was completed on December 31, 2011. In addition, *general corporate expenses* in 2012 includes $6 million of expense related to Williams engagement of a consulting firm to better align resources to support our business strategy following Williams spin-off of WPX.

Table of Contents

Management s Discussion and Analysis (Continued)

The decrease in *operating income* generally reflects lower NGL production margins primarily driven by energy commodity price changes including lower NGL prices, partially offset by lower natural gas prices, and higher operating costs and SG&A, partially offset by increased fee revenues as previously discussed.

Equity earnings decreased primarily due to lower Discovery Producer Services LLC (Discovery) and Aux Sable Liquid Products LP (Aux Sable) equity earnings at Midstream primarily due to lower operating results.

Nine months ended September 30, 2012 vs. nine months ended September 30, 2011

The decrease in *revenues* is primarily due to Midstream s lower NGL production revenues reflecting an overall decrease in average NGL per-unit sales prices. Partially offsetting this decrease is Midstream s higher fee revenues resulting from increased gathering and processing fee revenues from higher volumes in the Marcellus Shale, including new volumes on our recently acquired gathering and processing assets in our Ohio Valley Midstream and Susquehanna Supply Hub businesses and higher volumes in the western deepwater Gulf of Mexico and in the Piceance basin. Additionally, Gas Pipeline s higher transportation revenues from expansion projects placed into service in 2011 and 2012 also partially offset this decrease.

The decrease in *costs and operating expenses* is primarily due to decreased costs at Midstream associated with production of NGLs reflecting a decrease in average natural gas prices. Partially offsetting this decrease is increased operating costs at Midstream resulting from our acquisition transactions in 2012 and higher maintenance expenses, partially offset by lower costs in our Four Corners area related to the consolidation of certain operations. In addition, marketing purchases at Midstream increased primarily due to higher volumes, partially offset by significantly lower average NGL prices.

The increase in SG&A is primarily due to an increase at Midstream reflecting acquisition and transition-related costs as well as higher information technology and employee-related expenses driven by general growth within Midstream s business operations.

The unfavorable change in o*ther (income) expense net* within *operating income* primarily reflects a $15 million increase in project feasibility costs and the absence of a $10 million reversal of project feasibility costs from expense to capital in 2011, both at Gas Pipeline.

The increase in *general corporate expenses* is primarily due to an increase in our proportionate share of these costs as a result of Williams spin-off of WPX, which was completed on December 31, 2011. In addition, *general corporate expenses* in 2012 includes $13 million of expense due to Williams engagement of a consulting firm to better align resources to support our business strategy following Williams spin-off of WPX.

The decrease in *operating income* generally reflects lower NGL production margins primarily due to energy commodity price changes including lower NGL prices, partially offset by lower natural gas prices, a decrease in margins related to the marketing of NGLs, and higher operating costs and SG&A, partially offset by increased fee revenues as previously discussed.

Equity earnings decreased primarily due to lower Laurel Mountain Midstream, LLC (Laurel Mountain), Aux Sable and Discovery equity earnings at Midstream primarily reflecting lower operating results, partially offset by an increase in equity earnings at Gas Pipeline primarily resulting from the acquisition of an additional 24.5 percent interest in Gulfstream in May 2011.

Table of Contents

Management s Discussion and Analysis (Continued)

Results of Operations Segments

Gas Pipeline

Overview of Nine Months Ended September 30, 2012

Gas Pipeline s strategy to create value focuses on maximizing the utilization of our pipeline capacity by providing high quality, low cost transportation of natural gas to large and growing markets.

Gas Pipeline s interstate transmission and storage activities are subject to regulation by the Federal Energy Regulatory Commission (FERC) and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, expansion or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established through the FERC s ratemaking process. Changes in commodity prices and volumes transported have little near-term impact on revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

Outlook for the Remainder of 2012

Expansion projects

Constitution Pipeline

In April 2012, we began the FERC pre-filing process for a new interstate gas pipeline project. We currently own a 75 percent interest in the project and will be the operator. The new 120-mile Constitution Pipeline will connect our gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems. The total cost of the project is estimated to be $748 million. We plan to place the project into service in March 2015, with an expected capacity of 650 thousand dekatherms per day (Mdth/d). The pipeline is fully subscribed with two shippers. We expect to file a FERC application in January 2013.

Mid-South

In August 2011, we received approval from the FERC to upgrade compressor facilities and expand our existing natural gas transmission system from Alabama to markets as far north as North Carolina. The cost of the project is estimated to be $205 million. We placed the first phase of the project into service in September 2012, which increased capacity by 95 Mdth/d. We plan to place the second phase of the project into service in June 2013, which will increase capacity by an additional 130 Mdth/d.

Mid-Atlantic Connector

In July 2011, we received approval from the FERC to expand our existing natural gas transmission system from North Carolina to markets as far downstream as Maryland. The cost of the project is estimated to be $55 million and is expected to increase capacity by 142 Mdth/d. We plan to place the project into service in November 2012.

Northeast Supply Link

In December 2011, we filed an application with the FERC to expand our existing natural gas transmission system from the Marcellus Shale production region on the Leidy Line to various delivery points in New York and New Jersey. The cost of the project is estimated to be $341 million and is expected to increase capacity by 250 Mdth/d. We plan to place the project into service in November 2013.

Table of Contents

Management s Discussion and Analysis (Continued)

Eminence Storage Field Leak

On December 28, 2010, we detected a leak in one of the seven underground natural gas storage caverns at our Eminence Storage Field in Mississippi. Due to the leak and related damage to the well at an adjacent cavern, both caverns are out of service. In addition, two other caverns at the field, which were constructed at or about the same time as those caverns, have experienced operating problems, and we have determined that they should also be retired. The event has not affected the performance of our obligations under our service agreements with our customers.

