WILLIAMS COMPANIES INC
Form 10-Q
August 04, 2011

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 June 30, 2011

or

o **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 incorporation or organization)	(I.R.S. Employer 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 o

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 o No

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.) Yes o 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 August 1, 2011
Common Stock, $1 par value	588,895,011 Shares

The Williams Companies, Inc.
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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, intends, might, goals, obj potential, projects, scheduled, will or other similar expressions. These forward-looking statements are based on management s beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

Amounts and nature of future capital expenditures;

Expansion and growth of our business and operations;

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.

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:

- 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.

The Williams Companies, Inc.
Consolidated Statement of Operations
(Unaudited)

(Millions, except per-share amounts)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Revenues:				
Williams Partners	$ 1,671	$ 1,400	$ 3,250	$ 2,890
Exploration & Production	981	901	1,970	2,058
Midstream Canada & Olefins	347	257	663	529
Other	7	5	13	11
Intercompany eliminations	(337)	(274)	(652)	(608)
Total revenues	2,669	2,289	5,244	4,880
Segment costs and expenses:				
Costs and operating expenses	1,938	1,717	3,846	3,634
Selling, general, and administrative expenses	134	123	271	234
Other (income) expense net	3	(12)	2	(13)
Total segment costs and expenses	2,075	1,828	4,119	3,855
General corporate expenses	47	45	98	130
Operating income (loss):				
Williams Partners	435	334	847	732
Exploration & Production	89	68	134	216
Midstream Canada & Olefins	72	61	146	81
Other	(2)	(2)	(2)	(4)
General corporate expenses	(47)	(45)	(98)	(130)
Total operating income (loss)	547	416	1,027	895
Interest accrued	(156)	(154)	(314)	(318)
Interest capitalized	9	13	18	30
Investing income net	45	55	96	94
Early debt retirement costs				(606)
Other income (expense) net		(1)	4	(8)
Income (loss) from continuing operations before income taxes	445	329	831	87
Provision (benefit) for income taxes	145	104	139	10
Income (loss) from continuing operations	300	225	692	77
Income (loss) from discontinued operations	(3)	(3)	(11)	(1)
Net income (loss)	297	222	681	76
Less: Net income attributable to noncontrolling interests	70	37	133	84

Net income (loss) attributable to The Williams Companies, Inc.	$ 227	$ 185	$ 548	$ (8)
Amounts attributable to The Williams Companies, Inc.:				
Income (loss) from continuing operations	$ 230	$ 188	$ 559	$ (7)
Income (loss) from discontinued operations	(3)	(3)	(11)	(1)
Net income (loss)	$ 227	$ 185	$ 548	$ (8)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ .39	$ .32	$ .95	$ (.01)
Income (loss) from discontinued operations			(.02)	
Net income (loss)	$ .39	$ .32	$ .93	$ (.01)
Weighted-average shares (thousands)	588,310	584,414	587,641	584,173
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ .38	$ .31	$ .94	$ (.01)
Income (loss) from discontinued operations			(.02)	
Net income (loss)	$ .38	$ .31	$ .92	$ (.01)
Weighted-average shares (thousands)	597,633	592,498	597,097	584,173
Cash dividends declared per common share	$ .200	$ .125	$ .325	$ .235

See accompanying notes.

The Williams Companies, Inc.
Consolidated Balance Sheet
(Unaudited)

(Dollars in millions, except per-share amounts)	June 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,166	$ 795
Accounts and notes receivable (net of allowance of $17 at June 30, 2011 and $15 at December 31, 2010)	913	859
Inventories	282	302
Derivative assets	263	400
Other current assets and deferred charges	206	174
Total current assets	2,830	2,530
Investments	1,463	1,344
Property, plant, and equipment, at cost	31,442	30,365
Accumulated depreciation, depletion, and amortization	(10,842)	(10,144)
Property, plant, and equipment net	20,600	20,221
Derivative assets	138	173
Other assets and deferred charges	674	704
Total assets	$ 25,705	$ 24,972
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 988	$ 918
Accrued liabilities	915	1,002
Derivative liabilities	104	146
Long-term debt due within one year	383	508
Total current liabilities	2,390	2,574
Long-term debt	8,927	8,600
Deferred income taxes	3,572	3,448
Derivative liabilities	112	143
Other liabilities and deferred income	1,659	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 June 30, 2011 and 620 million shares issued at December 31, 2010)	623	620

Capital in excess of par value	8,351	8,269
Retained earnings (deficit)	(122)	(478)
Accumulated other comprehensive income (loss)	(95)	(82)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders equity	7,716	7,288
Noncontrolling interests in consolidated subsidiaries	1,329	1,331
Total equity	9,045	8,619
Total liabilities and equity	$ 25,705	$ 24,972

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Changes in Equity
(Unaudited)

	Three months ended June 30,					
	2011			2010		
(Millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 7,537	$ 1,342	$ 8,879	$ 7,919	$ 1,043	$ 8,962
Comprehensive income (loss):						
Net income (loss)	227	70	297	185	37	222
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	8		8	(42)	1	(41)
Foreign currency translation adjustments	5		5	(29)		(29)
Pension and other postretirement benefits net	5		5	5		5
Unrealized gain (loss) on equity securities	3		3			
Total other comprehensive income (loss)	21		21	(66)	1	(65)
Total comprehensive income (loss)	248	70	318	119	38	157
Cash dividends common stock	(118)		(118)	(73)		(73)
Dividends and distributions to noncontrolling interests		(53)	(53)		(34)	(34)
Stock-based compensation, net of tax	17		17	13		13
Issuance of common stock from 5.5% debentures conversion	2		2			
Changes in Williams Partners L.P. ownership interest (Note 2)	30	(30)				
Other				1		1
Ending balance	$ 7,716	$ 1,329	$ 9,045	$ 7,979	$ 1,047	$ 9,026

