WILLIAMS COMPANIES INC
Form 10-Q
November 02, 2011
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2011

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 1-4174

THE WILLIAMS COMPANIES, INC.

(Exact name of registrant as specified in its charter)

DELAWARE	**73-0569878**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**
ONE WILLIAMS CENTER, TULSA, OKLAHOMA	**74172**
(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 þ 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). þ Yes ¨ No

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

Large accelerated filer þ 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 þ

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	**Outstanding at October 31, 2011**
Common Stock, $1 par value	589,411,024 Shares

Table of Contents

The Williams Companies, Inc.

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. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

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, forecasts, inte objectives, targets, planned, potential, projects, scheduled, will , or other similar expressions. These forward-looking statements are bas management s beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

Plans to separate our exploration and production business into a stand-alone, publicly traded corporation;

Amounts and nature of future capital expenditures;

Expansion and growth of our business and operations;

Financial condition and liquidity;

Business strategy;

Estimates of proved gas and oil reserves;

Reserve potential;

Development drilling potential;

Cash flow from operations or results of operations;

Seasonality of certain business segments;

Natural gas, natural gas liquids, and crude oil prices and demand.

Table of Contents

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. 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:

- Our ability to complete the separation of our exploration and production business into a stand-alone, publicly traded corporation or to complete the separation on the timeline or terms we have announced;
- Availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring, and developing future natural gas and oil reserves), market demand, volatility of prices, and the availability and cost of capital;
- Inflation, interest rates, fluctuation in foreign exchange, 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;
- Development of alternative energy sources;
- The impact of operational and development hazards;
- Costs of, changes in, or the results of laws, government regulations (including climate change regulation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation, and rate proceedings;
- Our costs and funding obligations for defined benefit pension plans and other postretirement benefit plans;
- Changes in maintenance and construction costs;
- Changes in the current geopolitical situation;
- Our exposure to the credit risk of our customers;
- 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;
- Risks associated with future weather conditions;
- Acts of terrorism;

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, 2010, and Part II, Item 1A. Risk Factors of this Form 10-Q.

Table of Contents

The Williams Companies, Inc.

Consolidated Statement of Operations

(Unaudited)

(Millions, except per-share amounts)	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Revenues:				
Williams Partners	$ 1,673	$ 1,327	$ 4,923	$ 4,217
Exploration & Production	1,022	1,005	2,992	3,063
Midstream Canada & Olefins	326	232	989	761
Other	6	6	19	17
Intercompany eliminations	(324)	(270)	(976)	(878)
Total revenues	2,703	2,300	7,947	7,180
Segment costs and expenses:				
Costs and operating expenses	2,025	1,748	5,871	5,382
Selling, general, and administrative expenses	130	122	401	356
Impairments of goodwill and long-lived assets		1,681		1,681
Other (income) expense net		(4)	2	(17)
Total segment costs and expenses	2,155	3,547	6,274	7,402
General corporate expenses	54	43	152	173
Operating income (loss):				
Williams Partners	431	347	1,278	1,079
Exploration & Production	43	(1,635)	177	(1,419)
Midstream Canada & Olefins	73	42	219	123
Other	1	(1)	(1)	(5)
General corporate expenses	(54)	(43)	(152)	(173)
Total operating income (loss)	494	(1,290)	1,521	(395)
Interest accrued	(152)	(158)	(466)	(476)
Interest capitalized	11	13	29	43
Investing income net	49	68	145	162
Early debt retirement costs				(606)
Other income (expense) net		(4)	4	(12)
Income (loss) from continuing operations before income taxes	402	(1,371)	1,233	(1,284)
Provision (benefit) for income taxes	55	(150)	194	(140)
Income (loss) from continuing operations	347	(1,221)	1,039	(1,144)
Income (loss) from discontinued operations	(5)	(5)	(16)	(6)
Net income (loss)	342	(1,226)	1,023	(1,150)
Less: Net income attributable to noncontrolling interests	70	37	203	121
Net income (loss) attributable to The Williams Companies, Inc.	$ 272	$ (1,263)	$ 820	$ (1,271)

Amounts attributable to The Williams Companies, Inc.:

Income (loss) from continuing operations	$ 277	$ (1,258)	$ 836	$ (1,265)
Income (loss) from discontinued operations	(5)	(5)	(16)	(6)
Net income (loss)	$ 272	$ (1,263)	$ 820	$ (1,271)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ .47	$ (2.15)	$ 1.42	$ (2.16)
Income (loss) from discontinued operations	(.01)	(.01)	(.03)	(.01)
Net income (loss)	$ .46	$ (2.16)	$ 1.39	$ (2.17)
Weighted-average shares (thousands)	588,950	584,744	588,082	584,365
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ .47	$ (2.15)	$ 1.40	$ (2.16)
Income (loss) from discontinued operations	(.01)	(.01)	(.03)	(.01)
Net income (loss)	$ .46	$ (2.16)	$ 1.37	$ (2.17)
Weighted-average shares (thousands)	597,550	584,744	597,250	584,365
Cash dividends declared per common share	$ .200	$ .125	$ .525	$ .360

See accompanying notes.

Table of Contents

The Williams Companies, Inc.

Consolidated Balance Sheet

(Unaudited)

(Dollars in millions, except per-share amounts)	September 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 996	$ 795
Accounts and notes receivable (net of allowance of $17 at September 30, 2011 and $15 at December 31, 2010)	1,039	859
Inventories	287	302
Derivative assets	381	400
Other current assets and deferred charges	186	174
Total current assets	2,889	2,530
Investments	1,492	1,344
Property, plant, and equipment, at cost	32,159	30,365
Accumulated depreciation, depletion, and amortization	(11,186)	(10,144)
Property, plant, and equipment net	20,973	20,221
Derivative assets	118	173
Other assets and deferred charges	674	704
Total assets	$ 26,146	$ 24,972
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,174	$ 918
Accrued liabilities	801	1,002
Derivative liabilities	103	146
Long-term debt due within one year	361	508
Total current liabilities	2,439	2,574
Long-term debt	9,024	8,600
Deferred income taxes	3,609	3,448
Derivative liabilities	73	143
Other liabilities and deferred income	1,748	1,588
Contingent liabilities and commitments (Note 12)		
Equity:		
Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 623 million shares issued at September 30, 2011 and 620 million shares issued at December 31, 2010)	623	620
Capital in excess of par value	8,368	8,269
Retained earnings (deficit)	33	(478)
Accumulated other comprehensive income (loss)	(74)	(82)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders equity	7,909	7,288

Noncontrolling interests in consolidated subsidiaries		1,344		1,331
Total equity		9,253		8,619
Total liabilities and equity	$	26,146	$	24,972

See accompanying notes.

Table of Contents

The Williams Companies, Inc.

Consolidated Statement of Changes in Equity

(Unaudited)

	Three months ended September 30,					
	2011			2010		
(Millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 7,716	$ 1,329	$ 9,045	$ 7,979	$ 1,047	$ 9,026
Comprehensive income (loss):						
Net income (loss)	272	70	342	(1,263)	37	(1,226)
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	83		83	71	(5)	66
Foreign currency translation adjustments	(66)		(66)	21		21
Pension and other postretirement benefits net	5		5	5		5
Unrealized gain (loss) on equity securities	(1)		(1)			
Total other comprehensive income (loss)	21		21	97	(5)	92
Total comprehensive income (loss)	293	70	363	(1,166)	32	(1,134)
Cash dividends common stock	(118)		(118)	(73)		(73)
Dividends and distributions to noncontrolling interests		(54)	(54)		(33)	(33)
Stock-based compensation, net of tax	17		17	12		12
Issuance of common stock from 5.5%debentures conversion				1		1
Sale of limited partner units of consolidated partnership					380	380
Changes in Williams Partners L.P. ownership interest				275	(275)	
Other	1	(1)		(3)		(3)
Ending balance	$ 7,909	$ 1,344	$ 9,253	$ 7,025	$ 1,151	$ 8,176

	Nine months ended September 30,					
	2011			2010		
(Millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 7,288	$ 1,331	$ 8,619	$ 8,447	$ 572	$ 9,019
Comprehensive income (loss):						
Net income (loss)	820	203	1,023	(1,271)	121	(1,150)
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	29		29	176	(2)	174
Foreign currency translation adjustments	(39)		(39)	11		11
Pension and other postretirement benefits net	16		16	15		15
Unrealized gain (loss) on equity securities	2		2			
Total other comprehensive income (loss)	8		8	202	(2)	200

Total comprehensive income (loss)	828	203	1,031	(1,069)	119	(950)
Cash dividends common stock	(309)		(309)	(210)		(210)
Dividends and distributions to noncontrolling interests		(159)	(159)		(99)	(99)
Stock-based compensation, net of tax	69		69	37		37
Issuance of common stock from 5.5%debentures conversion	2		2	1		1
Sale of limited partner units of consolidated partnership					380	380
Changes in Williams Partners L.P. ownership interest	30	(30)		(179)	179	
Other	1	(1)		(2)		(2)
Ending balance	$ 7,909	$ 1,344	$ 9,253	$ 7,025	$ 1,151	$ 8,176

See accompanying notes.

Table of Contents

The Williams Companies, Inc.

Consolidated Statement of Cash Flows

(Unaudited)

	Nine months ended September 30,	
(Millions)	**2011**	**2010**
OPERATING ACTIVITIES:		
Net income (loss)	$ 1,023	$ (1,150)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation, depletion, and amortization	1,202	1,101
Provision (benefit) for deferred income taxes	77	(190)
Provision for loss on investments, property and other assets	130	1,720
Amortization of stock-based awards	36	37
Early debt retirement costs		606
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	(180)	92
Inventories	15	(49)
Margin deposits and customer margin deposits payable	(26)	6
Other current assets and deferred charges	(1)	5
Accounts payable	165	(72)
Accrued liabilities	(67)	(94)
Changes in current and noncurrent derivative assets and liabilities	11	(30)
Other, including changes in noncurrent assets and liabilities	(33)	(41)
Net cash provided by operating activities	2,352	1,941
FINANCING ACTIVITIES:		
Proceeds from long-term debt	1,100	4,179
Payments of long-term debt	(824)	(3,953)
Proceeds from sale of limited partner units of consolidated partnership		380
Dividends paid	(309)	(210)
Dividends and distributions paid to noncontrolling interests	(159)	(99)
Payments for debt issuance costs	(24)	(66)
Premiums paid on early debt retirements		(574)
Other net	53	22
Net cash used by financing activities	(163)	(321)
INVESTING ACTIVITIES:		
Capital expenditures*	(1,833)	(2,111)
Purchases of business and investments/advances to affiliates	(214)	(459)
Other net	59	98
Net cash used by investing activities	(1,988)	(2,472)
Increase (decrease) in cash and cash equivalents	201	(852)
Cash and cash equivalents at beginning of period	795	1,867
Cash and cash equivalents at end of period	$ 996	$ 1,015

* Increases to property, plant, and equipment	$	(1,914)	$	(2,072)
Changes in related accounts payable and accrued liabilities		81		(39)
Capital expenditures	$	(1,833)	$	(2,111)

See accompanying notes.

Table of Contents

The Williams Companies, Inc.

Notes to Consolidated Financial Statements

(Unaudited)

Note 1. 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 Exhibit 99.1 of our Form 8-K dated June 1, 2011. The accompanying unaudited financial statements include all normal recurring adjustments and others that, in the opinion of management, are necessary to present fairly our financial position at September 30, 2011, results of operations and changes in equity for the three and nine months ended September 30, 2011 and 2010, and cash flows for the nine months ended September 30, 2011 and 2010.

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.

WPX Separation

On February 16, 2011, we announced that our Board of Directors approved our reorganization plan to divide our business into two separate, publicly traded corporations. This reorganization plan calls for a separation of our exploration and production business through an initial public offering (IPO) of our wholly owned subsidiary, WPX Energy, Inc. (WPX), and a subsequent tax-free spin-off of our remaining interest to our shareholders. WPX was formed in April 2011 to effect the separation. On April 29, 2011, WPX filed an S-1 registration statement with the Securities and Exchange Commission (SEC) with respect to an IPO of its equity securities and on October 28, 2011, filed the fifth amendment to this registration statement with the SEC.

On October 18, 2011, we announced that our Board of Directors approved a revised reorganization plan that calls for the complete separation of WPX via a tax-free spin-off of all of our ownership of WPX to our shareholders by year-end 2011. On October 19, 2011, WPX filed a Form 10 registration statement with the SEC with respect to this spin-off of its securities. The approval of the revised reorganization plan does not preclude us from pursuing the original plan including the IPO, in the event that market conditions become favorable. We retain the discretion to determine whether and when to complete these transactions.

Note 2. Basis of Presentation

Our operations are located principally in the United States and are organized into the following reporting segments: Williams Partners, Exploration & Production, and Midstream Canada & Olefins. All remaining business activities are included in Other.

Williams Partners consists of our consolidated master limited partnership, Williams Partners L.P. (WPZ) and includes our gas pipeline and domestic midstream businesses. The gas pipeline businesses include 100 percent of Transcontinental Gas Pipe Line Company, LLC (Transco), 100 percent of Northwest Pipeline GP (Northwest Pipeline), and 49 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream). WPZ s midstream operations are composed of significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, operations in Pennsylvania s Marcellus Shale region, and various equity investments in domestic natural gas gathering and processing assets and natural gas liquid (NGL) fractionation and transportation assets. WPZ s midstream assets also include substantial operations and investments in the Four Corners region, as well as an NGL fractionator and storage facilities near Conway, Kansas.

Exploration & Production includes the natural gas development, production and gas management activities, with operations primarily in the Rocky Mountain and Mid-Continent regions of the United States, natural gas development activities in the northeastern portion of the United States, oil and natural gas interests in South America, and oil development activities in the northern United States. The gas management activities include procuring fuel and shrink gas for our midstream businesses and providing marketing to third parties, such as producers. Additionally, gas management activities include managing various natural gas related contracts such as transportation, storage, and related hedges.

Our Midstream Canada & Olefins segment includes our oil sands off-gas processing plant near Fort McMurray, Alberta, our NGL/olefin fractionation facility and butylene/butane splitter facility at Redwater, Alberta, our NGL light-feed olefins cracker in Geismar, Louisiana, along with associated ethane and propane pipelines, and our refinery grade splitter in Louisiana.

7

Table of Contents

Notes (Continued)

Other includes other business activities that are not operating segments and corporate operations.

In May 2011, we contributed a 24.5 percent interest in Gulfstream to WPZ in exchange for aggregate consideration of $297 million of cash, 632,584 limited partner units, and an increase in the capital account of its general partner to allow us to maintain our 2 percent general partner interest. Williams Partners now holds a 49 percent interest in Gulfstream. We also own an additional 1 percent interest in Gulfstream reported in Other. Prior period segment disclosures have not been adjusted for this transaction as the impact, which was less than 2.5 percent of Williams Partners segment profit for all periods affected, was not material. Equity earnings related to this interest in Gulfstream that have not been recast are $9 million for the three months ended September 30, 2010 and $12 million and $24 million for the nine months ended September 30, 2011 and 2010, respectively. Equity earnings related to this interest in Gulfstream for the years ended December 31, 2010, 2009, and 2008 are $32 million, $30 million, and $27 million, respectively.

In November 2010, we contributed a business represented by certain gathering and processing assets in Colorado s Piceance basin to WPZ. The operations of this business and the related assets and liabilities were previously reported through our Exploration & Production segment, however they are now reported in our Williams Partners segment. Prior period segment disclosures have been recast for this transaction.

Master Limited Partnership

At September 30, 2011, we own approximately 75 percent of the interests in WPZ, including the interests of the general partner, which is wholly owned by us, and incentive distribution rights.

WPZ is self funding and maintains separate lines of bank credit and cash management accounts. Cash distributions from WPZ to us, including any associated with our incentive distribution rights, occur through the normal partnership distributions from WPZ to all partners.

Discontinued Operations

The accompanying consolidated financial statements and notes reflect the results of operations and financial position of Exploration & Production s Arkoma basin operations as discontinued operations for all periods. (See Note 3.)

Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to our continuing operations.

Accounting Standards Issued But Not Yet Adopted

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-4, Fair Value Measurement (Topic 820) Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS (ASU 2011-4). ASU 2011-4 primarily eliminates the differences in fair value measurement principles between the FASB and International Accounting Standards Board. It clarifies existing guidance, changes certain fair value measurements and requires expanded disclosure primarily related to Level 3 measurements and transfers between Level 1 and Level 2 of the fair value hierarchy. ASU 2011-4 is effective on a prospective basis for interim and annual periods beginning after December 15, 2011. We are assessing the application of this Update to our Consolidated Financial Statements.

In June 2011, the FASB issued Accounting Standards Update No. 2011-5, Comprehensive Income (Topic 220) Presentation of Comprehensive Income (ASU 2011-5). ASU 2011-5 requires presentation of net income and other comprehensive income either in a single continuous statement or in two separate, but consecutive, statements. The Update requires separate presentation in both net income and other comprehensive income of reclassification adjustments for items that are reclassified from other comprehensive income to net income. The new guidance does not change the items reported in other comprehensive income, nor affect how earnings per share is calculated and presented. We currently report net income in the Consolidated Statement of Operations and report other comprehensive income in the Consolidated Statement of Changes in Equity. The standard is effective beginning the first quarter of 2012, with a retrospective application to prior periods. We plan to apply the new presentation beginning in 2012.