In September 2011, we filed an application with the FERC seeking authorization to abandon these four caverns. We estimate the total abandonment costs, which will be capital in nature, will be approximately $92 million, which is expected to be spent through the end of 2013. As of September 30, 2012, we have incurred approximately $62 million in cumulative abandonment costs. This estimate is subject to change as work progresses and additional information becomes known. Management considers these costs to be prudent costs incurred in the abandonment of these caverns and expects to recover these costs, net of insurance proceeds, in future rate filings. To the extent available, the abandonment costs will be funded from the ARO Trust. (See Note 8 of Notes to Consolidated Financial Statements.)

Filing of Rate Cases

On August 31, 2012, Transco filed a general rate case with the FERC for an overall increase in rates. In September 2012, with the exception of certain rates that reflected a rate decrease, the FERC accepted and suspended our general rate filing to be effective March 1, 2013, subject to refund and the outcome of a hearing. The specific rates that reflected a rate decrease were accepted, without suspension, to be effective October 1, 2012 and will not be subject to refund. The impact of these specific new rates that became effective October 1, 2012 is expected to reduce revenues by approximately $4 million for the period from October 1, 2012 until the remaining rates that are currently suspended become effective on March 1, 2013.

During the first quarter of 2012, Northwest Pipeline filed a Stipulation and Settlement Agreement with the FERC for an increase in their rates. Northwest Pipeline received FERC approval during the second quarter of 2012. The new rates, which as filed are 7.4 percent higher than current rates, will become effective January 1, 2013.

Period-Over-Period Operating Results

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
	(Millions)		(Millions)	
Segment revenues	$ 412	$ 429	$ 1,233	$ 1,252
Segment profit	$ 155	$ 170	$ 482	$ 497

Three months ended September 30, 2012 vs. three months ended September 30, 2011

Segment revenues decreased $17 million, or 4 percent, primarily due to $21 million lower system management gas sales (offset in *costs and operating expenses*). This decrease is partially offset by a $5 million increase in transportation revenues associated with expansion projects placed in service in 2011 and 2012.

Segment costs and expenses decreased less than $1 million, or 1 percent, primarily due to $21 million lower system management gas costs (offset in *segment revenues)* and $5 million lower operations and maintenance expenses related to the Eminence Storage Facility leak. These decreases are partially offset by a $12 million increase in pipeline maintenance expenses, a $7 million increase in employee related expenses, and a $6 million increase in selling, general and administrative expenses.

Segment profit decreased primarily due to the previously described changes.

Management s Discussion and Analysis (Continued)

Nine months ended September 30, 2012 vs. nine months ended September 30, 2011

Segment revenues decreased $19 million, or 2 percent, primarily due to $48 million lower system management gas sales (offset in *costs and operating expenses*) and $4 million lower sales of base gas from Hester Storage Field. These decreases are partially offset by a $31 million increase in transportation revenues associated with expansion projects placed in service in 2011 and 2012.

Segment costs and expenses increased $8 million, or 1 percent, primarily due to a $15 million increase in project feasibility costs, a $12 million increase in employee related expenses, a $10 million increase in pipeline maintenance expense, a $9 million increase in selling, general and administrative expenses, a $5 million increase in depreciation and amortization, the absence of the $4 million gain of Hester base gas sales recorded in 2011, and the absence of a $10 million first-quarter 2011 reversal of project feasibility costs from expense to capital, associated with an expansion project, upon determining that the related project was probable of development. These increases were partially offset by $48 million lower system management gas costs (offset in *segment revenues*) and $11 million lower operations and maintenance expenses related to the Eminence Storage Facility leak.

Segment profit decreased primarily due to the previously described changes partially offset by a $12 million increase in equity earnings primarily due to the acquisition of an additional 24.5 percent interest in Gulfstream in May 2011.

Midstream Gas & Liquids

Overview of Nine Months Ended September 30, 2012

Midstream s ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers.

Significant events during 2012 include the following:

Gulf Olefins production facilities acquisition

In October 2012, we agreed to purchase Williams 83.3 percent undivided interest and operatorship of the olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf region. The acquisition is expected to bring more certainty to cash flows that are currently exposed to volatile ethane prices by shifting the commodity price exposure to ethylene. Located south of Baton Rouge, Louisiana, the Geismar facility is a light-end NGL cracker with current volumes of 39,000 barrels per day (bpd) of ethane and 3,000 bpd of propane and annual production of 1.35 billion pounds of ethylene. With the benefit of an expansion under way and scheduled for completion by late 2013, the facility s annual ethylene production capacity will grow by 600 million pounds to 1.95 billion pounds. Since the owner of the remaining ownership interest in the facility is not participating in the expansion, our overall undivided interest following the expansion will be approximately 88 percent. Along with ethane, propane and ethylene, the Geismar facility also produces propylene, butadiene, and debutanized aromatic concentrate (DAC). This transaction is expected to close in November 2012.

Caiman Acquisition

In April 2012, we completed the Caiman Acquisition for consideration valued at approximately $2.3 billion. The transition of operations is nearly complete.

The acquisition provides us with a significant footprint and growth potential in the natural gas liquids-rich Ohio River Valley area of the Marcellus Shale. The existing physical assets that we acquired include a gathering system, two processing facilities and a fractionator located in northern West Virginia and establish our new Ohio Valley Midstream business. In addition to the acquisition cost, we are committing a large portion of our planned 2012 capital expenditures for expansions to the gathering system, processing facilities, and fractionator, which are currently under construction. NGL pipelines are also planned. The assets are anchored by long-term contracted commitments, including 236,000 dedicated gathering acres from 10 producers in West Virginia, Ohio, and Pennsylvania.