	Six months ended June 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)	548	133	681	(8)	84	76
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	(54)		(54)	105	3	108
Foreign currency translation adjustments	27		27	(10)		(10)
Pension and other postretirement benefits net	11		11	10		10
Unrealized gain (loss) on equity securities	3		3			
Total other comprehensive income (loss)	(13)		(13)	105	3	108
Total comprehensive income (loss)	535	133	668	97	87	184
Cash dividends common stock	(191)		(191)	(137)		(137)
Dividends and distributions to noncontrolling interests		(105)	(105)		(66)	(66)
Stock-based compensation, net of tax	52		52	25		25
Issuance of common stock from 5.5% debentures conversion	2		2			
Changes in Williams Partners L.P. ownership interest (Note 2)	30	(30)		(454)	454	
Other				1		1
Ending balance	$ 7,716	$ 1,329	$ 9,045	$ 7,979	$ 1,047	$ 9,026

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Cash Flows
(Unaudited)

(Millions)	Six months ended June 30, 2011	2010
OPERATING ACTIVITIES:		
Net income (loss)	$ 681	$ 76
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation, depletion, and amortization	784	727
Provision (benefit) for deferred income taxes	87	50
Provision for loss on investments, property and other assets	51	10
Amortization of stock-based awards	25	26
Early debt retirement costs		606
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	(56)	115
Inventories	20	(57)
Margin deposits and customer margin deposits payable	(30)	5
Other current assets and deferred charges	(9)	(6)
Accounts payable	109	(89)
Accrued liabilities	30	(157)
Changes in current and noncurrent derivative assets and liabilities	14	(34)
Other, including changes in noncurrent assets and liabilities	(22)	25
Net cash provided by operating activities	1,684	1,297
FINANCING ACTIVITIES:		
Proceeds from long-term debt	425	3,749
Payments of long-term debt	(225)	(3,515)
Dividends paid	(191)	(137)
Dividends and distributions paid to noncontrolling interests	(105)	(66)
Payments for debt issuance costs	(19)	(66)
Premiums paid on early debt retirements		(574)
Other net	1	(21)
Net cash used by financing activities	(114)	(630)
INVESTING ACTIVITIES:		
Capital expenditures*	(1,094)	(940)
Purchases of investments/advances to affiliates	(132)	(20)
Other net	27	27
Net cash used by investing activities	(1,199)	(933)
Increase (decrease) in cash and cash equivalents	371	(266)
Cash and cash equivalents at beginning of period	795	1,867

Cash and cash equivalents at end of period	$ 1,166	$ 1,601
* Increases to property, plant, and equipment	$ (1,086)	$ (898)
Changes in related accounts payable and accrued liabilities	(8)	(42)
Capital expenditures	$ (1,094)	$ (940)

See accompanying notes.

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 June 30, 2011, results of operations and changes in equity for the three and six months ended June 30, 2011 and 2010, and cash flows for the six months ended June 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.

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. On April 29, 2011, our wholly owned subsidiary, WPX Energy, Inc. (WPX), filed a registration statement with the Securities and Exchange Commission (SEC) with respect to an initial public offering (IPO) of its equity securities and on July 28, 2011, WPX filed the third amendment to its registration statement with the SEC. This is the first step in our reorganization plan, which calls for a separation of our exploration and production business through an IPO and a subsequent tax-free spin-off of our remaining interest in WPX to our shareholders. 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 processing, fractionation, and natural gas liquid (NGL) 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.

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

Notes (Continued)

During second-quarter 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 one percent interest in Gulfstream, reported within 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 $4 million and $7 million for the three months and $12 million and $15 million for the six months ended June 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.

During fourth-quarter 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 June 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.

The change in WPZ ownership between us and the noncontrolling interests as a result of our February 2010 strategic restructuring was accounted for as an equity transaction and resulted in a $454 million decrease to *capital in excess of par value* and a corresponding increase to *noncontrolling interest in consolidated subsidiaries.*

For the first and second quarter of 2010, this amount related to the change between our ownership interest and the noncontrolling interests resulting from the restructuring was originally reported as $800 million. During the third quarter of 2010, we determined that this amount was incorrect. This error resulted in a $346 million overstatement of *noncontrolling interests in consolidated subsidiaries* and a $346 million understatement of *capital in excess of par value* in the first and second quarter. The error did not impact *total equity*, key financial covenants, any earnings or cash flow measures or any other key internal measures. The amounts for the six months ended June 30, 2010 have been adjusted for the correction in the Consolidated Statement of Changes in Equity.

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)

Notes (Continued)

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.

Note 3. Discontinued Operations

Summarized Results of Discontinued Operations

	Three months ended June 30,		**Six months ended June 30,**	
	2011	**2010**	**2011**	**2010**
	(Millions)			
Revenues	$ 4	$ 4	$ 7	$ 9
Income (loss) from discontinued operations before impairments and income taxes	$	$ (2)	$ (2)	$ 2
Impairments	(2)		(11)	
(Provision) benefit for income taxes	(1)	(1)	2	(3)
Income (loss) from discontinued operations	$ (3)	$ (3)	$ (11)	$ (1)

Impairments in 2011 reflect write-downs to an estimate of fair value less costs to sell the assets of our Arkoma basin operations. This nonrecurring fair value measurement, which falls within Level 3 of the fair value hierarchy, was based on a probability-weighted discounted cash flow analysis that included 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 June 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 and Other Accruals

Other (income) expense net within *segment costs and expenses* in 2011 includes $10 million related to the reversal of project feasibility costs from expense to capital at Williams Partners, 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.