8

Table of Contents

Notes (Continued)

Note 3. Discontinued Operations

Summarized Results of Discontinued Operations

	Three months ended September 30, 2011	2010	Nine months ended September 30, 2011	2010
	(Millions)			
Revenues	$ 3	$ 4	$ 10	$ 13
Income (loss) from discontinued operations before impairments and income taxes	$	$ (6)	$ (2)	$ (4)
Impairments	(5)		(16)	
(Provision) benefit for income taxes		1	2	(2)
Income (loss) from discontinued operations	$ (5)	$ (5)	$ (16)	$ (6)

Impairments in 2011 reflect write-downs to estimates of fair value less costs to sell the assets of our Arkoma basin operations. These nonrecurring fair value measurements, which fall within Level 3 of the fair value hierarchy, are based on probability-weighted discounted cash flow analyses that include purchase offers we have received for the assets.

The assets of our discontinued operations comprise significantly less than 0.5 percent of our total consolidated assets as of September 30, 2011, and December 31, 2010, and are reported primarily within *other current assets and deferred charges* and *other assets and deferred charges*, respectively, on our Consolidated Balance Sheet. Liabilities of our discontinued operations are insignificant for these periods.

Note 4. Asset Sales, Impairments and Other Accruals

The following table presents significant gains or losses reflected in *impairments of goodwill and long-lived assets* and *other (income) expense net* within *segment costs and expenses*:

	Three months ended September 30, 2011	2010	Nine months ended September 30, 2011	2010
	(Millions)			
Williams Partners				
Capitalization of project feasibility costs previously expensed	$	$	$ (10)	$
Involuntary conversion gains		(7)		(18)
Gain on sale of certain assets		(12)		(12)
Exploration & Production				
Impairment of goodwill		1,003		1,003
Impairments of producing properties and acquired unproved reserves		678		678

The reversal of project feasibility costs from expense to capital in 2011 at Williams Partners is associated with a natural gas pipeline expansion project. This reversal was made upon determining that the related project was probable of development. These costs will be included in the capital costs of the project, which we believe are probable of recovery through the project rates.

Impairments of goodwill and certain Exploration & Production properties

As a result of significant declines in forward natural gas prices during the third quarter of 2010, we performed an interim impairment assessment of our capitalized costs related to goodwill and domestic properties at Exploration & Production. As a result of these assessments, Exploration &

Production recorded an impairment of goodwill and impairments of capitalized costs of certain natural gas producing properties and acquired unproved reserves. See Note 10 for a further discussion of the impairments.

Table of Contents

Notes (Continued)

Additional Items

We completed a strategic restructuring transaction in the first quarter of 2010 that involved significant debt issuances, retirements and amendments. During the nine months ended September 30, 2010, we incurred significant costs related to these transactions, as follows:

- $606 million of early debt retirement costs consisting primarily of cash premiums;
- $45 million of other transaction costs reflected in *general corporate expenses,* of which $7 million is attributable to noncontrolling interests;
- $4 million of accelerated amortization of debt costs related to the amendments of credit facilities, reflected in *other income (expense) net* below *operating income (loss)*.

We recognized an $11 million gain in the first quarter of 2011 on the 2010 sale of our interest in Accroven SRL, reflecting the receipt of the first of six quarterly payments, which was originally due from the buyer in October 2010. We also recognized gains of $13 million in the second quarter of 2010 and $30 million in the third quarter of 2010 related to cash received on this sale. These gains are reflected within *investing income-net* at Other. Payments are recognized as income upon receipt until such time future collections are reasonably assured.

Exploration & Production recorded $12 million and $15 million of exploratory dry hole costs during the three months ended September 30, 2011 and 2010, respectively. These costs are included within *costs and operating expenses.*

During the third quarter of 2011, Exploration & Production recorded a charge of $50 million related to the impairment of certain leasehold costs to *costs and operating expenses*. The recording of the previously mentioned dry hole costs caused us to assess our ability to recover these unproved leasehold costs.

Exploration & Production recorded a $14 million unfavorable adjustment to *costs and operating expenses* for the nine months ended September 30, 2011, related to the correction of an error associated with our estimate of accrued minimum annual charges for compression service contracts in the Powder River basin.

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

Note 5. Provision (Benefit) for Income Taxes

The *provision (benefit) for income taxes* includes:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	(Millions)		(Millions)	
Current:				
Federal	$ 48	$ 67	$ 95	$ 24
State	3	8	6	(1)
Foreign	13	15	11	28

	64	90	112	51
Deferred:				
Federal	(17)	(220)	61	(182)
State	4	(23)	12	(17)
Foreign	4	3	9	8
	(9)	(240)	82	(191)
Total provision (benefit)	$ 55	$ (150)	$ 194	$ (140)

10

Table of Contents

Notes (Continued)

The effective income tax rate for the total provision for the three months ended September 30, 2011, is less than the federal statutory rate primarily due to the reversal of previously provided deferred taxes on undistributed earnings of certain foreign operations that are now considered to be permanently reinvested, the impact of nontaxable noncontrolling interests and federal settlements.

In the fourth-quarter 2010, we provided $66 million of deferred taxes on the undistributed earnings of certain foreign operations that we no longer considered permanently reinvested due to alternatives being considered related to the plan approved by our Board of Directors to pursue the separation of our exploration and production business through an IPO and subsequent tax-free spin-off (See Note 1). During the third quarter of 2011, we received a favorable ruling from the Internal Revenue Service (IRS) related to our plan of reorganization and finalization of our strategy related to these foreign operations which enabled us to recognize a deferred tax benefit of $66 million as we now consider the undistributed earnings of these certain foreign operations to be permanently reinvested.

The effective income tax rate for the total provision for the nine months ended September 30, 2011, is less than the federal statutory rate primarily due to federal settlements and an international revised assessment, the impact of nontaxable noncontrolling interests, the reversal of previously provided deferred taxes on undistributed earnings of certain foreign operations that are now considered to be permanently reinvested and taxes on foreign operations.

The effective income tax rate on the total benefit for the three and nine months ended September 30, 2010, is less than the federal statutory rate primarily due to a nondeductible goodwill impairment, partially offset by the impact of nontaxable noncontrolling interests. See Note 4 for a discussion of the goodwill impairment.

During the first quarter of 2011, we finalized settlements for 1997 through 2008 on certain contested matters with the IRS and also received a revised assessment on an international matter. These settlements and revised assessment resulted in a 2011 year-to-date tax benefit of approximately $135 million. As a result of these settlements and revised assessment, we have decreased our unrecognized tax benefits by approximately $62 million. In July and August 2011, we made cash payments to the IRS of $82 million and $77 million, respectively, related to these settlements.

During the next twelve months, we cannot predict with certainty whether we will achieve ultimate resolution of any uncertain tax position associated with our domestic or international operations that could result in significant increases or decreases of our unrecognized tax benefits, other than in regards to one individual item. In respect of one international issue, in the fourth quarter of 2011 we received an official notice reversing an assessment related to an international matter that should result in a decrease of approximately $13 million in our unrecognized tax benefits as early as the quarter ending December 31, 2011.

Note 6. Earnings (Loss) Per Common Share from Continuing Operations

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	(Dollars in millions, except per-share amounts; shares in thousands)			
Income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders for basic and diluted earnings (loss) per common share (1)	$ 277	$ (1,258)	$ 836	$ (1,265)
Basic weighted-average shares	588,950	584,744	588,082	584,365
Effect of dilutive securities:				
Nonvested restricted stock units	3,767		3,925	
Stock options	3,029		3,342	
Convertible debentures	1,804		1,901	
Diluted weighted-average shares	597,550	584,744	597,250	584,365

Earnings (loss) per common share from continuing operations:								
Basic	$	.47	$	(2.15)	$	1.42	$	(2.16)
Diluted	$	.47	$	(2.15)	$	1.40	$	(2.16)

Table of Contents

Notes (Continued)

(1) The three- and nine-month periods ended September 30, 2011, include $.2 million and $.5 million, respectively, of interest expense, net of tax, associated with our convertible debentures. This amount has been added back to *income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders* to calculate diluted earnings per common share.

For the three and nine months ended September 30, 2010, 2.9 million and 3.0 million, respectively, weighted-average nonvested restricted stock units and 2.4 million and 2.9 million, respectively, weighted-average stock options have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive due to our loss from continuing operations attributable to The Williams Companies, Inc.

Additionally, for the three and nine months ended September 30, 2010, 2.2 million weighted-average shares related to the assumed conversion of our convertible debentures, as well as the related interest, net of tax, have been excluded from the computation of diluted earnings per common share. Inclusion of these shares would have an antidilutive effect on the diluted earnings per common share. We estimate that if *income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders* was $54 million and $163 million of income for the three and nine months ended September 30, 2010, respectively, then these shares would become dilutive.

The table below includes information related to stock options that were outstanding at September 30 of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the third quarter weighted-average market price of our common shares.

	September 30,	
	2011	2010
Options excluded (millions)	3.0	6.9
Weighted-average exercise price of options excluded	$ 31.41	$ 24.54
Exercise price ranges of options excluded	$ 28.30 - $37.88	$ 19.29 - $40.51
Third quarter weighted-average market price	$ 27.72	$ 19.14

Note 7. Employee Benefit Plans

Net periodic benefit expense is as follows:

	Pension Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	(Millions)			
Components of net periodic benefit expense:				
Service cost	$ 11	$ 8	$ 31	$ 26
Interest cost	16	16	48	48
Expected return on plan assets	(20)	(18)	(58)	(53)
Amortization of prior service cost (credit)	1	1	1	1
Amortization of net actuarial loss	9	9	28	26
Net actuarial loss from settlements	4		4	
Net periodic benefit expense (income)	$ 21	$ 16	$ 54	$ 48

Table of Contents

Notes (Continued)

	Other Postretirement Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	(Millions)			
Components of net periodic benefit expense:				
Service cost	$ 1	$ 1	$ 2	$ 2
Interest cost	4	3	11	11
Expected return on plan assets	(3)	(2)	(8)	(7)
Amortization of prior service cost (credit)	(3)	(4)	(8)	(11)
Amortization of net actuarial loss	1	1	3	2
Amortization of regulatory asset	1		1	1
Net periodic benefit expense (income)	$ 1	$ (1)	$ 1	$ (2)

During the nine months ended September 30, 2011, we contributed $67 million to our pension plans and $11 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $1 million to our pension plans and approximately $4 million to our other postretirement benefit plans in the remainder of 2011.

Note 8. Inventories

	September 30, 2011	December 31, 2010
	(Millions)	
Natural gas liquids and olefins	$ 112	$ 87
Natural gas in underground storage	61	93
Materials, supplies, and other	114	122
	$ 287	$ 302

Note 9. Debt and Banking Arrangements

Credit Facilities

In June 2011, we entered into three new separate five-year senior unsecured revolving credit facility agreements. The replacements of our previous $900 million credit facility and WPZ s $1.75 billion credit facility, as discussed further below, are considered modifications for accounting purposes.

We established a new $900 million unsecured revolving credit facility agreement which replaced our existing unsecured $900 million credit facility agreement that was scheduled to expire May 1, 2012. There were no outstanding borrowings under the existing agreement at the time it was terminated. The new credit facility may, under certain conditions, be increased up to an additional $250 million. Significant financial covenants require our ratio of debt to EBITDA (each as defined in the credit facility) to be no greater than 4.5 to 1. For the fiscal quarter and the two following fiscal quarters in which one or more acquisitions for a total aggregate purchase price equal to or greater than $50 million has been executed, we are required to maintain a ratio of debt to EBITDA of no greater than 5 to 1. At September 30, 2011, we are in compliance with these financial covenants. On November 1, 2011, the new credit facility was amended primarily to revise certain defined terms for further clarity and to accommodate our revised reorganization plan.

WPZ also established a new $2 billion unsecured revolving credit facility agreement that includes Transco and Northwest Pipeline as co-borrowers that replaced an existing unsecured $1.75 billion credit facility agreement that was scheduled to expire on February 17, 2013. This credit facility is only available to named borrowers. At the closing, WPZ refinanced $300 million outstanding under the existing facility via a non-cash transfer of the obligation to the new credit facility. The new credit facility may, under certain conditions, be increased up to an additional $400 million. The full amount of the credit facility is available to WPZ to the extent not otherwise utilized by Transco and Northwest Pipeline. Transco and Northwest Pipeline each have access to borrow up to $400 million under the credit facility to the extent not otherwise utilized by the other co-borrowers. Significant financial covenants include:

Table of Contents

Notes (Continued)

WPZ s ratio of debt to EBITDA (each as defined in the credit facility) must be no greater than 5 to 1. For the fiscal quarter and the two following fiscal quarters in which one or more acquisitions for a total aggregate purchase price equal to or greater than $50 million has been executed, WPZ is required to maintain a ratio of debt to EBITDA of no greater than 5.5 to 1;

The ratio of debt to capitalization (defined as net worth plus debt) must be no greater than 65 percent for each of Transco and Northwest Pipeline.

At September 30, 2011, WPZ is in compliance with these financial covenants.

WPX entered into a new $1.5 billion unsecured revolving credit facility agreement that would be effective upon meeting certain conditions. This agreement was amended on November 1, 2011 and became effective the same day. The amendment provides for WPX granting a priority lien on at least 80 percent of the present value of its proved reserves (as defined in the agreement) if, upon the first issuance of WPX senior unsecured notes, WPX s long-term senior unsecured debt rating is equal to or less than Ba2 and BB by Moody s and S&P, respectively. This provision is only applicable upon the first issuance of WPX senior unsecured notes and any liens granted pursuant to these terms would automatically terminate upon WPX achieving investment grade credit ratings, as described in the agreement, or upon termination of the agreement. Also, on November 1, 2011, Exploration & Production terminated its existing unsecured credit agreement which had served to reduce margin requirements and transaction fees related to hedging activities, thus satisfying a condition necessary for effectiveness of the new WPX credit facility. All outstanding hedges under the terminated agreement were transferred to new agreements with various financial institutions that participate in the new credit facility. Neither WPX nor the participating financial institutions are required to provide collateral support related to hedging activities under the new agreements. The new credit facility is only available to WPX and may, under certain conditions, be increased up to an additional $300 million. WPX may also request a swingline loan to obtain same-day funds of up to $125 million under the agreement.

Significant financial covenants include:

WPX s PV to debt (each as defined in the credit facility and PV primarily relating to the present value of proved oil and gas reserves) of at least 1.5 to 1;

The ratio of WPX s debt to capitalization (defined as net worth plus debt) must be no greater than 60 percent.

These covenants will be measured beginning December 31, 2011.

The three new credit agreements contain the following terms and conditions:

Each time funds are borrowed, with the exception of swingline loans under the WPX agreement, the applicable borrower may choose from two methods of calculating interest: a fluctuating base rate equal to Citibank N.A. s adjusted base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. Interest on swingline loans is payable at a rate per annum equal to a fluctuating base rate equal to Citibank N.A. s adjusted base rate plus an applicable margin. The applicable borrower is required to pay a commitment fee (currently 0.25 percent for our agreement, 0.25 percent for the WPZ agreement and 0.325 percent for the WPX agreement) based on the unused portion of their respective credit facility. The applicable margin and the commitment fee are determined for each borrower by reference to a pricing schedule based on such borrower s senior unsecured long-term debt ratings.

Various covenants may limit, among other things, a borrower s and its material subsidiaries ability to grant certain liens supporting indebtedness, a borrower s ability to merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default, make investments, and allow any material change in the nature of its business. WPX s credit agreement further limits WPX and its material subsidiaries ability to make certain investments, loans, or advances or enter into certain hedging agreements beyond the ordinary course of business.

If an event of default with respect to a borrower occurs under their respective credit facility agreement, the lenders will be able to terminate the commitments for the respective borrowers and accelerate the maturity of any loans of the defaulting borrower under the respective credit facility agreement and exercise other rights and remedies.

Letters of credit issued and loans outstanding under the credit facility agreements in effect at September 30, 2011, are:

Table of Contents

Notes (Continued)

	Expiration	Letters of Credit	Loans
		(Millions)	
$900 million unsecured credit facility (1)	June 3, 2016	$	$
$2 billion WPZ unsecured credit facility (2)	June 3, 2016		400
Bilateral bank agreements for letters of credit		89	
		$ 89	$ 400

(1) $700 million letter of credit capacity.
(2) $1.3 billion letter of credit capacity.

Issuances and Retirements

Utilizing cash on hand, WPZ retired $150 million of 7.5 percent senior unsecured notes that matured on June 15, 2011.

In August 2011, Transco issued $375 million of 5.4 percent senior unsecured notes due 2041 to investors in a private debt placement. A portion of these proceeds were used to repay Transco s $300 million 7 percent senior unsecured notes that matured on August 15, 2011. 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 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.

Note 10. Fair Value Measurements

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis.

	September 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(Millions)				
Assets:								
Energy derivatives	$ 52	$ 444	$ 3	$ 499	$ 96	$ 475	$ 2	$ 573
ARO Trust investments (see Note 11)	27			27	40			40
Available-for-sale equity securities (see Note 11)	23			23				
Total assets	$ 102	$ 444	$ 3	$ 549	$ 136	$ 475	$ 2	$ 613
Liabilities:								
Energy derivatives	$ 45	$ 129	$ 2	$ 176	$ 78	$ 210	$ 1	$ 289
Total liabilities	$ 45	$ 129	$ 2	$ 176	$ 78	$ 210	$ 1	$ 289

Table of Contents

Notes (Continued)

Energy derivatives include commodity based exchange-traded contracts and over-the-counter (OTC) contracts. Exchange-traded contracts include futures, swaps, and options. OTC contracts include forwards, swaps and options.

The instruments included in our Level 1 measurements consist of energy derivatives that are exchange-traded, a portfolio of mutual funds, and an investment in marketable equity securities. Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets.