31

Table of Contents

Management s Discussion and Analysis (Continued)

The Fort Beeler plant complex has 320 million cubic feet per day (MMcf/d) of cryogenic processing capacity currently available with another 200 MMcf/d expected to be in service at the end of 2012. The Moundsville fractionator is expected to be in service by the end of the year with approximately 13 thousand barrels per day (Mbbls/d) of NGL handling capacity. An NGL pipeline, connecting the Fort Beeler plant to the Moundsville fractionator, is in the final stages of completion.

Utica Shale infrastructure project

In July 2012, we completed an agreement with Caiman Energy, LLC and others to develop midstream infrastructure serving oil and natural gas producers in the Utica Shale, primarily in Ohio and northwest Pennsylvania. The parties anticipate investing approximately $800 million, over the next several years, to develop natural gas gathering and processing and the associated liquids infrastructure, of which our share is expected to be approximately $380 million.

Susquehanna Supply Hub, northeastern Pennsylvania

In February 2012, we completed the Laser Acquisition for $325 million in cash, net of cash acquired in the transaction and subject to certain closing adjustments, and 7,531,381 of our common units valued at $441 million. The gathering system is comprised of 33 miles of 16-inch natural gas pipeline and associated gathering facilities in Susquehanna County, Pennsylvania, as well as 10 miles of gathering pipeline in southern New York. The acquisition is supported by existing long-term gathering agreements that provide acreage dedications and volume commitments.

Our Springville pipeline was placed into service in January 2012, allowing us to deliver approximately 300 MMcf/d into the Transco pipeline. This new take-away capacity allows full use of approximately 650 MMcf/d of capacity from various compression and dehydration expansion projects to our gathering business in northeastern Pennsylvania s Marcellus Shale which we acquired at the end of 2010. In conjunction with a long-term agreement with a significant producer, we are operating the 33-mile, 24-inch diameter natural gas gathering pipeline, connecting a portion of our gathering assets into the Transco pipeline. Expansions to the Springville compression facilities were completed in the third quarter of 2012 to increase the capacity to approximately 625 MMcf/d.

As production in the Marcellus increases and expansion projects are completed, the Susquehanna Supply Hub is expected to reach a natural gas take away capacity of 3 billion cubic feet per day (Bcf/d) by 2015, including capacity contributions from the Constitution Pipeline associated with our Gas Pipeline segment.

Volume impacts in the third quarter

Our NGL equity sales volumes for the third quarter of 2012 were modestly impacted by maintenance on the Overland Pass Pipeline for approximately 5 days. As a result of the NGL pipeline maintenance, NGL takeaway capacity from our western plants on the Overland Pass Pipeline was reduced, which forced our western plants to reduce NGL recoveries.

In the Gulf Coast, our Mobile Bay plant was shut down for 10 days due to Hurricane Isaac. The plant and offshore platforms were evacuated during the storm. Afterwards, the plant remained shut down due to flooding issues on a third-party pipeline limiting the NGL takeaway capacity. In addition, production into Devils Tower was shut-in for various time periods due to third-party hurricane related issues. These events related to Hurricane Isaac did not have a material impact to our overall NGL production or NGL equity sales.

Volatile commodity prices

Driven primarily by a sharp decline in NGL prices during the second quarter of 2012, followed by increasing natural gas prices in the third quarter of 2012, average per-unit NGL margins have declined during the first nine months of 2012 and were approximately 17 percent lower in the first nine months of 2012 than in the same period of 2011. Key factors in the NGL market weakness have been high propane inventories caused by the extremely warm winter and the effect of the propane oversupply on ethane inventories and pricing. Despite an increase in natural gas prices during the third quarter of 2012, we have benefited from lower natural gas prices in the first nine months of 2012 than in the same period of 2011, driven by abundant natural gas supplies.

NGL margins are defined as NGL revenues less any applicable British thermal unit (BTU) replacement cost, plant fuel, and third-party transportation and fractionation. Per-unit NGL margins are calculated based on sales of our own equity volumes at the processing plants. Our equity volumes include NGLs where we own the rights to the value from NGLs recovered at our plants under both keep-whole processing agreements, where we have the obligation to replace the lost heating value with natural gas, and percent-of-liquids agreements whereby we receive a portion of the extracted liquids with no obligation to replace the lost heating value.

Outlook for the Remainder of 2012

The following factors could impact our business in 2012.

Commodity price changes

We expect our average per-unit NGL margins to improve from third quarter 2012 levels such that our full year 2012 margins are expected to be comparable to our rolling five-year average per-unit NGL margins, but lower than 2011. NGL price changes have historically tracked somewhat with changes in the price of

Table of Contents

crude oil, although NGL, crude, and natural gas prices are highly volatile, difficult to predict, and are often not highly correlated. NGL margins are highly dependent upon continued demand within the global economy. However, NGL products are currently the preferred feedstock for ethylene and propylene production, which has been shifting away from the more expensive crude-based feedstocks. Bolstered by abundant long-term domestic natural gas supplies, we expect to benefit from these dynamics in the broader global petrochemical markets.

As part of our efforts to manage commodity price risks on an enterprise basis, we continue to evaluate our commodity hedging strategies. To reduce the exposure to changes in market prices, we have entered into NGL swap agreements to fix the prices of approximately 12 percent to 14 percent of our anticipated NGL sales volumes and an approximate corresponding portion of anticipated shrink natural gas requirements for the remainder of 2012. The combined impact of these energy commodity derivatives, designated as cash flow hedges will ensure a margin on the hedged volumes of $61 million. The following table presents our energy commodity hedging instruments as of September 30, 2012.