Additional Items

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

$606 million of early debt retirement costs consisting primarily of cash premiums;

$41 million of other transaction costs reflected in *general corporate expenses,* of which $5 million is attributable to noncontrolling interests;

Notes (Continued)

$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)*.

Exploration & Production recorded a $14 million unfavorable adjustment to *costs and operating expenses* for the six months ended June 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 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 a $13 million gain in the second quarter of 2010 related to cash received at the closing of this sale. These gains are reflected within *investing income net* at Other. Payments are recognized as income upon receipt until such point future collections are reasonably assured.

Note 5. Provision (Benefit) for Income Taxes

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

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)		(Millions)	
Current:				
Federal	$ 30	$ 70	$ 47	$ (43)
State	2	5	3	(9)
Foreign	16	8	(2)	13
	48	83	48	(39)
Deferred:				
Federal	86	15	78	38
State	7	3	8	6
Foreign	4	3	5	5
	97	21	91	49
Total provision (benefit)	$ 145	$ 104	$ 139	$ 10

The effective income tax rates for the total provision for the three months ended June 30, 2011 and 2010 are less than the federal statutory rate primarily due to the impact of nontaxable noncontrolling interests and taxes on foreign operations, partially offset by the effect of state income taxes.

The effective income tax rate for the total provision for the six months ended June 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 and taxes on foreign operations, partially offset by the effect of state income taxes.

The effective income tax rate for the total provision for the six months ended June 30, 2010 is less than the federal statutory rate primarily due to the impact of nontaxable noncontrolling interests, partially offset by the reduction of tax benefits on the Medicare Part D federal subsidy due to enacted health care legislation.

During the first quarter of 2011, we finalized settlements for 1997 through 2008 on certain contested matters with the Internal Revenue Service (IRS) and also received a revised assessment on an international matter. These settlements and revised assessment resulted in a net tax benefit of approximately $124 million during the first quarter of 2011. As a result of these settlements and revised assessment, we have decreased our unrecognized tax benefits by approximately $62 million. In July 2011, we made an $82 million cash payment with respect to the settlements to the IRS and we anticipate making an additional $85 million to $90 million of cash payments to taxing authorities related to these items in 2011.

Notes (Continued)

During the next twelve months, we do not expect ultimate resolution of any uncertain tax position will result in a significant increase or decrease of our unrecognized tax benefit.

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

	Three months ended June 30,		Six months ended June 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)	$ 230	$ 188	$ 559	$ (7)
Basic weighted-average shares	588,310	584,414	587,641	584,173
Effect of dilutive securities:				
Nonvested restricted stock units	3,887	2,826	4,005	
Stock options	3,537	3,022	3,501	
Convertible debentures	1,899	2,236	1,950	
Diluted weighted-average shares	597,633	592,498	597,097	584,173
Earnings (loss) per common share from continuing operations:				
Basic	$ .39	$ .32	$ .95	$ (.01)
Diluted	$ .38	$ .31	$ .94	$ (.01)

(1) The three- and six-month periods ended June 30, 2011, include $.2 million and $.4 million, respectively, and the three-month period ended June 30, 2010 includes $.2 million 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 six months ended June 30, 2010, 3.0 million weighted-average nonvested restricted stock units and 3.1 million 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 six months ended June 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 $109 million of income for the six months ended June 30, 2010, then these shares would become dilutive.

Notes (Continued)

The table below includes information related to stock options that were outstanding at June 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 second quarter weighted-average market price of our common shares.

	June 30, 2011	June 30, 2010
Options excluded (millions)	1.0	3.3
Weighted-average exercise price of options excluded	$ 36.47	$ 29.44
Exercise price ranges of options excluded	$ 32.05 - $37.88	$ 21.55 - $40.51
Second quarter weighted-average market price	$ 30.54	$ 21.54

In the second quarter of 2011, an additional 600 thousand options with exercise prices less than the second quarter weighted-average market price were excluded from the computation of weighted-average stock options due to the shares being antidilutive.

Note 7. Employee Benefit Plans

Net periodic benefit expense is as follows:

	Pension Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)			
Components of net periodic benefit expense:				
Service cost	$ 10	$ 10	$ 20	$ 18
Interest cost	15	16	32	32
Expected return on plan assets	(19)	(17)	(38)	(35)
Amortization of net actuarial loss	10	8	19	17
Net periodic benefit expense (income)	$ 16	$ 17	$ 33	$ 32

	Other Postretirement Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)			
Components of net periodic benefit expense:				
Service cost	$	$	$ 1	$ 1
Interest cost	3	4	7	8
Expected return on plan assets	(2)	(2)	(5)	(5)
Amortization of prior service cost (credit)	(2)	(4)	(5)	(7)
Amortization of net actuarial loss	1	1	2	1
Amortization of regulatory asset		1		1
Net periodic benefit expense (income)	$	$	$	$ (1)

During the six months ended June 30, 2011, we contributed $33 million to our pension plans and $7 million to our other postretirement benefit plans. During July 2011, we contributed an additional $30 million to our pension plans. We presently anticipate making additional contributions of approximately $5 million to our pension plans and approximately $8 million to our other postretirement benefit plans in the remainder of 2011.

Notes (Continued)

Note 8. Inventories

	June 30, 2011	December 31, 2010
	(Millions)	
Natural gas liquids and olefins	$ 88	$ 87
Natural gas in underground storage	81	93
Materials, supplies, and other	113	122
	$ 282	$ 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 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) must 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 June 30, 2011, we are in compliance with these financial covenants.