The instruments included in our Level 2 measurements consist primarily of OTC instruments. Forward, swap, and option contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Significant inputs into our Level 2 valuations include commodity prices, implied volatility by location, 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.

The instruments in our Level 3 measurements primarily consist of natural gas index transactions that are used by our Exploration & Production segment to manage physical requirements. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 because these inputs have a significant impact on the measurement of fair value. As the fair value of natural gas index transactions is primarily driven by the typically nominal differential transacted and the market price, these transactions do not have a material impact on our results of operations or liquidity.

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 99 percent of the value of our derivatives portfolio expiring in the next 15 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

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 significant transfers between Level 1 and Level 2 occurred during the period ended September 30, 2011 or 2010.

The following table presents a reconciliation of changes in the fair value of our net energy derivatives classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	(Millions)			
Beginning balance	$ 1	$ 14	$ 1	$ 2
Realized and unrealized gains (losses):				
Included in income (loss) from continuing operations	4	7	6	6
Included in other comprehensive income (loss)		(14)	(1)	1
Settlements	(4)	(6)	(6)	(8)
Transfers into Level 3				
Transfers out of Level 3			1	
Ending balance	$ 1	$ 1	$ 1	$ 1
	$ 1	$ 1	$ 1	$ 1

Unrealized gains (losses) included in *income (loss) from continuing operations* relating to instruments still held at September 30

16

Table of Contents

Notes (Continued)

Realized and unrealized gains (losses) included in *income (loss) from continuing operations* for the above periods are reported in *revenues* or *costs and operating expenses* in our Consolidated Statement of Operations.

There were no assets or liabilities measured at fair value on a nonrecurring basis as of September 30, 2011. The following table presents assets measured on a nonrecurring basis within Level 3 of the fair value hierarchy as of September 30, 2010. There were no liabilities measured on a nonrecurring basis as of September 30, 2010.

	Fair Value Measurement	Total Impairments
	(Millions)	
Domestic goodwill Exploration & Production	$	$ 1,003
Certain producing properties and acquired unproved reserves Exploration & Production	320	678
	$ 320	$ 1,681

Domestic goodwill at Exploration & Production

Due to a significant decline in forward natural gas prices across all future production periods as of September 30, 2010, we performed an interim impairment assessment of goodwill at Exploration & Production related to its domestic natural gas production operations (the reporting unit). Forward natural gas prices through 2025 as of September 30, 2010, used in our analysis declined more than 22 percent on average compared to the forward prices as of December 31, 2009. We estimated the fair value of the reporting unit on a stand-alone basis by valuing proved and unproved reserves, as well as estimating the fair values of other assets and liabilities which are identified to the reporting unit. We used an income approach (discounted cash flow) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves included reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions in valuing proved reserves included reserves quantities of more than 4.4 trillion cubic feet of gas equivalent; forward prices averaging approximately $4.65 per thousand cubic feet of gas equivalent (Mcfe) for natural gas (adjusted for locational differences), NGLs and oil; and an after-tax discount rate of 11 percent. Unproved reserves (probable and possible) were valued using similar assumptions adjusted further for the uncertainty associated with these reserves by using after-tax discount rates of 13 percent and 15 percent, respectively, commensurate with our estimate of the risk of those reserves. In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its estimated fair value. As a result of our analysis, we recognized an impairment charge equal to the full carrying amount of this goodwill.

Certain producing properties and acquired unproved reserves at Exploration & Production

As of September 30, 2010, we assessed the carrying value of Exploration & Production s natural gas-producing properties and costs of acquired unproved reserves, for impairments as a result of recent significant declines in forward natural gas prices. Our assessment utilized estimates of future cash flows. Significant judgments and assumptions in these assessments are similar to those used in the goodwill evaluation and include estimates of natural gas reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. The assessment performed at September 30, 2010, identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded an impairment charge in third-quarter 2010 as further described below.

$503 million of the impairment charge related to natural gas-producing properties in the Barnett Shale. Significant assumptions in valuing these properties included proved reserves quantities of more than 227 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $4.67 per Mcfe for natural gas (adjusted for locational differences), NGLs and oil, and an after-tax discount rate of 11 percent.

Notes (Continued)

$175 million of the impairment charge related to acquired unproved reserves in the Piceance Highlands acquired in 2008. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, drilling plans, forward natural gas (adjusted for locational differences) and NGLs prices, and an after-tax discount rate of 13 percent.

Note 11. Financial Instruments, Derivatives, Guarantees, and Concentration of Credit Risk

Financial Instruments

Fair-value methods

We use the following methods and assumptions in estimating our fair-value disclosures for financial instruments:

Cash and cash equivalents and restricted cash: The carrying amounts reported in the Consolidated Balance Sheet approximate fair value due to the short-term maturity of these instruments. Current and noncurrent restricted cash is included in *other current assets and deferred charges* and *other assets and deferred charges*, respectively, in the Consolidated Balance Sheet, based on the term of the related restriction.

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

Long-term debt: The fair value of our publicly traded long-term debt is determined using indicative period-end traded bond market prices. The fair value of our private debt is based on market rates and the prices of similar securities with similar terms and credit ratings. At September 30, 2011 and December 31, 2010, approximately 92 percent and 100 percent, respectively, of our long-term debt was publicly traded. (See Note 9.)

Guarantee: The *guarantee* represented in the following table consists of a guarantee we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on a lease performance obligation. To estimate the fair value of the guarantee, the estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate based on the credit rating of WilTel s current owner and the term of the underlying obligation. The default rate is published by Moody s Investors Service. This guarantee is included in *accrued liabilities* in the Consolidated Balance Sheet.

Other: Includes current and noncurrent notes receivable, margin deposits, customer margin deposits payable, and cost-based investments. Other also includes available-for-sale equity securities. These instruments are reported within *investments* in the Consolidated Balance Sheet and are carried at fair value based upon the publicly traded equity prices.

Energy derivatives: Energy derivatives include futures, forwards, swaps, and options. These are carried at fair value in the Consolidated Balance Sheet. See Note 10 for a discussion of the valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments

	September 30, 2011		December 31, 2010	
Asset (Liability)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions)			
Cash and cash equivalents	$ 996	$ 996	$ 795	$ 795
Restricted cash (current and noncurrent)	$ 29	$ 29	$ 28	$ 28
ARO Trust investments	$ 27	$ 27	$ 40	$ 40
Long-term debt, including current portion (a)	$ (9,380)	$ (10,580)	$ (9,104)	$ (9,990)
Guarantee	$ (34)	$ (32)	$ (35)	$ (34)
Other	$ 34	$ 33(b)	$ (23)	$ (25)(b)

Net energy derivatives:								
Energy commodity cash flow hedges	$	313	$	313	$	266	$	266
Other energy derivatives	$	10	$	10	$	18	$	18

Notes (Continued)

(a) Excludes capital leases.
(b) Excludes certain cost-based investments in companies that are not publicly traded and therefore it is not practicable to estimate fair value. The carrying value of these investments was $1 million and $2 million at September 30, 2011 and December 31, 2010, respectively.

Energy Commodity Derivatives

Risk management activities

We are exposed to market risk from changes in energy commodity prices within our operations. We manage this risk on an enterprise basis and may utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases and sales of natural gas, crude oil and 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 produce, buy, and sell natural gas and crude oil at different locations throughout the United States. We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in revenues or margins from fluctuations in natural gas and crude oil market prices, we enter into natural gas and crude oil futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas and crude oil. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. 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. Our financial option contracts are either purchased options or a combination of options that comprise a net purchased option or a zero-cost collar. Our designation of the hedging relationship and method of assessing effectiveness for these option contracts are generally such that the hedging relationship is considered perfectly effective and no ineffectiveness is recognized in earnings. Hedges for storage contracts have not been designated as cash flow hedges, despite economically hedging the expected cash flows generated by those agreements.

We produce and sell NGLs and olefins at different locations throughout North America. We also buy natural gas to satisfy the required fuel and shrink needed to generate NGLs and olefins. In addition, we buy NGLs as feedstock to generate olefins. 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 and NGL market prices, we may enter into NGL or natural gas swap agreements, financial forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs and purchases of natural gas and NGLs. 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.

Other activities

We also enter into energy commodity derivatives for other than risk management purposes, including managing certain remaining legacy natural gas contracts and positions from our former power business and providing services to third parties. These legacy natural gas contracts include substantially offsetting positions and have an insignificant net impact on earnings.

Volumes

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

Table of Contents

Notes (Continued)

Central hub risk: Includes physical and financial derivative exposures to Henry Hub for natural gas, West Texas Intermediate for crude oil, and Mont Belvieu for NGLs;

Basis risk: Includes physical and financial derivative exposures to the difference in value between the central hub and another specific delivery point;

Index risk: Includes physical derivative exposure at an unknown future price;

Options: Includes all fixed price options or combination of options (collars) that set a floor and/or ceiling for the transaction price of a commodity.

Fixed price swaps at locations other than the central hub are classified as both central hub risk and basis risk instruments to represent their exposure to overall market conditions (central hub risk) and specific location risk (basis risk).

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of September 30, 2011. NGLs and crude oil are presented in barrels and natural gas is presented in millions of British Thermal Units (MMBtu). The volumes for options represent at location zero-cost collars and present one side of the short position. The net index position for Exploration & Production includes certain positions on behalf of other segments.

Derivative Notional Volumes		Unit of Measure	Central Hub Risk	Basis Risk	Index Risk	Options
Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(224,180,000)	(224,180,000)		(25,300,000)
Exploration & Production	Risk Management	Barrels	(3,038,000)			
Williams Partners	Risk Management	MMBtu	5,060,000	4,370,000		
Williams Partners	Risk Management	Barrels	(1,380,000)			
Not Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(11,400,829)	(6,733,329)	(81,599,245)	
Williams Partners	Risk Management	Barrels	105,000			
Midstream Canada & Olefins	Risk Management	Barrels	(150,000)		(72,150)	
Exploration & Production	Other	MMBtu		(6,110,000)		

Fair values and gains (losses)

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Consolidated Balance Sheet as current and noncurrent derivative assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 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 below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	September 30, 2011		December 31, 2010	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Designated as hedging instruments	$ 335	$ 22	$ 288	$ 22
Not designated as hedging instruments:				

Legacy natural gas contracts from former power business	129	128	186	187
All other	35	26	99	80
Total derivatives not designated as hedging instruments	164	154	285	267
Total derivatives	$ 499	$ 176	$ 573	$ 289

Table of Contents

Notes (Continued)

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in AOCI, *revenues,* or *costs and operating expenses*.

	Three months ended September 30, 2011	2010	Nine months ended September 30, 2011	2010	Classification
	(Millions)		(Millions)		
Net gain (loss) recognized in other comprehensive income (loss) (effective portion)	$ 204	$ 214	$ 256	$ 524	AOCI
Net gain (loss) reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$ 70	$ 110	$ 208	$ 235	Revenues or Costs and Operating Expenses
Gain (loss) recognized in income (ineffective portion)	$	$ 1	$	$ 4	Revenues or Costs and Operating Expenses

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness or as a result of reclassifications to earnings following the discontinuance of any cash flow hedges.

The following table presents pre-tax gains and losses for our energy commodity derivatives not designated as hedging instruments.

	Three months ended September 30, 2011	2010	Nine months ended September 30, 2011	2010
	(Millions)		(Millions)	
Revenues	$ 13	$ 26	$ 17	$ 37
Costs and operating expenses		11		18
Net gain (loss)	$ 13	$ 15	$ 17	$ 19

The cash flow impact of our derivative activities is presented in the Consolidated Statement of Cash Flows as *changes in current and noncurrent derivative 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. Exploration & Production had an unsecured credit agreement with certain banks related to hedging activities. We were not required to provide collateral support for net derivative liability positions under the credit agreement as long as the value of Exploration & Production s domestic natural gas reserves, as determined under the provisions of the agreement, exceeded by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money position on hedges entered into under the credit agreement. On November 1, 2011, Exploration & Production terminated this credit agreement. (See Note 9.)

As of September 30, 2011, we have collateral totaling $4 million, all of which is in the form of letters of credit, posted to derivative counterparties to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $22 million, which includes a

21

reduction of less than $1 million to our liability balance for our own nonperformance risk. At December 31, 2010, we had collateral totaling $8 million posted to derivative counterparties, all of which was in the form of letters of credit, to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $36 million, which included a reduction of less than $1 million to our liability balance for our own nonperformance risk. The additional collateral that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, was $18 million and $29 million at September 30, 2011 and December 31, 2010, respectively.

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, 2011, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to two years. Based on recorded values at September 30, 2011, $167 million of net gains (net of income tax provision of $101 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of September 30, 2011. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized within the next year 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.

Guarantees

We are required by our revolving credit agreements to indemnify lenders for any taxes required to be withheld from payments due to the lenders and for any 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.

We have provided a guarantee in the event of nonpayment by our previously owned communications subsidiary, WilTel, on a certain lease performance obligation that extends through 2042. The maximum potential exposure is approximately $38 million at September 30, 2011 and $39 million at December 31, 2010. Our exposure declines systematically throughout the remaining term of WilTel s obligation. The carrying value of the guarantee included in *accrued liabilities* on the Consolidated Balance Sheet is $34 million at September 30, 2011 and $35 million at December 31, 2010.

At September 30, 2011, we do not expect these guarantees to have a material impact on our future liquidity or financial position. However, if we are required to perform on these guarantees in the future, it may have an adverse effect on our results of operations.

Concentration of Credit Risk

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements, and guarantees of payment by credit worthy parties. The gross credit exposure from our derivative contracts as of September 30, 2011, is summarized as follows:

Table of Contents

Notes (Continued)

Counterparty Type	Investment Grade(a)	Total
	000000	000000
	(Millions)	
Gas and electric utilities	$ 3	$ 3
Energy marketers and traders		74
Financial institutions	422	422
	$ 425	499
Credit reserves		
Gross credit exposure from derivatives		$ 499

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of September 30, 2011, excluding collateral support discussed below, is summarized as follows:

Counterparty Type	Investment Grade(a)	Total
	000000	000000
	(Millions)	
Gas and electric utilities	$ 2	$ 2
Energy marketers and traders		1
Financial institutions	342	342
	$ 344	345
Credit reserves		
Net credit exposure from derivatives		$ 345

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor s rating of BBB- or Moody s Investors Service rating of Baa3 in investment grade.

As of September 30, 2011, our eight largest net counterparty positions represent approximately 98 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are counterparty positions, representing 91 percent of our net credit exposure from derivatives, associated with Exploration & Production s hedging facility. Under certain conditions, the terms of this credit agreement may require the participating financial institutions to deliver collateral support to a designated collateral agent (which is another participating financial institution in the agreement). The level of collateral support required is dependent on whether the net position of the counterparty financial institution exceeds specified thresholds. The thresholds may be subject to prescribed reductions based on changes in the credit rating of the counterparty financial institution. This credit agreement was terminated on November 1, 2011. (See Note 9.)

At September 30, 2011, the designated collateral agent is not required to hold any collateral support on our behalf under Exploration & Production s hedging facility. We hold collateral support, which may include cash or letters of credit, of $5 million related to our other derivative positions.

Note 12. Contingent Liabilities

Issues Resulting from California Energy Crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the Federal Energy Regulatory Commission (FERC). We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. We are currently in settlement negotiations with certain

Table of Contents

Notes (Continued)

California utilities aimed at eliminating or substantially reducing this exposure. If successful, and subject to a final true-up mechanism, the settlement agreement would also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement would resolve most, if not all, of our legal issues arising from the 2000-2001 California Energy Crisis. With respect to these matters, amounts accrued are not material to our financial position.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Reporting of Natural Gas-Related Information to Trade Publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin brought on behalf of direct and indirect purchasers of natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs lack of standing. In 2009, the court denied the plaintiffs request for reconsideration of the Colorado dismissal and entered judgment in our favor. The court s order became final on July 18, 2011, and we expect that the Colorado plaintiffs will appeal.

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs class certification motion as moot. On July 22, 2011, the plaintiffs filed their notice of appeal with the Nevada district court. Because of the uncertainty around these current pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time. However, it is reasonably possible that the ultimate resolution of these items could result in future charges that may be material to our results of operations.

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 disposal 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, 2011, we have accrued liabilities totaling $47 million for these matters, as discussed below. Our estimated costs reflect 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. Actual costs for these matters could be substantially greater than amounts accrued depending on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities. As a result, any incremental amount cannot be reasonably estimated at this time.

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new 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.

Notes (Continued)

Continuing operations

Our interstate gas pipelines are involved in remediation activities related to certain facilities and locations for polychlorinated biphenyl, mercury contamination, and other hazardous substances. These activities have involved the EPA, various state environmental authorities and identification as a potentially responsible party at various Superfund waste disposal sites. At September 30, 2011, we have accrued liabilities of $11 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, 2011, we have accrued liabilities totaling $8 million for these costs.

Former operations, including operations classified as discontinued

We have potential obligations in connection with assets and businesses we no longer operate. These potential obligations include the indemnification of the purchasers of certain of these assets and businesses for environmental and other liabilities existing at the time the sale was consummated. Our responsibilities relate to the operations of the assets and businesses described below.

- Former agricultural fertilizer and chemical operations and former retail petroleum and refining operations;
- Former petroleum products and natural gas pipelines;
- Former petroleum refining facilities;
- Former exploration and production and mining operations.

At September 30, 2011, we have accrued environmental liabilities of $28 million related to these matters.

Other Legal Matters

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay (a joint venture between Gulsby and Bay Ltd.) for the construction of certain gas processing plants in Louisiana. National American Insurance Company (NAICO) and American Home Assurance Company provided payment and performance bonds for the projects. In 2001, the contractors and sureties filed multiple cases in Louisiana and Texas against Gulf Liquids and us.