Table of Contents

Management s Discussion and Analysis (Continued)

Designated as hedging instruments:	Period	Volumes Hedged	Weighted Average Hedge Price (per gallon)
NGL sales - propane (million gallons)	Oct - Dec 2012	8.2	$ 1.31
NGL sales - isobutane (million gallons)	Oct - Dec 2012	7.6	$ 1.95
NGL sales - normal butane (million gallons)	Oct - Dec 2012	7.6	$ 1.82
NGL sales - natural gasoline (million gallons)	Oct - Dec 2012	13.9	$ 2.32
			(per MMbtu)
Natural gas purchases (Tbtu)	Oct - Dec 2012	3.9	$ 2.62

Gathering, processing, and NGL sales volumes

The growth of natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities, which are influenced by natural gas prices.

In our onshore businesses, we anticipate significant growth in our natural gas gathering volumes as our infrastructure grows to support drilling activities in the Marcellus Shale region. We anticipate equity NGL volumes in 2012 to be comparable to 2011. Sustained low natural gas prices could discourage producer drilling activities in certain of our onshore areas and unfavorably impact the supply of natural gas available to gather and process in 2013 and the long term.

In our businesses in the Gulf Coast, we expect higher gas gathering, processing, and crude transportation volumes compared to the latter half of 2011, as production flowing through our Perdido Norte pipelines becomes consistent and other in-process drilling is completed. In the Gulf Coast, our customers drilling activities are primarily focused on crude oil economics, rather than natural gas. We have not experienced, and do not anticipate an overall significant decline in volumes due to reduced drilling activities.

We anticipate higher general and administrative, operating, and depreciation expense supporting our growing operations in the Marcellus Shale area, Piceance basin, and western Gulf of Mexico.

Expansion Projects

We expect to invest total capital of $7.4 billion to $7.6 billion in 2012. We plan to pursue expansion and growth opportunities in the Marcellus Shale region, Gulf of Mexico, and Piceance basin.

Our ongoing major expansion projects include the following:

Expansion of the Susquehanna Supply Hub in northeastern Pennsylvania, as previously discussed.

As previously discussed, expansions currently under construction to our natural gas gathering system, processing facilities and fractionator in our Ohio Valley Midstream business of the Marcellus Shale.

Expansions to our gathering system through capital to be invested within our Laurel Mountain equity investment, also in the Marcellus Shale region. The Shamrock compressor station, currently providing 60 MMcf/d of capacity, is expandable to 350 MMcf/d and will likely be the largest central delivery point out of the Laurel Mountain system. Our equity investee is progressing on further expansions to the Shamrock compressor station and other additions to the gathering infrastructure in 2012.

We will design, construct, and install our Gulfstar FPS , a spar-based floating production system that utilizes a standard design approach with a capacity of 60 Mbbls/d of oil, up to 200 MMcf/d of natural gas, and the capability to provide seawater injection services. We expect Gulfstar FPS to be capable of serving as a central host facility for other deepwater prospects in the area. Construction is underway and the project is expected to be in service in 2014. We may consider a partner for this project.

Table of Contents

Management s Discussion and Analysis (Continued)

In conjunction with a basin-wide agreement for all gathering and processing services provided by us to WPX in the Piceance basin, we plan to construct a 350 MMcf/d cryogenic natural gas processing plant. The Parachute TXP I plant is expected to be in service in 2014.

Our equity investee which we operate, Discovery, plans to construct, own, and operate a new 215-mile, 20-inch deepwater lateral pipeline from a third-party floating production facility located in the Keathley Canyon Block in the central deepwater Gulf of Mexico. Discovery has signed long-term agreements with anchor customers for natural gas gathering and processing services for production from those fields. The Keathley Canyon Connector lateral will originate from a third-party floating production facility in the southeast portion of the Keathley Canyon area and will connect to Discovery s existing 30-inch offshore natural gas transmission system. The lateral pipeline is estimated to have the capacity to flow more than 400 MMcf/d and will accommodate the tie-in of other deepwater prospects. Pre-construction activities have begun, the pipeline is expected to be laid in 2013, and is planned to be in-service in mid-2014.

Through our equity investment in Overland Pass Pipeline Company LLC (OPPL), we are participating in the construction of a pipeline connection and capacity expansions, expected to be complete in early 2013, to increase the pipeline s capacity to the maximum of 255 Mbbls/d, to accommodate new volumes coming from the Bakken Shale in the Williston basin.

Period-Over-Period Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
			(Millions)	
Segment revenues	$ 1,115	$ 1,244	$ 3,562	$ 3,671
Segment profit	$ 218	$ 301	$ 718	$ 882

Three months ended September 30, 2012 vs. three months ended September 30, 2011

The decrease in *segment revenues* includes:

A $99 million decrease in revenues from our equity NGLs primarily reflecting a decrease of $121 million associated with an overall 36 percent decrease in average NGL per-unit sales prices. Average ethane and non-ethane per-unit prices decreased by 60 percent and 23 percent, respectively.

A $51 million decrease in marketing revenues primarily due to lower NGL prices, partially offset by higher NGL and crude volumes, as well as new volumes from natural gas marketing activities. These changes are offset by similar changes in marketing purchases and resulted in insignificant margins in the third quarter of 2012.

A $27 million increase in fee revenues primarily due to higher volumes in the Marcellus Shale, including new volumes on our recently acquired natural gas gathering and processing assets in our Ohio Valley Midstream and Susquehanna Supply Hub businesses.