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:

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

WPX entered into a new $1.5 billion unsecured revolving credit facility agreement that will be effective upon meeting certain conditions, including the completion of WPX s initial public offering. This credit facility will only be available to WPX. The new agreement will automatically terminate if the effective date has not occurred on or before November 30, 2011. The credit facility may, under certain conditions, be increased up to an additional $300 million and 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;

Notes (Continued)

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

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 agreements in effect) 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 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 at June 30, 2011, are:

	Expiration	Letters of Credit	Loans
		(Millions)	
$900 million unsecured credit facility (1)	June 3, 2016	$	$
$2 billion WPZ unsecured credit facility (2) (3)	June 3, 2016		350
Bilateral bank agreements for letters of credit		74	
		$ 74	$ 350

(1) $700 million letter of credit capacity.

(2) $1.3 billion letter of credit capacity.

(3) Subsequent to June 30, 2011, WPZ repaid a net $100 million of this loan balance.

Retirements

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

Notes (Continued)

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.

	June 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)							
Assets:								
Energy derivatives	$ 46	$ 352	$ 3	$ 401	$ 96	$ 475	$ 2	$ 573
ARO Trust investments (see Note 11)	40			40	40			40
Available-for-sale equity securities (see Note 11)	27			27				
Total assets	$ 113	$ 352	$ 3	$ 468	$ 136	$ 475	$ 2	$ 613
Liabilities:								
Energy derivatives	$ 41	$ 173	$ 2	$ 216	$ 78	$ 210	$ 1	$ 289
Total liabilities	$ 41	$ 173	$ 2	$ 216	$ 78	$ 210	$ 1	$ 289

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 18 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.

Notes (Continued)

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 June 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 June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)			
Beginning balance	$	$ 5	$ 1	$ 2
Realized and unrealized gains (losses):				
Included in income (loss) from continuing operations	3	(1)	2	(1)
Included in other comprehensive income (loss)		11	(1)	15
Settlements	(2)	(1)	(2)	(2)
Transfers into Level 3				
Transfers out of Level 3			1	
Ending balance	$ 1	$ 14	$ 1	$ 14
Unrealized gains (losses) included in income (loss) from continuing operations relating to instruments still held at June 30	$ 1	$ (1)	$	$ (1)

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.

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. Private debt is valued based on market rates and the prices of similar securities with similar terms and credit ratings. At June 30, 2011 and December 31, 2010, approximately 96 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

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Notes (Continued)
WilTel s current owner and the term of the underlying obligation. The default rates are published by Moody s Investors Service. Guarantees, if recognized, are 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

	June 30, 2011		December 31, 2010	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
		(Millions)		
Cash and cash equivalents	$ 1,166	$ 1,166	$ 795	$ 795
Restricted cash (current and noncurrent)	$ 29	$ 29	$ 28	$ 28
ARO Trust investments	$ 40	$ 40	$ 40	$ 40
Long-term debt, including current portion (a)	$(9,305)	$(10,325)	$(9,104)	$(9,990)
Guarantees	$ (34)	$ (32)	$ (35)	$ (34)
Other	$ 42	$ 41(b)	$ (23)	$ (25)(b)
Net energy derivatives:				
Energy commodity cash flow hedges	$ 182	$ 182	$ 266	$ 266
Other energy derivatives	$ 3	$ 3	$ 18	$ 18

(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 June 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. 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:

- 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).

Notes (Continued)

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of June 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	(258,680,000)	(258,680,000)		(50,600,000)
Exploration & Production	Risk Management	Barrels	(3,405,500)			
Williams Partners	Risk Management	MMBtu	10,735,000	9,355,000		
Williams Partners	Risk Management	Barrels	(2,960,000)			
Not Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(12,940,000)	(15,965,000)	(46,487,263)	
Williams Partners	Risk Management	Barrels	(54,000)			
Midstream Canada & Olefins	Risk Management	Barrels	(50,000)		(144,300)	
Exploration & Production	Other	MMBtu		(8,007,500)		

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.

	June 30, 2011		**December 31, 2010**	
	Assets	**Liabilities**	**Assets**	**Liabilities**
	(Millions)			
Designated as hedging instruments	$ 209	$ 27	$ 288	$ 22
Not designated as hedging instruments:				
Legacy natural gas contracts from former power business	174	173	186	187
All other	18	16	99	80

Total derivatives not designated as hedging instruments	192	189	285	267
Total derivatives	$ 401	$ 216	$ 573	$ 289

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 June 30,		**Six months ended June 30,**		
	2011	**2010**	**2011**	**2010**	**Classification**
	(Millions)		**(Millions)**		
Net gain (loss) recognized in other comprehensive income (loss) (effective portion)	$ 75	$ 32	$ 52	$ 310	AOCI
Net gain (loss) reclassified from accumulated other income (effective portion)	$ 63	$ 100	$ 138	$ 125	Revenues or Costs and Operating Expenses
Gain (loss) recognized in income (ineffective portion)	$	$ (2)	$	$ 3	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 June 30,		**Six months ended June 30,**	
	2011	**2010**	**2011**	**2010**
	(Millions)		**(Millions)**	
Revenues	$ 2	$ (15)	$ 4	$ 11
Costs and operating expenses		7		7
Net gain (loss)	$ 2	$ (22)	$ 4	$ 4

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. Additionally, Exploration & Production has an unsecured credit agreement with certain banks related to hedging activities. We are 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, exceeds 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.

As of June 30, 2011, we did not have any collateral 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 reduction of significantly 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

Notes (Continued)

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 $22 million and $29 million at June 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 June 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 June 30, 2011, $97 million of net gains (net of income tax provision of $58 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of June 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 June 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 June 30, 2011 and $35 million at December 31, 2010.