In 2006, at the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual and punitive damages verdict against us and Gulf Liquids. Based on our interpretation of the jury verdicts, we recorded a charge based on our estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $20 million. In addition, we concluded that it was reasonably possible that any ultimate judgment might have included additional amounts of approximately $199 million in excess of our accrual, which primarily represented our estimate of potential punitive damage exposure under Texas law.

From May through October 2007, the court entered seven post-trial orders in the case (interlocutory orders) which, among other things, overruled the verdict award of tort and punitive damages as well as any damages against us. The court also denied the plaintiffs claims for attorneys fees. On January 28, 2008, the court issued its judgment awarding damages against Gulf Liquids of approximately $11 million in favor of Gulsby and approximately $4 million in favor of Gulsby-Bay. Gulf Liquids, Gulsby, Gulsby-Bay, Bay Ltd., and NAICO appealed the judgment. In February 2009, we settled with certain of these parties and reduced our liability as of December 31, 2008, by $43 million, including

$11 million of interest. On February 17, 2011, the Texas Court of Appeals upheld the dismissals of the tort and punitive damages claims and reversed and remanded the contract claim and attorney fee claims for further proceedings. The appellate court ruling is subject to a potential appeal to the Texas Supreme Court. If the appellate court judgment is upheld, our remaining liability could be less than the amount of our accrual for these matters.

Notes (Continued)

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in District Court, Garfield County Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of natural gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify as a class of royalty interest owners, recover underpayment of royalties and obtain corrected payments resulting from calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement defined the class members for class certification, reserved two claims for court resolution, resolved all other class claims relating to past calculation of royalty and overriding royalty payments, and established certain rules to govern future royalty and overriding royalty payments. This settlement resolved all claims relating to past withholding for ad valorem tax payments and established a procedure for refunds of any such excess withholding in the future. The first reserved claim is whether we are entitled to deduct in our calculation of royalty payments a portion of the costs we incur beyond the tailgates of the treating or processing plants for mainline pipeline transportation. We received a favorable ruling on our motion for summary judgment on the first reserved claim. Plaintiffs appealed that ruling and the Colorado Court of Appeals found in our favor in April 2011. In June 2011, Plaintiffs filed a Petition for Certiorari with the Colorado Supreme Court. We anticipate that court will issue a decision on whether to grant further review later in 2011 or early in 2012. The second reserved claim relates to whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are thus entitled to deduct a proportionate share of transportation costs in calculating royalty payments. We anticipate trial on the second reserved claim following resolution of the first reserved claim. We believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law. At this time, the plaintiffs have not provided us a sufficient framework to calculate an estimated range of exposure related to their claims. However, it is reasonably possible that the ultimate resolution of this item could result in a future charge that may be material to our results of operations.

Other producers have been in litigation or discussions with a federal regulatory agency and a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to these matters, we have monitored them to evaluate whether their resolution might have the potential for an unfavorable impact on our results of operations. One of these matters involving federal litigation was decided on October 5, 2009. The resolution of this specific matter is not material to us. However, other related issues in these matters that could be material to us remain outstanding. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue (ONRR) in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The ONRR s guidance provides its view as to how much of a producer s bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states, but such guidelines are expected in the future. However, the timing of receipt of the necessary guidelines is uncertain. In addition, these interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and will vary based upon the ONRR s assessment of the configuration of processing, treating and transportation operations supporting each federal lease. From January 2004 through December 2010, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $55 million. Correspondence in 2009 with the ONRR s predecessor did not take issue with our calculation regarding the Piceance basin assumptions which we believe have been consistent with the requirements. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments and the effect could be material to our results of operations.

Other

In 2003, we entered into an agreement to sublease certain underground storage facilities to Liberty Gas Storage (Liberty). We have asserted claims against Liberty for prematurely terminating the sublease and for damage caused to the facilities. In February 2011, Liberty asserted a counterclaim for costs in excess of $200 million associated with its use of the facilities. Due to the lack of information currently available, we are unable to evaluate the merits of the counterclaim and determine the amount of any possible liability.

Notes (Continued)

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, property damage, environmental matters, right of way and other representations that we have provided.

At September 30, 2011, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

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

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 have disclosed all significant matters for which we are unable to reasonably estimate a range of possible loss.

Litigation, arbitration, regulatory matters, environmental matters and safety matters are subject to inherent uncertainties and there always exists uncertainty about our future results of operations. As a result, if an unforeseen, unfavorable event occurred, there exists the possibility of a material adverse impact on the results of operations in the period in which the event occurs. Management, including internal counsel, currently believes that the ultimate resolution of these matters, taken as a whole, will not have a material adverse effect upon our future liquidity or financial position. In certain circumstances, we may be eligible for insurance recoveries, or reimbursements from others. Any such recoveries or reimbursements will be recognized only when realizable.

Note 13. Segment Disclosures

Our reporting segments are Williams Partners, Exploration & Production and Midstream Canada & Olefins. All remaining business activities are included in Other. (See Note 2.)

Performance Measurement

We currently evaluate performance based upon *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses*, *equity earnings (losses)* and *income (loss) from investments*. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

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

Williams Partners commodity purchases (primarily for NGL and crude marketing, shrink and fuel), depreciation and operation and maintenance expenses;

Exploration & Production commodity purchases (primarily in support of commodity marketing and risk management activities), depletion, depreciation and amortization, lease and facility operating expenses and operating taxes;

Midstream Canada & Olefins commodity purchases (primarily for shrink, feedstock and NGL and olefin marketing activities), depreciation and operation and maintenance expenses.

Table of Contents

Notes (Continued)

The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income (loss)* as reported in the Consolidated Statement of Operations and *total assets* by reporting segment.

	Williams Partners	Exploration & Production	Midstream Canada & Olefins (Millions)	Other	Eliminations	Total
Three months ended September 30, 2011						
Segment revenues:						
External	$ 1,560	$ 817	$ 325	$ 1	$	$ 2,703
Internal	113	205	1	5	(324)	
Total revenues	$ 1,673	$ 1,022	$ 326	$ 6	$ (324)	$ 2,703
Segment profit (loss)	$ 471	$ 48	$ 73	$ 1	$	$ 593
Less equity earnings (losses)	40	5				45
Segment operating income (loss)	$ 431	$ 43	$ 73	$ 1	$	548
General corporate expenses						(54)
Total operating income (loss)						$ 494
Three months ended September 30, 2010						
Segment revenues:						
External	$ 1,236	$ 833	$ 228	$ 3	$	$ 2,300
Internal	91	172	4	3	(270)	
Total revenues	$ 1,327	$ 1,005	$ 232	$ 6	$ (270)	$ 2,300
Segment profit (loss)	$ 371	$ (1,630)	$ 42	$ 38	$	$ (1,179)
Less:						
Equity earnings (losses)	24	5		9		38
Income (loss) from investments				30		30
Segment operating income (loss)	$ 347	$ (1,635)	$ 42	$ (1)	$	(1,247)
General corporate expenses						(43)
Total operating income (loss)						$ (1,290)
Nine months ended September 30, 2011						
Segment revenues:						
External	$ 4,595	$ 2,358	$ 986	$ 8	$	$ 7,947
Internal	328	634	3	11	(976)	
Total revenues	$ 4,923	$ 2,992	$ 989	$ 19	$ (976)	$ 7,947
Segment profit (loss)	$ 1,379	$ 193	$ 219	$ 23	$	$ 1,814

Less:						
Equity earnings (losses)	101	16		13		130
Income (loss) from investments				11		11
Segment operating income (loss)	$ 1,278	$ 177	$ 219	$ (1)	$	1,673
General corporate expenses						(152)
Total operating income (loss)						$ 1,521
Nine months ended September 30, 2010						
Segment revenues:						
External	$ 3,940	$ 2,484	$ 749	$ 7	$	$ 7,180
Internal	277	579	12	10	(878)	
Total revenues	$ 4,217	$ 3,063	$ 761	$ 17	$ (878)	$ 7,180
Segment profit (loss)	$ 1,156	$ (1,404)	$ 123	$ 63	$	$ (62)
Less:						
Equity earnings (losses)	77	15		25		117
Income (loss) from investments				43		43
Segment operating income (loss)	$ 1,079	$ (1,419)	$ 123	$ (5)	$	(222)
General corporate expenses						(173)
Total operating income (loss)						$ (395)
September 30, 2011						
Total assets (a)	$ 14,047	$ 10,038	$ 1,071	$ 1,322	$ (332)	$ 26,146
December 31, 2010						
Total assets	$ 13,404	$ 9,827	$ 922	$ 3,481	$ (2,662)	$ 24,972

(a) The decrease in Other and Eliminations as compared to the prior year-end is substantially due to the forgiveness of an intercompany long-term receivable in the second-quarter of 2011.

Table of Contents

Notes (Continued)

Total segment revenues for Exploration & Production include gas management revenues of $347 million and $436 million for the three months ended September 30, 2011 and 2010, respectively, and $1,089 million and $1,357 million for the nine months ended September 30, 2011 and 2010, respectively. Gas management revenues include sales of natural gas in conjunction with marketing services provided to third parties and intercompany sales of fuel and shrink gas to the midstream businesses in Williams Partners. These revenues are substantially offset by similar amounts of gas management costs.

Table of Contents

Item 2

Management s Discussion and Analysis of

Financial Condition and Results of Operations

Changes in Structure and Dividend Increases

On February 16, 2011, we announced our reorganization plan to divide our business into two separate, publicly traded corporations. This reorganization plan calls for a separation of our exploration and production business through an initial public offering (IPO) of up to 20 percent of our wholly owned subsidiary, WPX Energy, Inc. (WPX) and a subsequent tax-free spin-off of our remaining interest in WPX to our shareholders. On April 29, 2011, WPX filed an S-1 registration statement with the SEC with respect to an IPO of its equity securities and on October 28, 2011, WPX filed the fifth amendment to this registration statement with the SEC. After our reorganization plan Williams will continue as a natural gas infrastructure company.

On October 18, 2011, we announced that our Board of Directors approved a revised reorganization plan that calls for the complete separation of WPX via a tax-free spin-off of all of our ownership of WPX to our shareholders by year-end 2011. On October 19, 2011, WPX filed a Form 10 registration statement with the SEC with respect to this spin-off of its securities. The approval of the revised reorganization plan does not preclude us from pursuing the original plan including the IPO in the event market conditions become favorable. We retain the discretion to determine whether and when to complete these transactions.

On June 3, 2011, WPX established a new $1.5 billion five-year senior unsecured credit facility which became effective on November 1, 2011**.** (See Note 9 of Notes to Consolidated Financial Statements). We expect that WPX will also issue senior unsecured notes in conjunction with the reorganization plan. Our plan is to use a substantial portion of the net proceeds of the debt offering and IPO, if applicable, to repay a portion of our existing debt, along with any associated premiums.

In April 2011, our Board of Directors approved a regular quarterly dividend of $0.20 per share that we paid in June 2011, reflecting an increase of 60 percent compared to the $0.125 per share paid to our shareholders in each of the last four quarters. Additionally, in September 2011, we announced another dividend increase of 25 percent, beginning with a $0.25 per share quarterly dividend to be paid to investors in December 2011. As part of our new dividend policy, we plan to distribute substantially all of the cash distributions, net of applicable taxes, interest and costs, we receive from WPZ and, as a result, expect to increase our dividend payout by 10 to 15 percent annually.

Overview of Nine Months Ended September 30, 2011

Income (loss) from continuing operations attributable to The Williams Companies, Inc., for the nine months ended September 30, 2011, changed favorably by $2.1 billion compared to the nine months ended September 30, 2010. This change includes:

- The absence of a $1,003 million impairment charge related to goodwill at Exploration & Production, which is considered nondeductible for tax purposes, and $678 million of pre-tax charges associated with impairments of certain producing properties and acquired unproved reserves at Exploration & Production during the third quarter of 2010 (See Note 4 of Notes to Consolidated Financial Statements.)

- The absence of $648 million of pre-tax costs attributable to The Williams Companies, Inc., associated with our 2010 restructuring, including $606 million of early debt retirement costs. (See Note 4 of Notes to Consolidated Financial Statements.)

- A $199 million improvement in *operating income* at Williams Partners primarily due to higher NGL margins reflecting improved commodity prices. (See Results of Operations Segments, Williams Partners).

A $96 million improvement in *operating income* at Midstream Canada & Olefins due to higher NGL and olefin margins primarily from higher per-unit margins. (See Results of Operations Segments, Midstream Canada & Olefins).

Management s Discussion and Analysis (Continued)

Partially offsetting these favorable changes is an unfavorable change in Exploration & Production s operating income, in addition to the previously discussed impairments in 2010. (See Results of Operations Segments, Exploration & Production.)

In addition, the change in our *provision (benefit) for income taxes* includes:

- A $135 million net tax benefit recorded in 2011 associated with federal settlements and an international revised assessment. (See Note 5 of Notes to Consolidated Financial Statements.)
- A $66 million tax benefit recorded in the third quarter of 2011 associated with undistributed earnings of certain foreign operations that are now considered permanently reinvested. (See Note 5 of Notes to Consolidated Financial Statements.)

See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for the nine months ended September 30, 2011, increased $411 million compared to the nine months ended September 30, 2010, primarily due to the previously discussed improvements in operating income at Williams Partners and Midstream Canada & Olefins. *(*See Management s Discussion and Analysis of Financial Condition and Liquidity.)

Recent Events

In the first quarter of 2011, we changed our segment reporting structure to present our Canadian midstream and domestic olefins operations as a separate segment, Midstream Canada & Olefins. These operations were previously reported within Other. Prior periods have been recast to reflect this revised segment presentation.

In March 2011, Midstream Canada & Olefins announced a long-term agreement under which it will produce up to 17,000 barrels per day of ethane/ethylene mix for a chemical company in Alberta, Canada. We plan to expand two primary facilities located in Alberta to support the new agreement. (See Results of Operations Segments, Midstream Canada & Olefins.)

In May 2011, we contributed a 24.5 percent interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream) to WPZ in exchange for aggregate consideration of $297 million of cash, 632,584 limited partner units, and an increase in the capital account of its general partner to allow us to maintain our 2 percent general partner interest. WPZ funded the cash consideration for this transaction through its credit facility. The Williams Partners segment now holds a 49 percent interest in Gulfstream. We also own an additional 1 percent interest in Gulfstream, reported in Other. Prior period segment disclosures have not been adjusted for this transaction as the impact, which was less than 2.5 percent of Williams Partners segment profit for all periods presented, was not material.

In October 2011, Williams Partners executed an agreement with two significant producers to provide certain production handling services in the eastern deepwater Gulf of Mexico. We will design, construct and install a floating production system (Gulfstar FPS) that will have the capacity to handle 60 thousand barrels per day (Mbbls/d) of oil, up to 200 million cubic feet per day (MMcf/d) of natural gas, and the capability to provide seawater injection services. We expect Gulfstar FPS to be placed into service in 2014 and to be capable of serving as a central host facility for other deepwater prospects in the area. We may consider a joint venture partner for this project.

During the second quarter of 2011, we became a member of Oil Insurance Limited (OIL), an energy industry mutual insurance company which shares losses among its members. In addition to certain property insurance coverages, we also purchased named windstorm coverage from OIL. The OIL named windstorm insurance provides coverage up to $150 million per occurrence (60 percent of $250 million of losses in excess of $100 million), with an annual aggregate limit of $300 million and subject to a per-event shared limit aggregate of $750 million for all members.

Company Outlook

We believe we will continue to execute on our 2011 business plan and to capture attractive growth opportunities. Our structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions.

Table of Contents

Management s Discussion and Analysis (Continued)

Although energy prices and the broader economy declined during the third quarter of 2011, we still anticipate operating results for the full year of 2011 to be higher than 2010. However, these declines increase the risks of nonperformance of counterparties and impairments of our long-lived assets.

We continue to operate with a focus on Economic Value Added (EVA®)[1] and invest in our businesses in a way that meets customer needs and enhances our competitive position by:

- Continuing to invest in and grow our gathering and processing, interstate natural gas pipeline systems, and natural gas and crude oil drilling;
- Retaining the flexibility to adjust, to some extent, our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.

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

- Lower than anticipated energy commodity prices and margins;
- Lower than expected levels of cash flow from operations;
- Availability of capital;
- Counterparty credit and performance risk;
- Decreased drilling success at Exploration & Production;
- Decreased volumes from third parties served by our midstream businesses;
- General economic, financial markets, or industry downturn;
- 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 utilization of commodity hedging strategies, disciplined investment strategies, and maintaining at least $1 billion in consolidated liquidity from cash and cash equivalents and unused revolving credit facilities. In addition, we utilize master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

General

Unless indicated otherwise, the following discussion and analysis of results of operations and financial condition 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 our annual consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated June 1, 2011.

1 Economic Value Added® (EVA®) is a registered trademark of Stern Stewart & Co. This tool considers both financial earnings and a cost of capital in measuring performance. We look for opportunities to improve EVA® because we believe there is a strong correlation between EVA® improvement and creation of shareholder value.

Table of Contents

Critical Accounting Estimates

Impairments of Long-Lived Assets

We evaluate our long-lived assets for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value. Our computations utilize judgments and assumptions that include the estimated fair value of the asset, undiscounted future cash flows, discounted future cash flows, and the current and future economic environment in which the asset is operated.

We assess Exploration & Production s natural gas producing properties and acquired unproved reserve costs for impairment using estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of natural gas reserves quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and our estimate of an applicable discount rate commensurate with risk of the underlying cash flow estimates.