Table of Contents

Management s Discussion and Analysis (Continued)

Segment costs and expenses decreased $58 million, or 6 percent, including:

- A $57 million decrease in marketing purchases primarily due to lower average NGL prices, partially offset by higher NGL and crude volumes, as well as new volumes from natural gas marketing activities.
- A $32 million decrease in costs associated with our equity NGLs primarily due to a 35 percent decrease in average natural gas prices.
- A $23 million increase in operating costs primarily due to higher depreciation and amortization of assets and intangibles acquired in 2012 and increased depreciation on certain assets in the Gulf Coast region resulting from a change in the estimated useful lives.
- A $15 million increase in general and administrative expenses including increases in employee-related expenses and information technology costs driven by general growth within our business operations, along with acquisition and transition-related costs.

The decrease in Midstream s *segment profit* reflects the previously described changes in *segment revenues* and *segment costs and expenses*. A more detailed analysis of the *segment profit* of certain Midstream operations is presented as follows.

The decrease in Midstream s *segment profit* includes:

- A $67 million decrease in NGL margins driven primarily by commodity price changes including lower NGL prices, partially offset by lower natural gas prices.
- A $23 million increase in operating costs as previously discussed.
- A $15 million increase in general and administrative expenses as previously discussed.
- A $12 million decrease in equity earnings primarily due to $5 million lower Discovery equity earnings, primarily due to lower NGL margins and volumes, and $5 million lower Aux Sable equity earnings, primarily due to lower NGL margins.
- A $27 million increase in fee revenues as previously discussed.

Nine months ended September 30, 2012 vs. nine months ended September 30, 2011

The decrease in *segment revenues* includes:

- A $210 million decrease in revenues from our equity NGLs primarily reflecting a decrease of $225 million associated with an overall 24 percent decrease in average NGL per-unit sales prices. Average ethane and non-ethane per-unit prices decreased by 41 percent and 13 percent, respectively.

A $110 million increase in fee revenues primarily due to higher volumes in the Marcellus Shale, including new volumes on our recently acquired gathering and processing assets in our Ohio Valley Midstream and Susquehanna Supply Hub businesses; higher volumes in the western deepwater Gulf of Mexico, including higher volumes on our Perdido Norte natural gas and oil pipelines; and higher volumes in the Piceance basin.

Marketing revenues are comparable primarily due to a significant decrease in NGL prices, offset by higher NGL and crude volumes, as well as new volumes from natural gas marketing activities.

Table of Contents

Management s Discussion and Analysis (Continued)

Segment costs and expenses increased $29 million, or 1 percent, including:

A $53 million increase in operating costs including higher depreciation and amortization of assets and intangibles, along with maintenance costs associated with assets acquired in 2012 and higher turbine and engine maintenance expenses, partially offset by lower costs in our Four Corners area related to the consolidation of certain operations.

A $51 million increase in general and administrative expenses including $22 million of Caiman and Laser acquisition and transition-related costs, as well as increases in information technology and employee-related expenses driven by general growth within our business operations.

A $45 million increase in marketing purchases primarily due to higher NGL and crude volumes, as well as new volumes from natural gas marketing activities, partially offset by significantly lower average NGL prices. The changes in natural gas marketing purchases are offset by similar changes in natural gas marketing revenues and resulted in insignificant margins in 2012.

A $114 million decrease in costs associated with our equity NGLs primarily due to a 36 percent decrease in average natural gas prices.

The decrease in Midstream s *segment profit* reflects the previously described changes in *segment revenues* and *segment costs and expenses*. A more detailed analysis of the *segment profit* of certain Midstream operations is presented as follows.

The decrease in Midstream s *segment profit* includes:

A $96 million decrease in NGL margins driven primarily by commodity price changes including lower NGL prices, partially offset by lower natural gas prices.

A $53 million increase in operating costs as previously discussed.

A $51 million increase in general and administrative expenses as previously discussed.

A $48 million decrease in margins related to the marketing of NGLs primarily due to the impact of a significant and rapid decline in NGL prices during the second quarter of 2012 while product was in transit compared to periods of increasing prices during 2011.

A $26 million decrease in equity earnings primarily due to $11 million lower Laurel Mountain equity earnings driven by higher operating costs, including depreciation, and lower gathering rates indexed to natural gas prices, partially offset by higher gathered volumes; $8 million lower Aux Sable equity earnings primarily due to lower NGL margins; and $8 million lower Discovery equity earnings primarily due to lower NGL margins and volumes.

A $110 million increase in fee revenues as previously discussed.

Table of Contents

Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition and Liquidity

Outlook

The sharp decline in NGL margins during the second quarter of 2012 has reduced the expected level of operating cash flows from certain of our businesses in 2012. The downward trend of per-unit NGL margins has leveled off during third quarter 2012 and we anticipate a modest level of improvement through the end of the year. Although our cash flows are impacted by fluctuations in energy commodity prices, further reduction in expected energy commodity prices would be somewhat mitigated by certain of our cash flow streams that are not directly impacted by short-term commodity price movements, as follows:

- Firm demand and capacity reservation transportation revenues under long-term contracts at Gas Pipeline;
- Fee-based revenues from certain gathering and processing services at Midstream.

Over the longer-term, we expect the influence of short-term changes in commodity prices on our cash flows to diminish as we transition to an overall business mix that is increasingly fee-based.

We continue to believe we have, or have access to, the financial resources and liquidity necessary to meet our requirements for working capital, capital and investment expenditures, unitholder distributions and debt service payments while maintaining a sufficient level of liquidity. In particular, we note the following for 2012:

- We increased our per-unit quarterly distribution with respect to the third quarter of 2012 from $0.7925 to $0.8075. We expect to increase quarterly limited partner cash distributions by approximately 8 percent in 2012.
- We expect to fund capital and investment expenditures, debt service payments, distributions to unitholders and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, cash proceeds from common unit and/or long-term debt issuances and utilization of our revolver as needed. Based on a range of market assumptions, we currently estimate our cash flow from operations will be between $1.725 billion and $1.875 billion in 2012. In addition, we retain the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.
- In October 2012, we agreed to purchase Williams 83.3 percent undivided interest and operatorship in an olefins-production facility located in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf region for total consideration valued at approximately $2.364 billion, including 42,778,812 limited partner units, $25 million in cash, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest. The acquisition is expected to bring more certainty to cash flows that are currently exposed to volatile ethane prices by shifting the commodity price exposure to ethylene. The transaction is expected to close in November 2012.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2012. Our internal and external sources of liquidity include:

Cash and cash equivalents on hand;

Cash generated from operations, including cash distributions from our equity-method investees;

Cash proceeds from offerings of our common units and/or long-term debt;

Use of our revolver, as needed and available.