At June 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 June 30, 2011, is summarized as follows:

Notes (Continued)

Counterparty Type	**Investment Grade(a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 3	$ 3
Energy marketers and traders		112
Financial institutions	286	286
	$ 289	401
Credit reserves		
Gross credit exposure from derivatives		$ 401

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 June 30, 2011, excluding collateral support discussed below, is summarized as follows:

Notes (Continued)

Counterparty Type	**Investment Grade(a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 2	$ 2
Energy marketers and traders		1
Financial institutions	204	204
	$ 206	207
Credit reserves		
Net credit exposure from derivatives		$ 207

(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.

Our ten 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 86 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.

At June 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 $4 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 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

Notes (Continued)

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

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 U.S. Environmental Protection Agency (EPA), various state environmental authorities and identification as a potentially responsible party at various Superfund waste disposal sites. At June 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 June 30, 2011, we have accrued liabilities totaling $8 million for these costs.

In March 2008, the 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. Tentative settlement was reached in first-quarter 2011.

In September 2007, the EPA requested, and our Transco subsidiary later provided, information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA s investigation of our 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 our response denying the allegations in June 2008. In May 2011, we 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 our Transco subsidiary provided, similar information for a compressor station in Maryland.

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;

Discontinued petroleum refining facilities;

Former exploration and production and mining operations.

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

Notes (Continued)

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. Any incremental amount cannot be reasonably estimated at this time.

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.

Environmental matters general

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.

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.

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

Notes (Continued)
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.

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

Notes (Continued)

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 June 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

Litigation, arbitration, regulatory matters, and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a material adverse effect upon our future liquidity or financial position.

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.

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	Other	Eliminations	Total
			(Millions)			
Three months ended June 30, 2011						
Segment revenues:						
External	$ 1,557	$ 762	$ 345	$ 5	$	$ 2,669
Internal	114	219	2	2	(337)	
Total revenues	$ 1,671	$ 981	$ 347	$ 7	$ (337)	$ 2,669
Segment profit (loss)	$ 471	$ 94	$ 72	$ 2	$	$ 639
Less equity earnings (losses)	36	5		4		45
Segment operating income (loss)	$ 435	$ 89	$ 72	$ (2)	$	594
General corporate expenses						(47)
Total operating income (loss)						$ 547
Three months ended June 30, 2010						
Segment revenues:						
External	$ 1,307	$ 726	$ 254	$ 2	$	$ 2,289
Internal	93	175	3	3	(274)	
Total revenues	$ 1,400	$ 901	$ 257	$ 5	$ (274)	$ 2,289
Segment profit (loss)	$ 361	$ 73	$ 61	$ 18	$	$ 513
Less:						
Equity earnings (losses)	27	5		7		39
Income (loss) from investments				13		13
Segment operating income (loss)	$ 334	$ 68	$ 61	$ (2)	$	461

General corporate expenses												(45)
Total operating income (loss)											$	416
Six months ended June 30, 2011												
Segment revenues:												
External	$	3,035	$	1,541	$	661	$	7	$		$	5,244
Internal		215		429		2		6		(652)		
Total revenues	$	3,250	$	1,970	$	663	$	13	$	(652)	$	5,244
Segment profit (loss)	$	908	$	145	$	146	$	22	$		$	1,221
Less:												
Equity earnings (losses)		61		11				13				85
Income (loss) from investments								11				11
Segment operating income (loss)	$	847	$	134	$	146	$	(2)	$			1,125
General corporate expenses												(98)
Total operating income (loss)											$	1,027
Six months ended June 30, 2010												
Segment revenues:												
External	$	2,704	$	1,651	$	521	$	4	$		$	4,880
Internal		186		407		8		7		(608)		
Total revenues	$	2,890	$	2,058	$	529	$	11	$	(608)	$	4,880
Segment profit (loss)	$	785	$	226	$	81	$	25	$		$	1,117
Less:												
Equity earnings (losses)		53		10				16				79
Income (loss) from investments								13				13
Segment operating income (loss)	$	732	$	216	$	81	$	(4)	$			1,025
General corporate expenses												(130)

Total operating income (loss)						$ 895
June 30, 2011						
Total assets (a)	$ 13,723	$ 9,778	$ 1,052	$ 1,478	$ (326)	$ 25,705
December 31, 2010						
Total assets	$ 13,404	$ 9,827	$ 922	$ 3,481	$ (2,662)	$ 24,972

(a) The decrease in Other and Eliminations is substantially due to the forgiveness of an intercompany long-term receivable.

Notes (Continued)

Total segment revenues for Exploration & Production include gas management revenues of $337 million and $365 million for the three months ended June 30, 2011 and 2010, respectively, and $742 million and $921 million for the six months ended June 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.

Item 2
Management s Discussion and Analysis of
Financial Condition and Results of Operations

Changes in Structure and Dividend Increase

On February 16, 2011, we announced our reorganization plan to divide our business into two separate, publicly traded corporations. On April 29, 2011, our wholly owned subsidiary, WPX Energy, Inc. (WPX), filed a registration statement with the SEC with respect to an initial public offering (IPO) of its equity securities and on July 28, 2011, WPX filed the third amendment to its registration statement with the SEC. This is the first step in our reorganization plan, which calls for a separation of our exploration and production business through an IPO of up to 20 percent of WPX in 2011 and a subsequent tax-free spin-off of our remaining interest in WPX to our shareholders in 2012, after which Williams would continue as a natural gas infrastructure company. 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 will become effective upon the completion of specified conditions, including completion of the IPO (See Note 9 of Notes to Consolidated Financial Statements). We expect that WPX will also issue senior unsecured notes in conjunction with the IPO. Our plan is to use a substantial portion of the combined net proceeds of the debt offering and IPO to repay a portion of our existing debt, along with any associated premiums.