Due to a decline in forward natural gas prices during the third-quarter of 2011, we performed an assessment of certain Exploration & Production producing properties in the Powder River basin. This assessment considered interim updated reserve estimates that included 2011 additions to proved reserves. Based on this review, no impairment was required. The properties reviewed have a net book value of approximately $500 million as of September 30, 2011. These Powder River basin producing assets could be at risk of impairment if the weighted average forward price across all periods used in our cash flow estimates were to decline by approximately 6 percent on average, compared to forward prices at September 30, 2011, absent changes in other factors. If the results of our year end analysis of these properties require an impairment, it is reasonably possible that the amount of such charge could be at least $200 million.

A substantial portion of Exploration & Production s carrying value of other assets (primarily related to assets in the Piceance basin) could be at risk for impairment if forward prices across all future periods decline by at least 30 percent, on average, as compared to the prices at December 31, 2010.

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, 2011, compared to the three and nine months ended September 30, 2010. 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,			
	2011	2010	$ Change*	% Change*	2011	2010	$ Change*	% Change*
	(Millions)				(Millions)			
Revenues	$ 2,703	$ 2,300	+403	+18%	$ 7,947	$ 7,180	+767	+11%
Costs and expenses:								
Costs and operating expenses	2,025	1,748	-277	-16%	5,871	5,382	-489	-9%
Selling, general and administrative expenses	130	122	-8	-7%	401	356	-45	-13%
Impairments of goodwill and long-lived assets		1,681	+1,681	+100%		1,681	+1,681	+100%
Other (income) expense net		(4)	-4	-100%	2	(17)	-19	NM
General corporate expenses	54	43	-11	-26%	152	173	+21	+12%
Total costs and expenses	2,209	3,590			6,426	7,575		
Operating income (loss)	494	(1,290)			1,521	(395)		
Interest accrued net	(141)	(145)	+4	+3%	(437)	(433)	-4	-1%
Investing income net	49	68	-19	-28%	145	162	-17	-10%
Early debt retirement costs						(606)	+606	+100%
Other income (expense) net		(4)	+4	+100%	4	(12)	+16	NM
Income (loss) from continuing operations before income taxes	402	(1,371)			1,233	(1,284)		
Provision (benefit) for income taxes	55	(150)	-205	NM	194	(140)	-334	NM
Income (loss) from continuing operations	347	(1,221)			1,039	(1,144)		
Income (loss) from discontinued operations	(5)	(5)			(16)	(6)	-10	-167%
Net income (loss)	342	(1,226)			1,023	(1,150)		
Less: Net income attributable to noncontrolling interests	70	37	-33	-89%	203	121	-82	-68%
Net income (loss) attributable to The Williams Companies, Inc.	$ 272	$ (1,263)			$ 820	$ (1,271)		

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

Three months ended September 30, 2011 vs. three months ended September 30, 2010

The increase in *revenues* is primarily due to higher marketing and natural gas liquid (NGL) production revenues at Williams Partners due to higher average energy commodity prices. Additionally, fee revenues increased at Williams Partners due to higher gathering, processing, and transportation fee revenues. Midstream Canada & Olefins ethylene and propylene production revenues increased primarily due to higher average energy commodity prices. Additionally, higher Exploration & Production natural gas production revenues reflect an increase in production volumes sold and higher average natural gas prices, but were substantially offset by a decrease in gas management revenues associated with lower natural gas sales volumes.

The increase in *costs and operating expenses* is primarily due to increased costs associated with marketing purchases and operating costs at Williams Partners. The increased marketing purchases are primarily due to higher average energy commodity prices. In addition, ethylene and propylene feedstock costs increased at Midstream Canada & Olefins reflecting higher per-unit feedstock costs. Exploration expenses, gathering, processing, and transportation expenses, as well as depreciation, depletion and amortization expenses, increased at Exploration & Production. These increases at Exploration & Production were substantially offset by lower gas management expenses reflecting a decrease in natural gas purchase volumes.

Impairments of goodwill and long-lived assets in 2010 includes a $1,003 million impairment of goodwill and $678 million of impairments of certain producing properties and acquired unproved reserves at Exploration and Production. (See Note 4 of Notes to Consolidated Financial Statements.)

Other (income) expense net within *operating income* in 2010 includes $12 million of gains on sales of certain assets at Williams Partners.

The favorable change in *operating income (loss)* generally reflects the absence of impairments at Exploration & Production and an improved energy commodity price environment in 2011 compared to 2010.

The unfavorable change in *investing income net* is primarily due to the absence of a $30 million gain recognized in 2010 related to the sale of our interest in Accroven SRL at Other (see Management s Discussion and Analysis Other).

Provision (benefit) for income taxes changed unfavorably primarily due to pre-tax income in 2011 compared to pre-tax loss in 2010. See Note 5 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

The unfavorable change in *net income attributable to noncontrolling interests* reflects our decreased percentage of ownership of WPZ, which was 75 percent at September 30, 2011, compared to 77 percent at September 30, 2010, and higher operating results, primarily at WPZ.

Nine months ended September 30, 2011 vs. nine months ended September 30, 2010

The increase in *revenues* is primarily due to higher marketing and NGL production revenues at Williams Partners due to higher average energy commodity prices, partially offset by lower crude marketing volumes and a decrease in equity NGL production volumes. Additionally, fee revenues increased at Williams Partners primarily due to higher gathering, processing, and transportation fee revenues. Midstream Canada & Olefins ethylene and propylene production revenues increased primarily due to higher average energy commodity prices, partially offset by decreased propylene sales volumes, and higher Canadian NGL production revenues. Exploration & Production natural gas production revenues increased primarily due to higher volumes sold. These increases at Exploration & Production were more than offset by a decrease in Exploration & Production gas management revenues, reflecting a decrease in both volumes and average natural gas prices on physical natural gas sales.

The increase in *costs and operating expenses* is primarily due to increased costs associated with marketing purchases and operating costs at Williams Partners, partially offset by a decrease in NGL production costs. The higher marketing purchases are due to higher average energy commodity prices, partially offset by lower crude marketing volumes. Additionally, ethylene and propylene feedstock costs increased at Midstream Canada & Olefins reflecting higher per-unit feedstock costs. Exploration & Production incurred higher exploration expenses, gathering, processing, and transportation expenses, as well as depreciation, depletion and amortization expenses. These increases at Exploration & Production were more than offset by a decrease in both volumes and average natural gas prices associated with gas management activities at Exploration & Production.

The increase in *selling, general and administrative expenses* (SG&A) is primarily due to a $30 million increase at Exploration & Production related to higher employee-related expenses as a result of an increase in the number of employees and higher bad debt expense. Additionally, SG&A expenses at Williams Partners increased $14 million primarily due to higher employee-related expenses from gas pipeline operations.

Impairments of goodwill and long-lived assets in 2010 includes a $1,003 million impairment of goodwill and $678 million of impairments of certain producing properties and acquired unproved reserves at Exploration and Production. (See Note 4 of Notes to Consolidated Financial Statements.)

Other (income) expense net within *operating income* in 2011 includes $10 million related to the reversal of project feasibility costs from expense to capital at Williams Partners. (See Note 4 of Notes to Consolidated Financial Statements.)

Other (income) expense net within *operating income* in 2010 includes $18 million of involuntary conversion gains at Williams Partners and a $12 million gain on the sale of certain assets at Williams Partners.

35

Table of Contents

The decrease in g*eneral corporate expenses* is primarily due to the absence of $45 million of transaction costs incurred in 2010 associated with our strategic restructuring transaction, partially offset by costs incurred in 2011 related to the planned separation of our exploration and production business and higher employee-related expenses.

The favorable change in *operating income (loss)* generally reflects the absence of impairments at Exploration & Production, an improved energy commodity price environment in 2011 compared to 2010 and the absence of costs associated with the strategic restructuring in 2010, partially offset by higher operating costs and SG&A expenses.

The unfavorable change in *investing income net* is primarily due to $32 million of decreased gains recognized in 2011 related to the 2010 sale of our interest in Accroven SRL. (See Note 4 of Notes to Consolidated Financial Statements.) This decrease is partially offset by an increase of $13 million in equity earnings at Williams Partners related to an increased ownership interest in Overland Pass Pipeline Company LLC.

Early debt retirement costs in 2010 reflect costs related to corporate debt retirements associated with our first quarter 2010 strategic restructuring transaction, including premiums of $574 million.

Other (income) expense net below *operating income (loss)* in 2010 includes an $8 million environmental expense accrual associated with former refinery operations.

Provision (benefit) for income taxes changed unfavorably primarily due to pre-tax income in 2011 compared to pre-tax loss in 2010. See Note 5 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

The unfavorable change in *net income attributable to noncontrolling interests* reflects our decreased percentage of ownership of WPZ, which was 75 percent at September 30, 2011 compared to 77 percent at September 30, 2010 and higher operating results, primarily at WPZ.

Table of Contents

Management s Discussion and Analysis (Continued)

Results of Operations Segments

Williams Partners

Our Williams Partners segment includes WPZ, our consolidated master limited partnership, which includes two interstate natural gas pipelines, as well as investments in natural gas pipeline-related companies, which serve regions from the San Juan basin in northwestern New Mexico and southwestern Colorado to Oregon and Washington and from the Gulf of Mexico to the northeastern United States. WPZ also includes natural gas gathering and processing and treating facilities and oil gathering and transportation facilities located primarily in the Rocky Mountain and Gulf Coast regions of the United States. As of September 30, 2011, we own approximately 75 percent of the interests in WPZ, including the interests of the general partner, which is wholly owned by us, and incentive distribution rights.

Williams Partners ongoing strategy is to safely and reliably operate large-scale, interstate natural gas transmission and midstream infrastructures 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 and utilizing our low cost-of-capital to invest in growing markets, including the deepwater Gulf of Mexico, the Marcellus Shale, the western United States, and areas of increasing natural gas demand.

Williams Partners interstate transmission and related 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.

Overview of Nine Months Ended September 30, 2011

Significant events during 2011 include the following:

Gulfstream

In May 2011, an entity reported within Other contributed a 24.5 percent interest in Gulfstream to WPZ in exchange for aggregate consideration of $297 million of cash, 632,584 limited partner units, and an increase in the capital account of WPZ s general partner to maintain the 2 percent general partner interest.

Gulfstar FPS Deepwater Project

In October 2011, we executed agreements with two significant producers to provide production handling services for the Tubular Bells discovery located in the eastern deepwater Gulf of Mexico. The operator of the Tubular Bells field will utilize our proprietary floating-production system, Gulfstar FPS . We expect Gulfstar FPS to be capable of serving as a central host facility for other deepwater prospects in the area. We will design, construct, and install our Gulfstar FPS 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. The facility is a spar-based floating production system that utilizes a standard design approach that will allow customers to reduce their cycle time from discovery to first production. Construction is underway and the project is expected to be in service in 2014. We may consider a joint venture partner for this project.

Eagle Ford Shale

We have completed construction on a pipeline segment and related modifications necessary to reverse the flow of an existing Transco pipeline segment in southwest Texas, which began to gather south Texas gas to our Markham gas processing facility in the second quarter of 2011. In addition, we connected a third-party pipeline to our Markham plant during the third quarter that is delivering Eagle Ford Shale gas to the plant. We have executed both fee-based and keep whole processing agreements which we expect will push utilization of our Markham facility to full capacity. With the 2010 expansion, Markham is capable of processing 500 MMcf/d of gas with an NGL handling capacity of 45 Mbbls/d, subject to 25 Mbbls/d of available NGL take-away capacity until third-party pipeline connections are completed in early 2013.

Table of Contents

Management s Discussion and Analysis (Continued)

Perdido Norte

During the fourth quarter of 2010, both oil and gas production began to flow on a sustained basis through our Perdido Norte expansion, located in the western deepwater of the Gulf of Mexico. The project includes a 200 MMcf/d expansion of our onshore Markham gas processing facility and a total of 179 miles of deepwater oil and gas lines that expand the scale of our existing infrastructure. While annual production volumes are significantly lower than originally expected, they have increased each quarter of 2011 as producers have resolved several technical issues. With these improvements and with the addition of a new well, we anticipate volumes to continue to increase during the fourth quarter of 2011.

Overland Pass Pipeline

We became the operator of OPPL effective April 1, 2011. We own a 50 percent interest in OPPL which includes a 760-mile NGL pipeline from Opal, Wyoming, to the Mid-Continent NGL market center in Conway, Kansas, along with 150- and 125-mile extensions into the Piceance and Denver-Julesburg basins in Colorado, respectively. Our equity NGL volumes from our two Wyoming plants and our Willow Creek plant in Colorado are dedicated for transport on OPPL under a long-term shipping agreement. We plan to participate in the construction of a pipeline connection and capacity expansions, 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.

Marcellus Shale Gathering Asset Transition and Expansion

We assumed the operational activities for a gathering business in Pennsylvania s Marcellus Shale which we acquired at the end of 2010. This business includes 75 miles of gathering pipelines and two compressor stations. We expect gathered volumes to increase in the remainder of 2011 under our long-term dedicated gathering agreement for the seller s production. Additionally, engineering and construction activities continue on our Springville gathering pipeline which will connect the gathering system into the Transco pipeline. Our long-term dedicated gathering agreement was revised in the second quarter of 2011, such that we will ultimately provide capacity on the Springville pipeline of approximately 625 MMcf/d.

NGL equity volumes lower in third quarter

Our NGL equity sales volumes for the third quarter of 2011 were impacted by unplanned maintenance at our Opal plant along with a shutdown of a third-party fractionator for approximately 10 days for an expansion project. As a result of the fractionator shutdown, NGL take-away capacity from our western plants on OPPL was reduced, which forced our western plants to curtail ethane recoveries. To mitigate the impact, we maximized local sales, arranged for alternative temporary transportation and sales avenues, and rescheduled planned maintenance to take place concurrent with the shutdown.

Volatile commodity prices

Average per-unit NGL margins in the nine months ending September 30, 2011, are significantly higher than the same period in 2010, benefiting from a strong demand for NGLs resulting in higher NGL prices and slightly lower natural gas prices driven by abundant natural gas supplies.

NGL margins are defined as NGL revenues less any applicable 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.

Table of Contents

Management s Discussion and Analysis (Continued)

Outlook for the Remainder of 2011

The following factors could impact our business in 2011.

Commodity price changes

We expect our average per-unit NGL margins in 2011 to be higher than our rolling five-year average per-unit NGL margins. NGL price changes have historically tracked somewhat with changes in the price of 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 20 percent of our anticipated NGL sales volumes and an approximate corresponding portion of anticipated shrink gas requirements for the remainder of 2011. The combined impact of these energy commodity derivatives will provide a margin on the hedged volumes of $62 million.

Gathering, processing, and NGL sales volumes

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

We anticipate growth in our onshore businesses gas gathering and processing volumes as our infrastructure grows to support drilling activities in the Piceance and Appalachian basins. However, we anticipate no change or slight declines in basins in the Rocky Mountain and Four Corners areas due to reduced drilling activity. Due to the high proportion of fee-based processing agreements in the Piceance basin, we anticipate only a slight increase in NGL equity sales volumes.

Table of Contents

Management s Discussion and Analysis (Continued)

In our Gulf Coast businesses, we expect higher gas gathering, processing, and crude transportation volumes as our Perdido Norte pipelines move into a full year of operation and other in-process drilling is completed. Increases in permitting, subsequent to the 2010 drilling moratorium, give us reason to expect gradual increased drilling activities in the Gulf of Mexico. While we expect an overall increase in processed gas volumes in 2011, NGL equity volumes are expected to be lower as a major contract changed from keep-whole to percent-of-liquids processing.

Expansion projects

We expect to spend $1,020 million to $1,300 million in 2011 on capital projects and additional investments in partially owned equity investments, of which $321 million to $601 million remains to be spent. The recently completed or ongoing major expansion projects include:

85 North

An expansion of our existing natural gas transmission system from Alabama to various delivery points as far north as North Carolina. The cost of the project is estimated to be $222 million. Phase I was placed into service in July 2010 and increased capacity by 90 thousand dekatherms per day (Mdt/d). Phase II was placed into service in May 2011 and increased capacity by 219 Mdt/d.

Mobile Bay South II

Additional compression facilities and modifications to existing Mobile Bay line facilities in Alabama allowing natural gas transportation service to various southbound delivery points. In July 2010, we received approval from the FERC. Construction began in October 2010 and is estimated to cost $33 million. The project was placed into service in May 2011 and increased capacity by 380 Mdt/d.

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 $217 million. The project is expected to be phased into service in September 2012 and June 2013, with an increase in capacity of 225 Mdt/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 will increase capacity by 142 Mdt/d. We plan to place the project into service in November 2012.

Marcellus Shale

Additional gathering assets, including compression and dehydration, in the Marcellus Shale region of northeastern Pennsylvania, which is planned to provide approximately 1.25 Bcf/d of gathering capacity. Various compression and dehydration projects to increase the capacity of the acquired gathering system to approximately 550 MMcf/d are complete; however, volumes are constrained until take-away capacity is in service.

Our Springville pipeline, which is expected to be completed in the fourth quarter of 2011, will allow full use of the current capacity. In conjunction with a long-term agreement with a significant producer, we are constructing and will operate the Springville pipeline, a 33-mile, 24-inch diameter natural gas gathering pipeline, connecting a portion of our gathering assets into the Transco pipeline. The first phase of the Springville project is expected to be completed in the fourth quarter of 2011 and will allow us to deliver approximately 300 MMcf/d to Transco. Expansions to the Springville compression facilities in 2012 will eventually increase the capacity to approximately 625 MMcf/d.