We anticipate our more significant uses of cash to be:

- Maintenance and expansion capital expenditures;
- Payment of debt maturities (pursuant to expected issuances of new long-term debt);
- Contributions to our equity-method investees to fund their expansion capital expenditures;
- Interest on our long-term debt;
- Quarterly distributions to our unitholders and/or general partner.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations;
- Limited availability of capital due to a change in our financial condition, interest rates, market or industry conditions;
- Sustained reductions in energy commodity margins from expected 2012 levels;
- Physical damages to facilities, especially damage to offshore facilities by named windstorms.

Available Liquidity	**September 30, 2012 (Millions)**
Cash and cash equivalents	$ 368
Capacity available under our $2.4 billion five-year revolver (expires June 3, 2016) (1)	2,400
	$ 2,768

(1) In September 2012, we amended our existing $2 billion five-year revolver to increase the aggregate commitments by $400 million. The full amount of the revolver is available to us, to the extent not otherwise utilized by Transco and Northwest Pipeline, and may, under certain conditions, be increased by up to an additional $400 million. Transco and Northwest Pipeline are each able to borrow up to $400 million under the revolver to the extent not otherwise utilized by the other co-borrowers. At September 30, 2012, we are in compliance with the financial covenants associated with this revolver. (See Note 6 of Notes to Consolidated Financial Statements.)

Shelf Registration

In February 2012, we filed a shelf registration statement as a well-known seasoned issuer that allows us to issue an unlimited amount of registered debt and limited partnership unit securities.

Distributions from Equity Method Investees

Our equity method investees organizational documents require distribution of their available cash to their members on a quarterly basis. In each case, available cash is reduced, in part, by reserves appropriate for operating their respective businesses. Our more significant equity method investees include: Aux Sable, Discovery, Gulfstream, Laurel Mountain, and OPPL.

Table of Contents

Management s Discussion and Analysis (Continued)

Debt Offerings

In August 2012, we completed a public offering of $750 million of our 3.35 percent senior unsecured notes due in 2022. We used the $745 million net proceeds to repay outstanding borrowings under our revolver and for general partnership purposes.

In July 2012, Transco received net proceeds of $395 million from the issuance of $400 million of 4.45 percent senior unsecured notes due in 2042. These proceeds were used to repay Transco s $325 million 8.875 percent notes and for general corporate purposes, including capital expenditures.

Equity Offerings

In August 2012, we completed an equity issuance of 8,500,000 common units representing limited partner interests in us at a price of $51.43 per unit. Subsequently, we sold an additional 1,275,000 common units for $51.43 per unit to the underwriters upon the underwriters exercise of their option to purchase additional common units. The net proceeds of $488 million were used to repay outstanding borrowings under our revolver and for general partnership purposes.

In April 2012, we completed an equity issuance of 10,000,000 common units representing limited partner interests in us at a price of $54.56 per unit. Subsequently, we sold an additional 973,368 common units for $54.56 per unit to the underwriters upon the underwriters exercise of their option to purchase additional common units. The net proceeds of $581 million were used for general partnership purposes, including the funding of a portion of the cash purchase price of the Caiman Acquisition.

In April 2012, we also issued 16,360,133 common units to Williams for $1 billion, which was used to fund a portion of the cash purchase price of the Caiman Acquisition.

In January 2012, we completed an equity issuance of 7,000,000 common units representing limited partner interests in us at a price of $62.81 per unit. In February 2012, we sold an additional 1,050,000 common units for $62.81 per unit to the underwriters upon the underwriters exercise of their option to purchase additional common units. The net proceeds of $490 million were used to fund capital expenditures and for general partnership purposes.

Additionally, we issued equity to the sellers for acquisitions as discussed below.

Acquisitions

In April 2012, we completed the Caiman Acquisition in exchange for aggregate consideration of $1.72 billion in cash, net of purchase price adjustments, and 11,779,296 of our common units.

In February 2012, we completed the Laser Acquisition in exchange for $325 million in cash, net of cash acquired in the transaction, and 7,531,381 of our common units.

Credit Ratings

The table below presents our current credit ratings and outlook on our senior unsecured long-term debt.

Rating Agency	Date of Last Change	Outlook	Senior Unsecured Debt Rating
Standard & Poor s	March 5, 2012	Stable	BBB
Moody s Investors Service	February 27, 2012	Stable	Baa2

Fitch Ratings	February 9, 2012	Positive	BBB-

Management s Discussion and Analysis (Continued)

With respect to Standard and Poor s, a rating of BBB or above indicates an investment grade rating. A rating below BBB indicates that the security has significant speculative characteristics. A BB rating indicates that Standard and Poor s believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard and Poor s may modify its ratings with a + or a - sign to show the obligor s relative standing within a major rating category.

With respect to Moody s, a rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. The 1 , 2 , and 3 modifiers show the relative standing within a major category. A 1 indicates that an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 indicates a ranking at the lower end of the category.

With respect to Fitch, a rating of BBB or above indicates an investment grade rating. A rating below BBB is considered speculative grade. Fitch may add a + or a - sign to show the obligor s relative standing within a major rating category.