Additionally, 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.

Overview of Six Months Ended June 30, 2011

Income (loss) from continuing operations attributable to The Williams Companies, Inc., for the six months ended June 30, 2011, changed favorably by $566 million compared to the six months ended June 30, 2010. This change includes:

- The absence of $645 million of pre-tax costs attributable to The Williams Companies, Inc., associated with our 2010 restructuring, including $606 million of early debt retirement costs.

- A $124 million net tax benefit recorded in first-quarter 2011 associated with federal settlements and an international revised assessment. (See Note 5 of Notes to Consolidated Financial Statements.)

- A $115 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 $65 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).

Partially offsetting these favorable changes are lower operating results within Exploration & Production. (See Results of Operations Segments, Exploration & Production.)

See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for the six months ended June 30, 2011, increased $387 million compared to the six months ended June 30, 2010, primarily due to improved operating results and net favorable changes in working capital. *(*See Management s Discussion and Analysis of Financial Condition and Liquidity.)

Management s Discussion and Analysis (Continued)

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 May 2011, we announced that Williams Partners was chosen by an operator 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 60,000 barrels of oil per day, up to 200 million cubic feet of natural gas per day, 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 coverage, we also purchased named windstorm coverage from OIL. The named windstorm insurance provides coverage up to $150 million per occurrence (60 percent of $250 million of losses in excess of our $100 million deductible), with an annual aggregate limit of $300 million and subject to an aggregate per-event shared limit of $750 million for all members.

Company Outlook

We believe we are well positioned 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.

Economic and commodity price indicators for 2011 and beyond reflect continued improvement in the economic environment. However, given the potential volatility of these measures, the economy could worsen and/or commodity prices could decline, negatively impacting future operating results and increasing the risk of nonperformance of counterparties or impairments of 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.

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.

Management s Discussion and Analysis (Continued)

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.

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 six months ended June 30, 2011, compared to the three and six months ended June 30, 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended June 30, 2011	Three months ended June 30, 2010	$ Change*	% Change*	Six months ended June 30, 2011	Six months ended June 30, 2010	$ Change*	% Change*
	(Millions)				(Millions)			
Revenues	$ 2,669	$ 2,289	+380	+17%	$ 5,244	$ 4,880	+364	+7%
Costs and expenses:								
Costs and operating expenses	1,938	1,717	-221	-13%	3,846	3,634	-212	-6%
Selling, general and administrative expenses	134	123	-11	-9%	271	234	-37	-16%
Other (income) expense net	3	(12)	-15	NM	2	(13)	-15	NM
General corporate expenses	47	45	-2	-4%	98	130	+32	+25%
Total costs and expenses	2,122	1,873			4,217	3,985		
Operating income (loss)	547	416			1,027	895		
Interest accrued net	(147)	(141)	-6	-4%	(296)	(288)	-8	-3%
Investing income net	45	55	-10	-18%	96	94	+2	+2%
Early debt retirement costs						(606)	+606	+100%
Other income (expense) net		(1)	+1	+100%	4	(8)	+12	NM
Income (loss) from continuing operations before income taxes	445	329			831	87		
Provision (benefit) for income taxes	145	104	-41	-39%	139	10	-129	NM
Income (loss) from continuing operations	300	225			692	77		
Income (loss) from discontinued operations	(3)	(3)			(11)	(1)	-10	NM
Net income (loss)	297	222			681	76		
Less: Net income attributable to noncontrolling interests	70	37	-33	-89%	133	84	-49	-58%
	$ 227	$ 185			$ 548	$ (8)		

Net income (loss) attributable to The Williams Companies, Inc.

* + = 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 June 30, 2011 vs. three months ended June 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, partially offset by lower marketing volumes. Additionally, Exploration & Production natural gas production revenues increased reflecting higher average natural gas prices and an increase in production volumes sold. Midstream Canada & Olefins ethylene and propylene production revenues increased primarily due to higher average energy commodity prices.

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, partially offset by lower marketing volumes. In addition, ethylene and propylene feedstock costs increased at Midstream Canada & Olefins reflecting higher per-unit feedstock costs. Gathering, processing, and transportation expenses, as well as depreciation, depletion and amortization expenses, increased at Exploration & Production.

Management s Discussion and Analysis (Continued)

Other (income) expense net within *operating income* in 2010 includes $11 million of involuntary conversion gains at Williams Partners due to insurance recoveries that are in excess of the carrying value of assets.

The favorable change in *operating income (loss)* generally reflects an improved energy commodity price environment in 2011 compared to 2010, partially offset by higher operating costs.

The unfavorable change in *investing income net* is primarily due to the absence of a $13 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 higher pre-tax income in 2011 compared to 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 June 30, 2011 compared to 84 percent at June 30, 2010, and higher operating results, primarily at WPZ, due to an improved energy commodity price environment in 2011 compared to 2010.

Six months ended June 30, 2011 vs. six months ended June 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 and higher NGL marketing volumes, partially offset by a decrease in equity NGL production volumes. Additionally, Midstream Canada & Olefins ethylene and propylene production revenues increased primarily due to higher average energy commodity prices. Exploration & Production natural gas production revenues increased primarily due to higher volumes sold. These increases were partially offset by a decrease in Exploration & Production gas management revenues, reflecting a decrease in 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. The higher marketing purchases are due to higher average commodity prices and higher NGL marketing volumes, and are partially offset by decreased costs associated with the production of NGLs reflecting lower average natural gas prices and lower equity NGL volumes. Additionally, ethylene and propylene feedstock costs increased at Midstream Canada & Olefins reflecting higher per-unit feedstock costs. Exploration & Production incurred higher gathering, processing, and transportation expenses, as well as depreciation, depletion and amortization expenses. These increases were partially offset by decreased 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 $22 million increase at Exploration & Production related to higher bad debt expense, and higher wages, salary and benefits costs as a result of an increase in the number of employees and a $15 million increase at Williams Partners including higher employee-related expenses from gas pipeline operations.