Construction of a new non-contiguous gathering system is complete and was placed into service in October 2011. This system currently has the capacity to deliver approximately 50 MMcf/d into a third-party interstate pipeline via another third-party gathering system. We will continue to expand this gathering system to a planned capacity of 150 MMcf/d.

Laurel Mountain

Capital to be invested within our Laurel Mountain Midstream, LLC (Laurel Mountain) equity investment, also in the Marcellus Shale region, to enable the rapid expansion of our gathering system including the initial stages of projects that are planned to provide approximately 1.5 Bcf/d of gathering capacity and 1,400 miles of gathering lines, including 400 new miles of 6-inch to 24-inch diameter pipeline. The initial phase of our Shamrock compressor station went in service during the first quarter of 2011, providing 30 MMcf/d of additional capacity, with another 150 MMcf/d expected to be available in the first quarter of 2012. This compressor station is expandable to 350 MMcf/d and will likely be the largest central delivery point out of the Laurel Mountain system. In other separate compression projects, an additional 20 MMcf/d of capacity began operating in the second quarter of 2011 and we continue to progress on further additions. In the third quarter of 2011, Laurel Mountain executed agreements with Exploration & Production to provide gathering services in Westmoreland County, Pennsylvania beginning in the second quarter of 2012.

Parachute

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

We have several other proposed projects to meet customer demands in addition to the various in-progress expansion projects previously discussed. Subject to regulatory approvals, construction of some of these projects could begin in the remainder of 2011.

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.

41

Table of Contents

Management s Discussion and Analysis (Continued)

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 $76 million, which is expected to be spent in 2011, 2012, and the first half of 2013. This estimate is subject to change as work progresses and additional information becomes known. As of September 30, 2011, we have incurred $31 million in abandonment costs. 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 11 of Notes to Consolidated Financial Statements.)

For the three and nine months ended September 30, 2011, we incurred $6 million and $13 million, respectively, of expenses related primarily to assessment and monitoring costs to ensure the safety of the surrounding area.

Period-Over-Period Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
		(Millions)		
Segment revenues	$ 1,673	$ 1,327	$ 4,923	$ 4,217
Segment profit	$ 471	$ 371	$ 1,379	$ 1,156

Three months ended September 30, 2011 vs. three months ended September 30, 2010

The increase in *segment revenues* includes:

A $184 million increase in marketing revenues primarily due to higher average NGL and crude prices. These changes are substantially offset by similar changes in marketing purchases.

A $102 million increase in revenues associated with our equity NGLs reflecting an increase of $96 million associated with a 43 percent increase in average NGL per-unit prices, and a $6 million increase in revenues associated with a 1 percent increase in NGL volumes.

A $39 million increase in fee revenues primarily due to a minimum volume commitment fee and new volumes transported on our Perdido Norte gas and oil pipelines in the deepwater of the western Gulf of Mexico which went into service in late 2010, new gathering fee revenues from our gathering assets in the Marcellus Shale in northeastern Pennsylvania acquired in late 2010, and higher fees in the Piceance basin as a result of an agreement with Exploration & Production executed in November 2010.

An $18 million increase in natural gas transportation revenues associated with gas pipeline expansion projects placed into service in 2010 and 2011.

Segment costs and expenses increased $262 million, including:

A $181 million increase in marketing purchases primarily due to higher average NGL and crude prices. These changes are offset by similar changes in marketing revenues.

A $58 million increase in operating costs reflecting $35 million higher maintenance expenses including unplanned maintenance during the third quarter of 2011, along with planned maintenance performed during the previously mentioned outage of a third-party fractionator. In addition, depreciation expense is $15 million higher primarily due to our new Perdido Norte pipelines, increased depreciation of our Lybrook plant which is scheduled to be idled at the end of 2011 when the gas will be redirected to our Ignacio plant, and our Echo Springs expansion which went into service in late 2010.

A $19 million unfavorable change related to gains recognized in 2010, including the sale of certain assets in Colorado s Piceance basin and involuntary conversion gains due to insurance recoveries in excess of the carrying value of our Gulf assets which were damaged by Hurricane Ike in 2008.

Table of Contents

Management s Discussion and Analysis (Continued)

The increase in *segment profit* includes:

- A $98 million increase in NGL margins primarily due to increased average NGL per-unit prices.

- A $39 million increase in fee revenues as previously discussed.

- An $18 million increase in natural gas transportation revenues as previously discussed.

- A $16 million increase in equity earnings primarily due to higher Discovery equity earnings from higher NGL prices, the acquisition of an additional interest in Gulfstream in May 2011, and higher OPPL equity earnings as a result of our purchase of an increased ownership interest in September 2010.

- A $58 million increase in operating costs as previously discussed.

- A $19 million unfavorable change related to gains recognized in 2010 as previously discussed.

Nine months ended September 30, 2011 vs. nine months ended September 30, 2010

The increase in *segment revenues* includes:

- A $418 million increase in marketing revenues primarily due to higher average NGL and crude prices, partially offset by lower crude volumes. These changes are substantially offset by similar changes in marketing purchases.

- A $158 million increase in revenues from our equity NGLs reflecting an increase of $185 million associated with a 23 percent increase in average NGL per-unit sales prices, partially offset by a decrease of $27 million associated with a 4 percent decrease in equity NGL volumes.

- A $73 million increase in fee revenues primarily due to higher gathering and processing fee revenues. In the Piceance basin, higher fees are primarily a result of an agreement with Exploration & Production executed in November 2010. In addition, we are generating fees from new volumes on our gathering assets in the Marcellus Shale in northeastern Pennsylvania, which we acquired at the end of 2010 and on our Perdido Norte gas and oil pipelines in the deepwater of the western Gulf of Mexico, which went into service in late 2010. These increases are partially offset by a decline in gathering and transportation fees in the deepwater of the eastern Gulf of Mexico, the Four Corners, and southwest Wyoming areas primarily due to natural field declines.

- A $41 million increase in natural gas transportation revenues associated with gas pipeline expansion projects placed into service in 2010 and 2011.

A $19 million increase in revenues from higher system management gas sales in 2011 compared to 2010. These are offset in *cost and operating expenses*.

Segment costs and expenses increased $507 million, including:

A $387 million increase in marketing purchases primarily due to higher average NGL and crude prices, partially offset by lower crude volumes. These changes are offset by similar changes in marketing revenues.

A $112 million increase in operating costs reflecting $66 million higher maintenance expenses, including unplanned maintenance in the third quarter of 2011, planned maintenance performed during the previously mentioned outage of a third-party fractionator, maintenance expenses for our gathering assets in northeastern Pennsylvania acquired at the end of 2010, and higher property insurance expense. In addition, depreciation expense is $39 million higher primarily due to our new Perdido Norte pipelines, our Echo Springs expansion which went into service in late 2010, and increased depreciation of our Lybrook plant which is scheduled to be idled at the end of 2011 when the gas will be redirected to our Ignacio plant.

A $30 million unfavorable change related to gains recognized in 2010 including involuntary conversion gains due to insurance recoveries in excess of the carrying value of our Ignacio plant which was damaged by a fire in 2007 and Gulf Coast assets which were damaged by Hurricane Ike in 2008 and gains associated with sales of certain assets in Colorado s Piceance basin.

Table of Contents

Management s Discussion and Analysis (Continued)

A $19 million increase in costs from higher system management gas costs in 2011 compared to 2010. These are offset in *segment revenues*.

A $14 million increase in *selling, general, and administrative expenses* primarily due to higher employee-related expenses.

A $40 million decrease in costs associated with our equity NGLs reflecting a decrease of $22 million associated with a 7 percent decrease in average natural gas prices and an $18 million decrease reflecting lower equity NGL volumes.

A $10 million decrease in costs for the reversal of project feasibility costs from expense to capital, associated with a natural gas pipeline expansion project, upon determining that the related project was probable of development. These costs will be included in the capital costs of the project, which we believe are probable of recovery through the project rates.

The increase in *segment profit* includes:

A $198 million increase in NGL margins primarily due to favorable commodity price changes.

A $73 million increase in fee revenues as previously discussed.

A $41 million increase in natural gas transportation revenues as previously discussed.

A $31 million increase in margins related to the marketing of NGLs and crude.

A $24 million increase in equity earnings primarily due to the acquisition of an additional interest in Gulfstream in May 2011 and higher OPPL equity earnings as a result of our purchase of an increased ownership interest in September 2010.

A $10 million reversal of project feasibility costs from expense to capital as previously discussed.

A $112 million increase in operating costs as previously discussed.

A $30 million unfavorable change related to gains recognized in 2010 as previously discussed.

A $14 million increase in *selling, general, and administrative expenses* primarily due to higher employee-related expenses.

Exploration & Production

Our Exploration & Production segment is engaged in the exploitation and development of long-life unconventional properties. We are focused on profitably exploiting our significant natural gas reserve base and related NGLs in the Piceance basin of the Rocky Mountain region, and on developing and growing our position in the Bakken Shale oil play in North Dakota and our Marcellus Shale natural gas position in Pennsylvania. Our other areas of domestic operations include the Powder River basin in Wyoming and the San Juan basin in the southwestern United States. In addition, we own a 69 percent controlling ownership interest in Apco Oil and Gas International Inc. (Apco), which holds oil and gas concessions in Argentina and Colombia and trades on the NASDAQ Capital Market under the symbol APAGF.

In addition to our exploration and development activities, we engage in natural gas sales and marketing. Our sales and marketing activities include the sale of our natural gas and oil production, in addition to third-party purchases and sales of natural gas, including sales to Williams Partners for use in its midstream business. Our sales and marketing activities include the management of various natural gas related contracts such as transportation, storage and related hedges. We also sell natural gas purchased from working interest owners in operated wells and other area third-party producers. We primarily engage in these activities to enhance the value received from the sale of our natural gas and oil production. Revenues associated with the sale of our domestic production are recorded in domestic production revenues. The revenues and expenses related to other marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

Management s Discussion and Analysis (Continued)

As previously disclosed, WPX filed its initial registration statement with the Securities and Exchange Commission on April 29, 2011 and the fifth amendment on October 28, 2011. The operating results reported by WPX will differ from those of Exploration & Production due to differences associated with reporting WPX on a stand-alone basis.

Overview of Nine Months Ended September 30, 2011

Highlights of the comparative periods, primarily related to our production activities, include:

	For the nine months ended September 30,		
	2011	2010	% Change
Average daily domestic production (MMcfe)	1,211	1,105	+10%
Average daily total production (MMcfe)	1,267	1,160	+9%
Domestic production realized average price ($/Mcfe)(1)	$ 5.44	$ 5.30	+3%
Capital expenditures and acquisitions ($ millions)	$ 1,092	$ 1,477	-26%
Domestic production revenues ($ millions)	$ 1,798	$ 1,599	+12%
Segment revenues ($ millions)	$ 2,992	$ 3,063	-2%
Segment profit (loss) ($ millions)	$ 193	$ (1,404)	N/A

(1) Realized average prices include market prices, net of fuel and shrink and hedge gains and losses. The realized hedge gain per Mcfe was $0.65 and $0.73 for the first nine months of 2011 and 2010, respectively.

During the first quarter, we initiated a formal process to pursue the divestiture of our holdings in the Arkoma basin. Due to this decision, we have reported our Arkoma results of operations as discontinued operations. Our daily production is approximately 9 MMcfd, or less than one percent of our domestic and international production.

During late 2010 and 2011, we incurred $11 million of exploratory drilling costs in connection with a Marcellus Shale well in Columbia County, Pennsylvania. Results have been inconclusive and raise substantial doubt about the economic and operational viability of the well. As a result, the costs associated with this well were expensed as exploratory dry hole costs at September 30, 2011. Further, we assessed the impact of this well on our ability to recover the remaining lease acquisition costs associated with the acreage in Columbia County. During the nine months ended September 30, 2011, we recorded a $50 million write-off of leasehold costs associated with certain portions of our Columbia County acreage that we do not plan to develop. The acreage in Columbia County represents approximately 21 percent of our total undeveloped acreage in the Marcellus Shale. Prior to the write-off, the total carrying value of the undeveloped leasehold costs associated with our Columbia County acreage was $75 million, or 11 percent of our total carrying value for undeveloped leasehold costs in the Marcellus Shale.

Outlook for the Remainder of 2011

We believe that our portfolio of reserves provides an opportunity to continue to grow in our strategic areas, including the Piceance basin, the Marcellus Shale and the Bakken Shale positions. We are focused on developing a more balanced portfolio that may include a larger portion of oil and NGL reserves and production than we have historically maintained. Currently, we expect 2011 capital expenditures between $1.35 billion and $1.55 billion. We expect to maintain three to five drilling rigs in our newly acquired Bakken Shale properties with related capital expenditures expected to be between $200 million and $300 million. Additionally, we expect capital expenditures between $200 million and $300 million in our Appalachian basin. The remaining amount of capital expenditures will primarily reflect development drilling in the Piceance basin. We also expect annual average daily total production to increase approximately 9 percent over 2010.

Risks to achieving our expectations include unfavorable energy commodity price movements which are impacted by numerous factors, including weather conditions, domestic natural gas, oil and NGL production levels and demand. A significant decline in natural gas, oil and NGL prices would impact these expectations for 2011, although the impact would be partially mitigated by our hedging program, which hedges a significant portion of our expected production. In addition, changes in laws and regulations may impact our development drilling program.

45

Table of Contents

Management s Discussion and Analysis (Continued)

Powder River Producing Properties

Due to a decline in forward natural gas prices during the third-quarter of 2011, we performed an assessment of certain producing properties in the Powder River basin. This assessment considered interim updated reserve estimates that included 2011 additions to proved reserves. Based on this review, no impairment was required. The properties reviewed have a net book value of approximately $500 million as of September 30, 2011. These Powder River basin producing assets could be at risk of impairment if the weighted average forward price across all periods used in our cash flow estimates were to decline by approximately 6 percent on average, compared to prices at September 30, 2011, absent changes in other factors. If the results of our year end analysis of these properties require an impairment, it is reasonably possible that the amount of such charge could be at least $200 million.

Commodity Price Risk Strategy

To manage the commodity price risk and volatility of owning producing natural gas and oil properties, we enter into derivative contracts for a portion of our future production. For the remainder of 2011, we have the following contracts for our daily domestic production, shown at weighted average volumes (natural gas in billions of Btu -BBtu) and basin-level weighted average prices:

		Remainder of 2011 Natural Gas			
Natural Gas		**Volume (BBtu/d)**	**Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars**		
Collar agreements	Rockies	45	$	5.30	$7.10
Collar agreements	San Juan	90	$	5.27	$7.06
Collar agreements	Mid-Continent	80	$	5.10	$7.00
Collar agreements	Southern California	30	$	5.83	$7.56
Collar agreements	Northeast	30	$	6.50	$8.14
Fixed price at basin swaps		395	$		5.25

	Remainder of 2011 Crude Oil		
Crude Oil	**Volume (Bbls/d)**	**Weighted Average Price ($/Bbl)**	
WTI Crude Oil fixed-price	4,500	$	96.56

46

Table of Contents

Management s Discussion and Analysis (Continued)

The following is a summary of our agreements and contracts for daily domestic production shown at weighted average volumes and basin-level weighted average prices for the three and nine months ended September 30, 2011 and 2010:

		Three months ended September 30,							
		2011				2010			
Natural Gas		**Volume (BBtu/d)**	**Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars**			**Volume (BBtu/d)**	**Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars**		
Collar agreements	Rockies	45	$	5.30	$7.10	100	$	6.53	$8.94
Collar agreements	San Juan	90	$	5.27	$7.06	230	$	5.75	$7.84
Collar agreements	Mid-Continent	80	$	5.10	$7.00	105	$	5.37	$7.41
Collar agreements	Southern California	30	$	5.83	$7.56	45	$	4.80	$6.43
Collar agreements	Northeast and other	30	$	6.50	$8.14	30	$	5.66	$6.89
NYMEX and basis fixed-price		375	$		5.19	120	$		4.35

Crude Oil	**Volume (Bbls/d)**	**Weighted Average Price ($/Bbl)**		**Volume (Bbls/d)**	**Weighted Average Price ($/Bbl)**
WTI Crude Oil fixed-price	3,995	$	96.04		

		Nine months ended September 30,							
		2011				2010			
Natural Gas		**Volume (BBtu/d)**	**Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars**			**Volume (BBtu/d)**	**Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars**		
Collar agreements	Rockies	45	$	5.30	$7.10	100	$	6.53	$8.94
Collar agreements	San Juan	90	$	5.27	$7.06	233	$	5.74	$7.82
Collar agreements	Mid-Continent	80	$	5.10	$7.00	105	$	5.37	$7.41
Collar agreements	Southern California	30	$	5.83	$7.56	45	$	4.80	$6.43
Collar agreements	Northeast and other	30	$	6.50	$8.14	27	$	5.63	$6.87
NYMEX and basis fixed-price		365	$		5.21	120	$		4.39

Crude Oil	**Volume (Bbls/d)**	**Weighted Average Price ($/Bbl)**		**Volume (Bbls/d)**	**Weighted Average Price ($/Bbl)**
WTI Crude Oil fixed-price	2,916	$	95.53		

Additionally, we utilize contracted pipeline capacity to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We also hold a long-term obligation to deliver on a firm basis 200,000 MMbtu per day of gas at monthly pricing to a buyer at the White River Hub (Greasewood-Meeker, CO), which is the major market hub exiting the Piceance basin. Our interests in the Piceance basin hold sufficient reserves to meet this obligation which expires in 2014.