Credit rating agencies perform independent analyses when assigning credit ratings. No assurance can be given that the credit rating agencies will continue to assign us investment grade ratings even if we meet or exceed their current criteria for investment grade ratios. A downgrade of our credit rating might increase our future cost of borrowing and would require us to post additional collateral with third parties, negatively impacting our available liquidity. As of September 30, 2012, we estimate that a downgrade to a rating below investment grade could require us to post up to $400 million in additional collateral with third parties.

Capital Expenditures

Each of our businesses is capital-intensive, requiring investment to upgrade or enhance existing operations and comply with safety and environmental regulations. The capital requirements of these businesses consist primarily of:

Maintenance capital expenditures, which are generally not discretionary, including (1) capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives, (2) expenditures which are mandatory and/or essential to comply with laws and regulations and maintain the reliability of our operations, and (3) certain well connection expenditures.

Expansion capital expenditures, which are generally more discretionary than maintenance capital expenditures, including (1) expenditures to acquire additional assets to grow our business, to expand and upgrade plant or pipeline capacity and to construct new plants, pipelines and storage facilities and (2) well connection expenditures which are not classified as maintenance expenditures.

The following table provides summary information related to our actual and expected capital expenditures, purchases of businesses, and contributions to equity method investments for 2012. The amounts presented for expansion do not include equity issued in association with the Laser and Caiman Acquisitions, and the Geismar dropdown of approximately $3.5 billion. Included are gross increases to our property, plant, and equipment, including changes related to accounts payable and accrued liabilities:

	Maintenance		Expansion		Total	
Segment	2012 Estimate	Nine Months Ended September 30, 2012	2012 Estimate	Nine Months Ended September 30, 2012	2012 Estimate	Nine Months Ended September 30, 2012
			(Millions)			
Gas Pipeline	$ 315-365	$ 230	$ 325-350	$ 221	$ 640-715	$ 451
Midstream	110-130	72	3,755-3935	3,207	3,865-4,065	3,279
Total	$ 425-495	$ 302	$ 4,080-4,285	$ 3,428	$ 4,505-4,780	$ 3,730

42

Table of Contents

Management s Discussion and Analysis (Continued)

See Results of Operations Segments, Gas Pipeline and Midstream for discussions describing the general nature of these expenditures.

Cash Distributions to Unitholders

We have paid quarterly distributions to unitholders and our general partner after every quarter since our initial public offering on August 23, 2005. We have increased our quarterly distribution from $0.7925 to $0.8075 per unit, which resulted in a third quarter 2012 distribution of approximately $394 million that will be paid on November 9, 2012, to the general and limited partners of record at the close of business on November 2, 2012. (See Note 3 of Notes to Consolidated Financial Statements).

Williams has agreed to temporarily waive its incentive distribution rights related to the common units issued to Williams and the seller of Caiman Eastern Midstream, LLC, in connection with our acquisition of that entity. The incentive distribution rights waived relative to distributions paid in 2012 will be $24 million.

Sources (Uses) of Cash

	Nine months ended September 30, 2012	2011
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 1,330	$ 1,517
Financing activities	2,414	(624)
Investing activities	(3,539)	(937)
Increase (decrease) in cash and cash equivalents	$ 205	$ (44)

Operating activities

Net cash provided by operating activities for the nine months ended September 30, 2012, decreased $187 million compared to the nine months ended September 30, 2011, due primarily to lower operating income.

Financing activities

Significant transactions include:

- $460 million received in revolver borrowings during third quarter 2012 for general partnership purposes, including capital expenditures;
- $745 million net proceeds received from our August 2012 public offering of $750 million of senior unsecured notes due in 2022;
- $395 million net proceeds received from Transco s July 2012 issuance of $400 million of senior unsecured notes due in 2042;
- $488 million received from our third quarter 2012 equity offering;

$581 million received from our second quarter 2012 equity offering;

$1 billion received from Williams for common units issued, used for the funding of a portion of the cash purchase price of the Caiman Acquisition;

- $490 million received from our first quarter 2012 equity offering;
- $500 million received in borrowings from our previous $2 billion revolver for capital expenditures and general partnership purposes during second quarter 2012;
- $805 million of revolver borrowings paid during third quarter 2012;
- $325 million paid to retire Transco s 8.875 percent notes upon their maturity on July 15, 2012;
- $155 million of revolver borrowings paid during second quarter 2012;
- $1,046 million and $830 million related to quarterly cash distributions paid to limited partner unitholders and our general partner in 2012 and 2011, respectively;
- $375 million received from Transco s issuance of senior unsecured notes in August 2011;
- $300 million paid to retire Transco s senior unsecured notes that matured in August 2011;
- $300 million received in revolver borrowings from our previous $1.75 billion unsecured credit facility used to acquire a 24.5 percent interest in Gulfstream from Williams in May 2011. This obligation was transferred to our previous $2 billion credit facility at its inception in June 2011;
- $150 million paid to retire senior unsecured notes that matured in June 2011;
- $123 million distributed to Williams related to the excess purchase price over the contributed basis of Gulfstream in May 2011.

Investing activities

Significant transactions include:

- $1.72 billion paid, net of purchase price adjustments, for the Caiman Acquisition in April 2012;
- $325 million paid, net of cash acquired in the transaction, for the Laser Acquisition in March 2012;
- Capital expenditures in 2012 and 2011 totaled $1,288 million and $598 million, respectively;

We contributed $282 million and $140 million to our equity method investments in 2012 and 2011, respectively;

$174 million related to our acquisition of a 24.5 percent interest in Gulfstream from Williams in May 2011.