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 $11 million of involuntary conversion gains at Williams Partners, as previously discussed.

General corporate expenses in 2010 includes $41 million of transaction costs associated with our strategic restructuring transaction.

The favorable change in *operating income (loss)* generally reflects 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, primarily at Exploration & Production.

Management s Discussion and Analysis (Continued)

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.

Provision (benefit) for income taxes changed unfavorably primarily due to higher pre-tax income in 2011 compared to 2010, partially offset by an approximate $124 million net tax benefit from federal settlements and an international revised assessment. 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.

See Note 3 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations*.

The unfavorable change in *net income attributable to noncontrolling interests* reflects our decreased percentage of ownership of WPZ, which was 75 percent at June 30, 2011 compared to 84 percent at June 30, 2010, and higher operating results, primarily at WPZ, due to an improved energy commodity price environment in 2011 compared to 2010.

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 June 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 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 Six Months Ended June 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.

Perdido Norte

Both oil and gas production began to flow on a sustained basis during the fourth quarter of 2010 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 production volumes are currently significantly lower than expected, producers continue to work through technical issues, volumes have increased each quarter, and we anticipate volumes to increase significantly during the remainder of 2011.

Overland Pass Pipeline

We became operator of Overland Pass Pipeline Company LLC (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.

Management s Discussion and Analysis (Continued)

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 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 has been revised in the second quarter of 2011, such that we will ultimately provide capacity on the Springville pipeline of approximately 650 MMcf/d.

Gulfstar FPS Deepwater Project

We received a Letter of Award from a significant producer to provide production handling services in the Tubular Bells field development 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 60,000 barrels of oil per day, 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.

Volatile commodity prices

Average per-unit NGL margins in the six months ending June 30, 2011 are significantly higher than the same period in 2010, benefiting from a strong demand for NGLs resulting in higher NGL prices and 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.

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 $129 million.

Management s Discussion and Analysis (Continued)

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.

The operator of the third-party fractionator serving our NGL production transported on Overland Pass Pipeline has notified us of an expected 8- to 10-day outage in the third quarter of 2011 to accommodate their expansion efforts. The outage could result in disruptions and price impacts to our production; however we are evaluating methods to mitigate the impact.

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 $1,270 million to $1,550 million in 2011 on capital projects and additional investments in partially owned equity investments, of which $821 million to $1,101 million remains to be spent. The ongoing major expansion projects include:

<u>85 North</u>

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 in service in May 2011 and increased capacity by 219 Mdt/d.

<u>Mobile Bay South II</u>

Additional compression 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 U.S. Federal Energy Regulatory Commission. Construction began in October 2010 and is estimated to cost $33 million. This project was placed in service in May 2011 and increased capacity by 380 Mdt/d.

<u>Mid-South</u>

Additional compressor facilities and expansion of 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.

Management s Discussion and Analysis (Continued)

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 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. In conjunction with a long-term agreement with a significant producer, we plan to construct and operate a 33-mile, 24-inch diameter natural gas gathering pipeline in the Marcellus Shale region which will connect our recently acquired gathering assets in Pennsylvania s Marcellus Shale into the Transco pipeline. Construction activities on the Springville pipeline and compressor station have begun and the first phase of that project, which will initially allow us to deliver approximately 250 MMcf/d to Transco, is expected to be completed in the latter part of 2011. Expansions to the Springville compression facilities in 2012 will eventually increase the capacity to approximately 650 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 by the end of the fourth quarter of 2011. 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.

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.

Management s Discussion and Analysis (Continued)

Period-Over-Period Operating Results

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)		(Millions)	
Segment revenues	$ 1,671	$ 1,400	$ 3,250	$ 2,890
Segment profit	$ 471	$ 361	$ 908	$ 785

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

The increase in *segment revenues* includes:

A $132 million increase in marketing revenues primarily due to higher average NGL and crude prices, partially offset by lower volumes. These changes are substantially offset by similar changes in marketing purchases.

An $88 million increase in revenues associated with the production of our equity NGLs reflecting an increase of $87 million associated with a 30 percent increase in average NGL per-unit prices.

A $22 million increase in fee revenues primarily due to higher gathering and processing fee revenues including new gathering fee revenues from our gathering assets in the Marcellus Shale in northeastern Pennsylvania acquired in late 2010, higher fees in the Piceance basin as a result of an agreement with Exploration & Production executed in November 2010, 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.

A $16 million increase in natural gas transportation revenue associated with gas pipeline expansion projects placed into service in 2010.

A $14 million increase in revenues from higher transportation imbalance settlements in 2011 compared to 2010. These are offset in *cost and operating expenses*.

Segment costs and expenses increased $170 million, including:

A $116 million increase in marketing purchases primarily due to higher average NGL and crude prices, partially offset by lower volumes. These changes are offset by similar changes in marketing revenues.

A $26 million increase in operating costs reflecting $17 million higher maintenance expenses including higher property insurance expenses and maintenance expenses for our gathering assets in northeastern Pennsylvania acquired at the end of 2010. In addition, depreciation expense is $14 million higher primarily due to new assets placed into service in late 2010.

A $14 million increase in costs from higher transportation imbalance settlements in 2011 compared to 2010. These are offset in *segment revenues*.