Table of Contents

Management s Discussion and Analysis (Continued)

Period-Over-Period Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	(Millions)			
Segment revenues:				
Domestic production revenues	$ 633	$ 526	$ 1,798	$ 1,599
Gas management revenues	347	436	1,089	1,357
Hedge ineffectiveness and mark-to-market gains and losses	12	16	20	25
Other revenues	30	27	85	82
Total segment revenues	$ 1,022	$ 1,005	$ 2,992	$ 3,063
Segment profit (loss)	$ 48	$ (1,630)	$ 193	$ (1,404)

Three months ended September 30, 2011 vs. three months ended September 30, 2010

The increase in total *segment revenues* is primarily due to a $107 million increase in domestic production revenues which reflects an increase of $69 million associated with a 13 percent increase in production volumes sold, and an increase of $38 million associated with a 6 percent increase in realized average prices reflecting all products (on an Mcfe basis) including the effect of hedges. Excluding the impact of hedges, production revenues would have increased $127 million from the third quarter of 2010 to the third quarter of 2011. Production revenues in the third quarters of 2011 and 2010 include approximately $108 million and $60 million, respectively, related to natural gas liquids and approximately $61 million and $14 million, respectively, related to crude and condensate. The increase in NGL revenues is primarily due to higher volumes and prices in our Piceance basin primarily processed by Williams Partners Willow Creek facility. The increase in crude and condensate is primarily related to our Bakken properties which were acquired in the fourth quarter of 2010.

Partially offsetting the increase is an $89 million decrease in gas management revenues primarily due to a decrease in physical natural gas revenue as a result of a 21 percent decrease in natural gas sales volumes. Gas management revenues are primarily related to gas sales associated with our transportation and storage contracts and are significantly offset by a similar decrease in *segment costs and expenses*.

Total *segment costs and expenses* decreased $1,661 million, primarily due to the following:

- The absence of $1,681 million of impairments to property and goodwill recognized in 2010. During the third quarter 2010, we fully impaired our goodwill in the amount of $1 billion. Additionally, we recorded a $503 million impairment charge related to the capitalized costs of our Barnett Shale properties and a $175 million impairment charge related to capitalized costs of acquired unproved reserves in the Piceance Highlands, which were acquired in 2008;

- $87 million decrease in gas management expenses primarily due to a 21 percent decrease in natural gas purchase volumes. This decrease is primarily related to the gas purchases associated with our previously discussed transportation and storage contracts and is partially offset by a similar decrease in *segment revenues*. Gas management expenses in third quarter 2011 and 2010 include $10 million and $10 million, respectively, related to charges for unutilized pipeline capacity.

Partially offsetting the decreases are increases primarily due to the following:

$47 million higher exploration expense primarily due to the previously mentioned dry hole and leasehold write-offs of $61 million in the Marcellus shale, partially offset with the absence of $15 million in dry hole charges associated with our Paradox basin recognized in 2010;

$25 million higher gathering, processing, and transportation expenses partially as a result of an increase in transportation costs associated with higher production volumes and higher rates charged on gathering and processing associated with certain gathering and processing assets in the Piceance basin that were transferred to WPZ in the fourth quarter of 2010 and higher volumes processed at Williams Partners Willow Creek plant;

$30 million higher depreciation, depletion and amortization expenses primarily due to higher production volumes;

$9 million higher lease and other operating expenses primarily due to increased workover, water management and maintenance activity.

Table of Contents

Management s Discussion and Analysis (Continued)

The $1,678 million increase in s*egment profit* is primarily due to the absence in 2011 of impairments and writeoffs that occurred in 2010, higher oil and gas prices and higher production volumes, partially offset by the previously discussed increases in *segment costs and expenses.*

Nine months ended September 30, 2011 vs. nine months ended September 30, 2010

The $71 million decrease in total *segment revenues* reflects a $268 million decrease in gas management revenue primarily due to a decrease in physical natural gas revenue as a result of a 15 percent decrease in natural gas sales volumes and a 6 percent decrease in average prices on physical natural gas sales. Gas management revenues are primarily related to gas sales associated with our transportation and storage contracts and are significantly offset by a similar decrease in *segment costs and expenses*.

Partially offsetting the decrease is a $199 million increase in domestic production revenues primarily due to an increase of $153 million associated with a 10 percent increase in production volumes sold, and an increase of $46 million associated with a 3 percent increase in realized average prices (on an Mcfe basis) including the effect of hedges. Excluding the impact of hedges, production revenues would have increased $204 million from 2010 to 2011. Production revenues in 2011 and 2010 include approximately $323 million and $196 million, respectively, related to natural gas liquids and approximately $160 million and $39 million, respectively, related to crude and condensate. The increase in NGL revenues is primarily due to higher volumes and prices in our Piceance basin primarily processed by Williams Partners Willow Creek facility. The increase in crude and condensate is primarily related to our Bakken production which was acquired in the fourth quarter of 2010. The increase in crude oil and condensate offsets the decrease in realized natural gas prices.

Total *segment costs and expenses* decreased by $1,667 million primarily due to the following:

- The absence of $1,681 million of impairments to property and goodwill in 2010.

- $264 million decrease in gas management expenses primarily due to a 15 percent decrease in natural gas purchase volumes and a 5 percent decrease in average prices on physical natural gas purchases. This decrease is primarily related to the gas purchases associated with our previously discussed transportation and storage contracts and is partially offset by a similar decrease in *segment revenues*. Gas management expenses in 2011 and 2010 include $28 million and $35 million, respectively, related to charges for unutilized pipeline capacity;

Partially offsetting the decreases are increases primarily due to the following:

- $81 million higher gathering, processing, and transportation expenses partially as a result of an increase in transportation costs associated with higher production volumes and higher rates charged on gathering and processing associated with certain gathering and processing assets in the Piceance basin that were transferred to WPZ in the fourth quarter of 2010 and higher volumes processed at Williams Partners Willow Creek plant. Additionally, gathering, processing and transportation expenses reflect charges of $14 million in 2011 related to the correction of an error associated with our estimate of accrued minimum annual charges for compression service contracts in the Powder River basin;

- $75 million higher exploratory expenses associated with the previously discussed dry hole and leasehold write-offs in the Marcellus shale coupled with increased leasehold amortization costs associated with prior period leasehold acquisitions. Partially off-setting these increases is the absence of $15 million in dry hole charges associated with our Paradox basin recognized in 2010;

- $63 million higher depreciation, depletion and amortization expenses primarily due to higher production volumes;

$33 million higher lease and other operating expenses primarily due to increased workover, water management and maintenance activity.

Table of Contents

Management s Discussion and Analysis (Continued)

- $30 million higher SG&A expense due primarily to higher wages, salary and benefits costs as a result of an increase in the number of employees and higher bad debt expense

Segment profit increased by $1,597 million primarily due to the absence in 2011 of impairments that occurred in 2010, higher oil and gas prices and higher production volumes, partially offset by the previously discussed increases in *segment costs and expenses.*

Midstream Canada & Olefins

Our Midstream Canada & Olefins segment includes our oil sands off-gas processing plant near Fort McMurray, Alberta, our NGL/olefin fractionation facility and butylene/butane splitter (B/B splitter) facility at Redwater, Alberta, our NGL light-feed olefins cracker in Geismar, Louisiana along with associated ethane and propane pipelines, and our refinery grade propylene splitter in Louisiana. The products we produce are: NGLs, ethylene, propylene, and other co-products. Our NGL products include: propane, normal butane, isobutane/butylene (butylene), and condensate. Prior to the operation of the B/B splitter, which was placed in service in August 2010, we also produced and sold butylene/butane mix product (B/B mix) which is now separated and sold as butylene and normal butane.

Overview of Nine Months Ended September 30, 2011

Segment profit for the nine months ended September 30, 2011 improved compared to the prior year primarily due to higher production margins on Canadian B/B mix products as a result of the B/B splitter, on Geismar ethylene, the co-products butadiene and debutanized aromatic concentrate (DAC), and on Canadian propane and propylene.

Significant events for 2011

We signed a long-term agreement to initially produce 10,000 barrels per day (bbls/d) of ethane/ethylene mix for a third-party customer. We expect that we will ultimately increase our production of ethane/ethylene mix to 17,000 bbls/d and we expect to complete our expansions necessary to produce the initial barrels in the first quarter of 2013.

Outlook for the Remainder of 2011

The following factors could impact our business in 2011.

Commodity price changes

We believe average per-unit margins for 2011 will increase over 2010 levels. Margins are highly dependent upon continued demand within the global economy. 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 because of our NGL-based olefins production.

Allocation of capital to projects

We expect to spend $300 million to $400 million in 2011 on capital projects, of which $136 million to $236 million remains to be spent. The major expansion projects include:

- An expansion of our Geismar olefins production facility which will increase the facility s ethylene production capacity by 600 million pounds per year to a new annual capacity of 1.95 billion pounds. We have begun the detailed engineering phase and expect to complete the expansion in the latter part of 2013.

The Ethane Recovery project which is an expansion in our Canadian facilities that will allow us to produce ethane/ethylene mix from our operations that process off-gas from the Alberta oil sands. We will modify our oil sands off-gas extraction plant near Fort McMurray, Alberta, and construct a de-ethanizer at our Redwater fractionation facility. Our de-ethanizer will enable us to initially produce approximately 10,000 bbls/d of ethane/ethylene mix. We have signed a long-term contract to provide the ethane/ethylene mix to a third-party customer. Pre-construction activities are in progress and we expect to complete the expansions and begin producing ethane/ethylene mix in the first quarter of 2013.

Table of Contents

Management s Discussion and Analysis (Continued)

The Boreal Pipeline project which is a 12-inch diameter pipeline in Canada that will transport recovered NGLs and olefins from our extraction plant in Fort McMurray to our Redwater fractionation facility. The pipeline will have sufficient capacity to transport additional recovered liquids in excess of those from our current agreements. Construction is in progress and we anticipate an in-service date in the second quarter of 2012.

Period-Over-Period Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	(Millions)			
Segment revenues	$ 326	$ 232	$ 989	$ 761
Segment profit	$ 73	$ 42	$ 219	$ 123

Three months ended September 30, 2011 vs. three months ended September 30, 2010

Segment revenues increased primarily due to:

$41 million higher ethylene production sales revenues primarily due to 48 percent higher average per-unit sales prices.

$25 million higher NGL production revenues primarily resulting from higher average per-unit NGL sales prices, a change in product mix, and 69 percent higher sales volumes on our Canadian B/B mix products primarily resulting from increased production.

$11 million higher propylene production revenues due to $25 million higher revenues from 47 percent higher average per-unit sales prices, partially offset by $14 million lower revenues primarily resulting from lower volumes in our Louisiana refinery grade propylene splitter. The 35 percent lower Louisiana propylene splitter sales volumes were primarily due to third-party supply constraints, partially offset by sales from inventory. The impact of the lower propylene splitter sales was substantially offset by similar changes in related costs.

$11 million higher butadiene and DAC production sales revenues primarily due to higher average per-unit sales prices.

Segment costs and expenses increased $63 million primarily as a result of:

$50 million higher ethylene and propylene feedstock costs from higher average per-unit feedstock costs.

$14 million higher operating and maintenance expenses resulting primarily from scheduled third-quarter 2011 maintenance at our Canadian facilities.

$6 million higher NGL feedstock costs primarily from higher average per-unit feedstock costs.

These increases were partially offset by $11 million lower propylene feedstock costs primarily resulting from the lower sales volumes at our Louisiana refinery grade splitter described above.

Segment profit increased primarily due to:

- $17 million higher Canadian propylene and propane production margins primarily from higher per-unit margins.

- $15 million higher Canadian NGL production margins from the B/B mix products resulting from higher average per-unit margins primarily driven by higher NGL sales prices, a change in product mix, and higher volumes.

Table of Contents

Management s Discussion and Analysis (Continued)

$12 million higher Geismar ethylene and butadiene production margins resulting primarily from increased per-unit margins. These increases were partially offset by $14 million higher operating and maintenance expenses.

Nine months ended September 30, 2011 vs. nine months ended September 30, 2010

Segment revenues increased primarily due to:

$81 million higher ethylene production sales revenues primarily due to 27 percent higher average per-unit sales prices on slightly higher volumes.

$69 million higher NGL production revenues primarily resulting from higher average per-unit sales prices driven by a change in our Canadian product mix, higher NGL sales prices, and 43 percent increased sales volumes on our Canadian B/B mix products primarily due to the impact of maintenance and operational issues discussed below. Through mid-2010, we sold B/B mix product, but in August 2010, we began producing and selling both butylene and butane that was produced by our new B/B splitter. The separated butylene and butane products receive higher values in the marketplace than the B/B mix sold previously.

$34 million higher propylene production revenues primarily due to $67 million higher revenues from 35 percent higher average per-unit sales prices, partially offset by $33 million lower revenues resulting primarily from 15 percent lower overall propylene production sales volumes. The lower sales volumes were primarily due to the net impact of the following:

28 percent lower volumes at our Louisiana refinery grade propylene splitter due to third-quarter 2011 supply constraints noted previously, second-quarter 2011 third-party storage, marketing and supply constraints, and first-quarter 2011 customer outages. The impact of the lower propylene splitter sales was substantially offset by similar changes in related costs.

20 percent higher propylene sales volumes at our Canadian facility primarily due to the absence of first-quarter 2010 operational issues at a third-party facility that provides our off-gas feedstock and lower reductions of volumes from scheduled maintenance in second and third quarters of 2011 as compared to 2010.

$22 million higher butadiene and DAC production sales revenues primarily due to higher average per-unit sales prices.

$21 million higher marketing revenues due to general increases in energy commodity prices on higher volumes. The higher marketing revenues were substantially offset by similar changes in marketing purchases described below.

Segment costs and expenses increased $132 million primarily as a result of:

$57 million higher ethylene feedstock costs resulting primarily from higher average per-unit feedstock costs.

$18 million increased marketing purchases due to general increases in energy commodity prices on higher volumes. The increased marketing purchases substantially offset similar changes in marketing revenues.

$15 million higher operating and maintenance expenses primarily resulting from scheduled third-quarter 2011 maintenance at our Canadian facilities.

$12 million higher NGL feedstock costs primarily due to higher average per-unit feedstock costs on certain products and increased volumes on our Canadian B/B mix products primarily due to reduced maintenance and operational issues.

Table of Contents

Management s Discussion and Analysis (Continued)

$11 million higher propylene feedstock costs primarily resulting from $36 million higher costs from 26 percent higher average per-unit feedstock costs, partially offset by $25 million lower propylene feedstock volumes primarily from the lower volumes at our Louisiana refinery grade splitter described above.

The absence of a $6 million favorable customer settlement in 2010.

Segment profit increased primarily due to:

$37 million higher Canadian NGL production margins on the B/B mix products primarily resulting from higher average per-unit margins primarily driven by a change in product mix, higher NGL sales prices, and higher volumes.

$25 million higher Canadian propylene production margins resulting from 49 percent higher per-unit margins and 20 percent higher volumes.

$24 million higher Geismar ethylene production margins primarily due to 28 percent higher per-unit margins on slightly higher sales volumes.

$20 million higher Canadian propane production margins due to 52 percent higher per-unit margins and 8 percent higher volumes.

$17 million higher Geismar butadiene and DAC production margins resulting from higher average per-unit margins.

These increases were partially offset by $15 million higher operating and maintenance expenses and the absence of a $6 million favorable customer settlement in 2010.

Other

Other includes other business activities that are not operating segments as well as corporate operations.

Period-Over-Period Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	(Millions)			
Segment revenues	$ 6	$ 6	$ 19	$ 17
Segment profit	$ 1	$ 38	$ 23	$ 63

Three months ended September 30, 2011 vs. three months ended September 30, 2010

The decrease in *segment profit* is primarily due to the absence of a $30 million gain recognized in third-quarter 2010 related to the sale of our interest in Accroven SRL in the second quarter.

Nine months ended September 30, 2011 vs. nine months ended September 30, 2010

The unfavorable change in s*egment profit* is primarily due to $32 million of decreased gains recognized in 2011 related to the 2010 sale of our interest in Accroven SRL. (See Note 4 of Notes to Consolidated Financial Statements.) We are pursuing collection of these past due amounts from PDVSA, as well as claims related to the 2009 expropriation of certain of our Venezuelan operations, which are reported as discontinued operations.

Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition and Liquidity

Outlook

For 2011, we expect operating cash flows to be stronger than 2010 levels. Lower-than-expected energy commodity prices would be somewhat mitigated by certain of our cash flow streams that are substantially insulated from short-term changes in commodity prices as follows:

- Firm demand and capacity reservation transportation revenues under long-term contracts from our gas pipelines;
- Hedged natural gas sales at Exploration & Production related to a significant portion of its production;
- Fee-based revenues from certain gathering and processing services in our midstream businesses.

We believe we have, or have access to, the financial resources and liquidity necessary to meet our requirements for working capital, capital and investment expenditures, and tax and debt payments while maintaining a sufficient level of liquidity. In addition to the previously discussed transactions related to our reorganization plan, we note the following for the year:

- We have announced a 25 percent increase to our dividend, with an expected quarterly dividend of $0.25 per share to be paid in December 2011. We expect to pay out substantially all of the cash distributions, net of applicable taxes, interest and costs, we receive from WPZ and expect 10 to15 percent annual dividend growth;
- We expect to maintain consolidated liquidity (which includes liquidity at WPZ) of at least $1 billion from *cash and cash equivalents* and unused revolving credit facilities;
- We expect WPZ to fund its $333 million of current debt maturities with new debt issuances;
- We expect to fund capital and investment expenditures, debt payments, dividends, and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, utilization of our revolving credit facilities, and proceeds from debt issuances and sales of equity securities as needed. Based on a range of market assumptions, we currently estimate our cash flow from operations will be between $3 billion and $3.2 billion in 2011;
- We expect capital and investment expenditures to total between $2.825 billion and $3.425 billion in 2011. Of this total, a significant portion of Williams Partners expected expenditures of $1.085 billion to $1.41 billion (which excludes its acquisition of a 24.5 percent interest in Gulfstream) are considered nondiscretionary to meet legal, regulatory, and/or contractual requirements or to fund committed growth projects. Exploration & Production s expected expenditures of $1.35 billion to $1.55 billion are considered primarily discretionary. Midstream Canada & Olefins expected expenditures of $300 million to $400 million are considered primarily nondiscretionary. See Results of Operations Segments, Williams Partners, Exploration & Production and Midstream Canada & Olefins for discussions describing the general nature of these expenditures.