Off-Balance Sheet Arrangements and Guarantees of Debt or Other Commitments

We have various other guarantees and commitments which are disclosed in Notes 8 and 10 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Table of Contents

Item 3

Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio and has not materially changed during the first nine months of 2012.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of NGLs and natural gas, as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts, and limited proprietary trading activities. Our management of the risks associated with these market fluctuations includes maintaining a conservative capital structure and significant liquidity, as well as using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. (See Note 9 of Notes to Consolidated Financial Statements.)

We measure the risk in our portfolio using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolio. Value-at-risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolio. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolio will not exceed the value-at-risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value-at-risk separately for these two categories. Contracts designated as normal purchases or sales and nonderivative energy contracts have been excluded from our estimation of value-at-risk.

Trading

Our limited trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net asset of less than $0.1 million at September 30, 2012 and December 31, 2011. The value-at-risk for contracts held for trading purposes was zero at September 30, 2012, and less than $0.1 million at December 31, 2011.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from natural gas purchase and NGL sale activities. The fair value of our nontrading derivatives was a net asset of $16 million at September 30, 2012, and a net asset of $1 million at December 31, 2011. The value-at-risk for derivative contracts held for nontrading purposes was $1 million at September 30, 2012, and zero at December 31, 2011.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges. Of the total fair value of nontrading derivatives, cash flow hedges had a net asset value of $15 million at September 30, 2012, and zero at December 31, 2011. Though these contracts are included in our value-at-risk calculation, any changes in the fair value of the effective portion of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Table of Contents

Item 4

Controls and Procedures

Our management, including our general partner s Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (Disclosure Controls) or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Williams Partners L.P. have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and Internal Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our general partner s Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner s Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Third-Quarter 2012 Changes in Internal Controls

There have been no changes during the third quarter of 2012 that have materially affected, or are reasonably likely to materially affect, our Internal Controls.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Environmental

Certain reportable legal proceedings involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment are described below. While it is not possible for us to predict the final outcome of the proceedings which are still pending, we do not anticipate a material effect on our consolidated financial position if we receive an unfavorable outcome in any one or more of such proceedings.

In September 2007, the EPA requested, and our Transco subsidiary later provided, information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA s investigation of Transco s compliance with the Clean Air Act. On March 28, 2008, the EPA issued notices of violation alleging violations of Clean Air Act requirements at these compressor stations. Transco met with the EPA in May 2008 and submitted a response denying the allegations in June 2008. In May 2011, Transco provided additional information to the EPA pertaining to these compressor stations in response to a request they had made in February 2011. In August 2010, the EPA requested, and Transco provided, similar information for a compressor station in Maryland.

In September 2011, the Colorado Department of Public Health and Environment issued a Notice of Violation for alleged violations of the Colorado Clean Water Act related to excavation work being done for our Crawford Trail Pipeline. In August 2012, we settled with the agency for $275,000.

Other

The additional information called for by this item is provided in Note 10 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2011, includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed, except as set forth below:

The existence and potential sale of common units issued to third parties in our acquisitions may adversely affect the price of our common units.

We have issued 7,531,381 additional common units to Delphi Midstream Partners, LLC in connection with the Laser Acquisition, which are subject to certain trading restrictions that expire over time beginning April 17, 2012. We have issued 11,779,296 additional common units to Caiman Energy, LLC in connection with the Caiman Acquisition, which are subject to restriction on transfer for a period of 18 months without our consent. We may also issue additional common units to other unaffiliated third parties in connection with future acquisitions. Sales of substantial amounts of common units by third parties, or the anticipation of such sales, could lower the market price of our common units and may make it more difficult for us to sell our equity securities in the future at a time and at a price that we deem appropriate.

Item 6. Exhibits

Exhibit No.	Description
Exhibit 3.1	Certificate of Limited Partnership of Williams Partners L.P. (filed on May 2, 2005 as Exhibit 3.1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.2	Certificate of Formation of Williams Partners GP LLC (filed on May 2, 2005 as Exhibit 3.3 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.3	Amended and Restated Agreement of Limited Partnership of Williams Partners L.P. (including form of common unit certificate), as amended by Amendments Nos. 1, 2, 3, 4, 5, 6, 7, and 8 (filed on August 2, 2012 as Exhibit 3.3 to Williams Partners L.P. s quarterly report on Form 10-Q (File No. 001-32599)) and incorporated herein by reference.
Exhibit 3.4	Amended and Restated Limited Liability Company Agreement of Williams Partners GP LLC (filed on August 26, 2005 as Exhibit 3.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.1	Third Supplemental Indenture (including Form of 3.35% Senior Notes due 2022), dated as of August 14, 2012, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on August 14, 2012 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.1	Commitment Increase and First Amendment Agreement, dated as of September 25, 2012, by and among Williams Partners L.P., Northwest Pipeline GP and Transcontinental Gas Pipe Line Company, LLC, as co-borrowers, the lenders named therein, the Issuing Banks, and Citibank N.A., as administrative agent (filed on September 27, 2012 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
*Exhibit 12	Computation of Ratio of Earnings to Fixed Charges.
*Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**Exhibit 32	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*Exhibit 101.INS	XBRL Instance Document.
*Exhibit 101.SCH	XBRL Taxonomy Extension Schema.
*Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
*Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.
*Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.
*Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Filed herewith.
** Furnished herewith.

48

Table of Contents

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

WILLIAMS PARTNERS L.P.

(Registrant)

By: Williams Partners GP LLC, its general partner

/s/ Ted T. Timmermans
Ted T. Timmermans

Vice President, Controller, and Chief Accounting Officer
(Duly Authorized Officer and Principal

Accounting Officer)

October 31, 2012

Table of Contents

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Table of Contents

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** Furnished herewith.