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

Sustained reductions in energy commodity prices from the range of current expectations;

Lower than expected distributions, including incentive distribution rights, from WPZ. WPZ s liquidity could also be impacted by a lack of adequate access to capital markets to fund its growth;

Lower than expected levels of cash flow from operations from Exploration & Production and our other businesses.

Table of Contents

Management s Discussion and Analysis (Continued)

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. Our internal and external sources of consolidated liquidity include cash generated from our operations, cash and cash equivalents on hand, and our credit facilities. Additional sources of liquidity, if needed, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. These sources are available to us at the parent level and are expected to be available to certain of our subsidiaries, particularly equity and debt issuances from WPZ. WPZ is self-funding through its cash flows from operations, use of its credit facility, and its access to capital markets. Cash held by WPZ is available to us through distributions in accordance with the partnership agreement, which considers our level of ownership and incentive distribution rights. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

		September 30, 2011		
	Expiration	WPZ	WMB	Total
Available Liquidity			(Millions)	
Cash and cash equivalents		$ 143	$ 853 (1)	$ 996
Capacity available under our $900 million senior unsecured revolving credit facility (2)	June 3, 2016		900	900
Capacity available to WPZ under its $2 billion senior unsecured revolving credit facility (3)	June 3, 2016	1,600		1,600
		$ 1,743	$ 1,753	$ 3,496

(1) *Cash and cash equivalents* includes $5 million of funds received from third parties as collateral. The obligation for these amounts is reported as *accrued liabilities* on the Consolidated Balance Sheet. Also included is $535 million of *cash and cash equivalents* that is held by and expected to be utilized by certain subsidiary and international operations. The remainder of our *cash and cash equivalents* is primarily held in government-backed instruments.

(2) In June 2011, we replaced our existing $900 million unsecured revolving credit facility agreement that was scheduled to expire in May 2012 with a new $900 million five-year senior unsecured revolving credit facility agreement. At September 30, 2011, we are in compliance with the financial covenants associated with this new credit facility agreement (see Note 9 of Notes to Consolidated Financial Statements).

(3) In June 2011, WPZ replaced its existing $1.75 billion unsecured revolving credit facility agreement that was scheduled to expire in February 2013 with a new $2 billion five-year senior unsecured revolving credit facility agreement. At September 30, 2011, WPZ is in compliance with the financial covenants associated with this new credit facility agreement. This credit facility is only available to WPZ, Transco and Northwest Pipeline as co-borrowers (see Note 9 of Notes to Consolidated Financial Statements).

In addition to the credit facilities listed above, we have issued letters of credit totaling $89 million as of September 30, 2011 under certain bilateral bank agreements.

WPZ filed a shelf registration statement as a well-known, seasoned issuer in October 2009 that allows it to issue an unlimited amount of registered debt and limited partnership unit securities.

At the parent-company level, we filed a shelf registration statement as a well-known, seasoned issuer in May 2009 that allows us to issue an unlimited amount of registered debt and equity securities.

In June 2011, WPX entered into a new $1.5 billion five-year senior unsecured revolving credit facility agreement that would be effective upon meeting certain conditions. This agreement was amended and became effective on November 1, 2011. Also on November 1, 2011, Exploration & Production terminated its existing unsecured credit agreement which had served to reduce margin requirements and transaction fees related to hedging activities, thus satisfying a condition necessary for effectiveness of the new WPX credit facility. All outstanding hedges under the terminated agreement were transferred to new agreements with various financial institutions that participate in the new credit facility. Neither WPX nor the participating financial institutions are required to provide collateral support related to hedging activities under the new agreements. The new credit facility is only available to WPX. (See Note 9 of Notes to Consolidated Financial Statements.)

Table of Contents

Management s Discussion and Analysis (Continued)

Credit Ratings

Our ability to borrow money is impacted by our credit ratings and the credit ratings of WPZ. The current ratings are as follows:

	WMB	WPZ
Standard and Poor s (1)		
Corporate Credit Rating	BBB-	BBB-
Senior Unsecured Debt Rating	BB+	BBB-
Outlook	Positive	Positive
Moody s Investors Service (2)		
Senior Unsecured Debt Rating	Baa3	Baa3
Outlook	Negative (4)	Under review for possible upgrade
Fitch Ratings (3)		
Senior Unsecured Debt Rating	BBB-	BBB-
Outlook	Rating watch negative (5)	Stable

(1) 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 & 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 & Poor s may modify its ratings with a + or a - sign to show the obligor s relative standing within a major rating category.

(2) 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 the lower end of the category.

(3) 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.

(4) On June 24, 2011, Moody s Investors Service revised to negative from stable.

(5) On June 24, 2011, Fitch Ratings revised to rating watch negative from stable.

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, 2011, we estimate that a downgrade to a rating below investment grade for us or WPZ would require us to post up to $537 million or $65 million, respectively, in additional collateral with third parties.

Sources (Uses) of Cash

	Nine months ended September 30,	
	2011	**2010**
	(Millions)	

Net cash provided (used) by:		
Operating activities	$ 2,352	$ 1,941
Financing activities	(163)	(321)
Investing activities	(1,988)	(2,472)
Increase (decrease) in cash and cash equivalents	$ 201	$ (852)

56

Table of Contents

Management s Discussion and Analysis (Continued)

Operating activities

Our *net cash provided by operating activities* for the nine months ended September 30, 2011 increased $411 million from the same period in 2010 primarily due to improved operating results.

Financing activities

Significant transactions include:

- $375 million received by Transco from the issuance of senior unsecured notes in August 2011;
- $300 million paid to retire Transco s senior unsecured notes that matured in August 2011;
- WPZ refinanced $300 million outstanding under the previous $1.75 billion credit facility via a non-cash transfer of the obligation to the new $2 billion credit facility in June 2011;
- $300 million received in revolver borrowings from WPZ s $1.75 billion unsecured credit facility used for WPZ s acquisition of a 24.5 percent interest in Gulfstream from us in May 2011;
- $150 million paid to retire WPZ s senior unsecured notes that matured in June 2011;
- $430 million received in revolver borrowings from WPZ s $1.75 billion unsecured credit facility primarily used to fund our increased ownership in OPPL, a transaction that closed in September 2010;
- $380 million received from WPZ s September 2010 equity offering used to reduce WPZ s revolver borrowings mentioned above;
- $3.491 billion received by WPZ in February 2010 from the issuance of $3.5 billion of senior unsecured notes related to our restructuring;
- $3 billion of senior unsecured notes retired in February 2010 and $574 million paid in associated premiums utilizing proceeds from the $3.5 billion debt issuance;
- $250 million received from revolver borrowings on WPZ s $1.75 billion unsecured credit facility in February 2010 to repay a term loan.

Investing activities

Significant transactions include:

Capital expenditures totaled $1,833 million and $2,111 million for 2011 and 2010, respectively;

$424 million cash payment for WPZ s September 2010 acquisition of an increased interest in OPPL.

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

We have various other guarantees and commitments which are disclosed in Notes 11 and 12 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 2011.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, NGLs and crude, 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 our proprietary trading activities. We manage the risks associated with these market fluctuations 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 11 of Notes to Consolidated Financial Statements.)

We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios. 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 portfolios. 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 portfolios 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 portfolios 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 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 $1 million at September 30, 2011. The value at risk for contracts held for trading purposes was less than $1 million at September 30, 2011 and December 31, 2010.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from the following activities:

Segment	**Commodity Price Risk Exposure**
Williams Partners	Natural gas purchases
	NGL sales
Exploration & Production	Natural gas purchases and sales
	Crude oil sales
Midstream Canada & Olefins	NGL purchases and sales

The fair value of our nontrading derivatives was a net asset of $322 million at September 30, 2011.

Table of Contents

The value at risk for derivative contracts held for nontrading purposes was $21 million at September 30, 2011, and $24 million at December 31, 2010.

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 $313 million as of September 30, 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 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 the company 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 Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Third-Quarter 2011 Changes in Internal Controls

There have been no changes during the third quarter of 2011 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 Transcontinental Gas Pipe Line Company, LLC (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 March 2008, the Environmental Protection Agency (EPA) proposed a penalty of $370,000 for alleged violations relating to leak detection and repair program delays at our Ignacio gas plant in Colorado and for alleged permit violations at a compressor station. Under a settlement reached with the EPA in September 2011, we agreed to pay $50,000 and undertake enhanced leak detection and repair monitoring at the gas plant.

Table of Contents

In July 2011, the New Mexico Environmental Department proposed a $900,000 settlement for alleged violations of the New Mexico Air Quality Act at five separate facilities that we own or operate. We are discussing settlement with the agency.

On August 26, 2011, we signed an Administrative Complaint and Consent Agreement with the EPA to settle allegations of noncompliance with the Clean Air Act Prevention of Significant Deterioration provisions with respect to the absence of emission permits at various drilling pad locations in the Fort Berthold Indian Reservation in North Dakota. We agreed to pay $228,000 in penalties in connection with this settlement.

In September 2011, the Colorado Department of Public Health and Environment proposed a penalty of $301,000 for alleged violations of the Colorado Clean Water Act related to excavation work being done for our Crawford Trail Pipeline. We are discussing settlement with the agency.

Other

The additional information called for by this item is provided in Note 12 of the 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, 2010, 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:

If our plans to separate our exploration and production business are delayed or not completed, our stock price may decline and our growth potential may not be enhanced.

On October 18, 2011, we announced that our Board of Directors approved a revised plan to pursue separation of our businesses into two stand-alone, publicly traded corporations. The revised plan calls for the complete separation of our exploration and production business via a tax free spin-off of all of our ownership of WPX Energy, Inc. (WPX),a wholly owned subsidiary, to our shareholders by year end 2011. Our original plan was to conduct an initial public offering (IPO) of up to 20 percent of WPX in 2011 and a tax-free spin-off of our remaining interest in WPX to our shareholders in 2012. As previously announced, we revised our plans for an IPO due to unfavorable equity market conditions, but we may still pursue the previously proposed partial IPO of WPX if market conditions were to become favorable. On October 19, 2011, WPX filed an initial registration statement on Form 10 in connection with our planned separation. The completion and timing of the transactions associated with our separation plans are dependent on a number of factors including, but not limited to, the macroeconomic environment, credit markets, equity markets, energy prices, the receipt of a tax opinion from counsel and/or an Internal Revenue Service (IRS) ruling with respect to our revised separation plan, final approvals from our Board of Directors, the satisfaction or waiver by us of certain closing conditions and other customary matters. We may not complete the transactions at all or complete the transactions on the timeline or on the terms that we announced. If the transactions are not completed or delayed, our stock price may decline and our growth potential may not be enhanced.

If completed, our plan to separate our exploration and production business may not achieve its intended results.

If completed, our plan to separate our exploration and production business may not achieve its intended results and could have an adverse effect on us due to a number of factors. For example, following separation, the scope and scale of our business will be significantly reduced, we may not be able to grow as expected, we may incur proportionately higher costs to operate, and we may not be able to fill the positions of key employees who separated with WPX with persons of comparable qualifications and experience. Additionally, we cannot assure you that the combined trading prices of our common stock and WPX common stock after the spin-off, as adjusted for any changes in the combined capitalization of these companies, will be equal to or greater than the trading price of our common stock prior to the spin-off. Until the market has fully evaluated our business without the exploration and production business, the price at which our common stock trades may fluctuate significantly. Furthermore, we may incur a non-cash impairment charge if the carrying value of our exploration and production business exceeds its fair value at the time of spin-off.

If, following the completion of a spin-off of WPX stock to our stockholders, there is a determination that the spin-off is taxable for U.S. federal income tax purposes because the facts, assumptions, representations, or undertakings underlying an IRS private letter ruling or a tax opinion are incorrect or for any other reason, then we and our stockholders could incur significant income tax liabilities.

In connection with our original separation plan that called for an IPO and spin-off, we obtained a private letter ruling from the IRS and an opinion of our outside tax advisor, to the effect that the distribution by us of WPX shares to our stockholders, and any related restructuring transaction undertaken by us, will qualify for U.S. federal income tax purposes as a tax-free transaction under section 355 and section 368(a)(1)(D) of the Code. Our revised separation plan discussed above is also conditioned on our receipt of a private letter ruling from the IRS and/or an opinion from our outside tax advisor that the spin-off pursuant to the revised plan will qualify as a tax-free transaction. These rulings and opinions have relied on or will rely on certain facts, assumptions, representations and undertakings from us and WPX regarding the past and future conduct of the companies respective businesses and other matters. If any of these facts, assumptions, representations, or undertakings are, or become, incorrect or are not otherwise satisfied; we and our stockholders may not be able to rely on the opinion of our tax advisor and/or the private letter ruling and could be subject to significant tax liabilities. In addition, notwithstanding the opinion of our tax advisor, the IRS could conclude upon audit that the spin-off is taxable if it determines that any of these facts, assumptions, representations, or undertakings are, or have become, not correct or have been violated or if it disagrees with the conclusions in the applicable opinion, or for other reasons, including as a result of certain significant changes in the stock ownership of us or WPX after the spin-off. If the spin-off is determined to be taxable for U.S. federal income tax purposes for any reason, we and/or our stockholders could incur significant income tax liabilities.

The spin-off may expose us to potential liabilities arising out of state and federal fraudulent conveyance laws that we did not assume in our agreements with WPX.

The spin-off is subject to review under various state and federal fraudulent conveyance laws. A court could deem the spin-off or certain internal restructuring transactions undertaken by us in connection with the separation to be a fraudulent conveyance or transfer. Fraudulent conveyances or transfers are defined to include transfers made or obligations incurred with the actual intent to hinder, delay or defraud current or future creditors or transfers made or obligations incurred for less than reasonably equivalent value when the debtor was insolvent, or that rendered the debtor insolvent, inadequately capitalized or unable to pay its debts as they become due. A court could void the transactions or impose substantial liabilities upon us, which could adversely affect our financial condition and our results of operations. Whether a transaction is a fraudulent conveyance or transfer will vary depending upon the jurisdiction whose law is being applied. Under the separation and distribution agreement, from and after the spin-off, each of WPX and we will be responsible for the debts, liabilities and other obligations related to the business or businesses which it owns and operates following the consummation of the spin-off. Although we do not expect to be liable for any such obligations not expressly assumed by us pursuant to the separation and distribution agreement, it is possible that a court would disregard the allocation agreed to between the parties, and require that we assume responsibility for obligations allocated to WPX, particularly if WPX were to refuse or were unable to pay or perform the subject allocated obligations.

Our costs of testing, maintaining or repairing our facilities may exceed our expectations and the FERC or competition in our markets may not allow us to recover such costs in the rates we charge for our services.

We could experience unexpected leaks or ruptures on our gas pipeline system, or be required by regulatory authorities to test or undertake modifications to our systems that could result in a material adverse impact on our business, financial condition and results of operations if the costs of testing, maintaining or repairing our facilities exceed current expectations and the FERC or competition in our markets do not allow us to recover such costs in the rates we charge for our service. For example, in response to a recent third-party pipeline rupture, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs. Additionally, failure to locate such records could result in reduction of allowable operating pressures, which would reduce available capacity on our pipelines.

Table of Contents

Item 6. Exhibits

Exhibit 3.1	Restated Certificate of Incorporation (filed on May 26, 2010, as Exhibit 3.1 to the Company s Current Report on Form 8-K) and incorporated herein by reference.
Exhibit 3.2	Restated By-Laws (filed on May 26, 2010, as Exhibit 3.2 to the Company s Current Report on Form 8-K) and incorporated herein by reference.
Exhibit 4.1	Indenture, dated as of August 12, 2011, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on August 12, 2011 as Exhibit 4.1 to Transcontinental Gas Pipe Line Company, LLC s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 12	Computation of Ratio of Earnings to Fixed Charges.(1)
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.(1)
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.(1)
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.(2)
Exhibit 101.INS	XBRL Instance Document.(1)
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.(1)
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.(1)
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.(1)
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.(1)
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.(1)

(1) Filed herewith.
(2) Furnished herewith.

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.

THE WILLIAMS COMPANIES, INC.

(Registrant)

/s/ Ted T. Timmermans
Ted T. Timmermans
Controller (Duly Authorized Officer and Principal Accounting Officer)

November 2, 2011

EXHIBIT INDEX

Exhibit 3.1	Restated Certificate of Incorporation (filed on May 26, 2010, as Exhibit 3.1 to the Company s Current Report on Form 8-K) and incorporated herein by reference.
Exhibit 3.2	Restated By-Laws (filed on May 26, 2010, as Exhibit 3.2 to the Company s Current Report on Form 8-K) and incorporated herein by reference.
Exhibit 4.1	Indenture, dated as of August 12, 2011, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on August 12, 2011 as Exhibit 4.1 to Transcontinental Gas Pipe Line Company, LLC s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 12	Computation of Ratio of Earnings to Fixed Charges.(1)
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.(1)
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.(1)
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.(2)
Exhibit 101.INS	XBRL Instance Document.(1)
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.(1)
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.(1)
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.(1)
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.(1)
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.(1)

(1) Filed herewith.
(2) Furnished herewith.