An $11 million unfavorable change related to involuntary conversion gains recognized in 2010 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.

The increase in *segment profit* includes:

An $87 million increase in NGL margins reflecting increased average NGL per-unit prices.

A $38 million increase in fee revenues for gathering, processing, and transportation as previously discussed.

Management s Discussion and Analysis (Continued)

A $16 million increase in margins related to the marketing of NGLs and crude.

A $26 million increase in operating costs as previously discussed.

An $11 million unfavorable change related to involuntary conversion gains recognized in 2010 as previously discussed.

Six months ended June 30, 2011 vs. six months ended June 30, 2010

The increase in *segment revenues* includes:

A $235 million increase in marketing revenues primarily due to higher average NGL and crude prices and higher NGL volumes, partially offset by lower crude volumes. These changes are substantially offset by similar changes in marketing purchases.

A $56 million increase in revenues from the production of our equity NGLs reflecting an increase of $91 million associated with a 16 percent increase in average NGL per-unit sales prices, partially offset by a decrease of $35 million associated with a 6 percent decrease in equity NGL volumes.

A $34 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 have higher 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 $23 million increase in natural gas transportation revenue associated with gas pipeline expansion projects placed into service in 2010.

A $17 million increase in revenues from higher transportation imbalance settlements in 2011 compared to 2010. These are offset in *cost and operating expenses*.

Segment costs and expenses increased $245 million, including:

A $206 million increase in marketing purchases primarily due to higher average NGL and crude prices and higher NGL volumes, partially offset by lower crude volumes. These changes are offset by similar changes in marketing revenues.

A $54 million increase in operating costs reflecting $28 million higher maintenance expenses, including higher property insurance expense and maintenance expenses for our gathering assets in northeastern Pennsylvania acquired at the end of 2010. In addition, depreciation expense is $24 million higher primarily due to new assets placed into service in late 2010.

A $17 million increase in costs from higher transportation imbalance settlements in 2011 compared to 2010. These are offset in *segment revenues*.

An $11 million unfavorable change related to involuntary conversion gains recognized in 2010 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.

A $45 million decrease in costs associated with the production of our equity NGLs reflecting a decrease of $27 million associated with a 12 percent decrease in average natural gas prices and a

$17 million decrease reflecting lower equity NGL volumes.

- A $10 million 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 $100 million increase in NGL margins reflecting favorable commodity price changes.
- A $57 million increase in fee revenues for gathering, processing, and transportation as previously discussed.
- A $29 million increase in margins related to the marketing of NGLs and crude.
- A $10 million reversal of project feasibility costs from expense to capital as previously discussed.
- A $54 million increase in operating costs as previously discussed.
- An $11 million unfavorable change related to involuntary conversion gains recognized in 2010 as previously discussed.

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.

As previously disclosed, WPX filed its initial registration statement with the Securities and Exchange Commission on April 29, 2011 and the third amendment on July 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 Six Months Ended June 30, 2011

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

Management s Discussion and Analysis (Continued)

	For the six months ended June 30,		
	2011	**2010**	**% Change**
Average daily domestic production (MMcfe)	1,179	1,095	+8%
Average daily total production (MMcfe)	1,235	1,151	+7%
Domestic production realized average price ($/Mcfe)(1)	$ 5.46	$ 5.41	+1%
Capital expenditures and acquisitions ($ millions)	$ 666	$ 550	+21%
Domestic production revenues ($ millions)	$1,165	$1,073	+9%
Segment revenues ($ millions)	$1,970	$2,058	-4%
Segment profit ($ millions)	$ 145	$ 226	-36%

(1) Realized average prices include market prices, net of fuel and shrink and hedge gains and losses. The realized hedge gain per Mcfe was $0.66 and $0.64 for the first six 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.

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 $1.3 billion and $1.6 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 be for development drilling in the Piceance basin. We also expect annual average daily total production to increase approximately 9 percent over 2010.

During late 2010 and 2011, we incurred approximately $8 million of exploratory drilling costs in connection with a well in the Marcellus Shale area of Columbia County, Pennsylvania. Initial results have been inconclusive and we are continuing to assess the reserves and the economic and operating viability of this well. If upon completion of additional testing, we determine that economic reserves are not present, these capitalized costs will be expensed as exploratory dry hole costs. In addition, if such determination were made, we would assess the impact of that decision on our ability to recover the remaining lease acquisition costs associated with this acreage in Columbia County. Such assessment would include our plans to continue drilling in this area. If a determination is made to not continue development in the approximately 7,900 acres associated with this area, we could incur a potential impairment of these costs of up to $40 million.

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.

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:

Management s Discussion and Analysis (Continued)

	Remainder of 2011 Natural Gas Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars
Natural Gas		
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	385	$5.22

	Remainder of 2011 Crude Oil Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Crude Oil		
WTI Crude Oil fixed-price	4,247	$ 96.31

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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 six months ended June 30, 2011 and 2010:

		Three months ended June 30,		
	2011		2010	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars
Natural Gas				
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	$4.39
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Crude Oil				
WTI Crude Oil fixed-price	3,250	$95.20		

		Six months ended June 30,		
	2011		2010	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars
Natural Gas				
Collar agreements Rockies	45	$5.30 - $7.10	100	$6.53 - $8.94
Collar agreements San Juan	90	$5.27 - $7.06	235	$5.74 - $7.81
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	25	$5.61 - $6.85
NYMEX and basis fixed-price	360	$5.22	120	$4.41
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Crude Oil				
WTI Crude Oil fixed-price	2,367	$95.09		

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 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.

Management s Discussion and Analysis (Continued)
Period-Over-Period Operating Results

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
	(Millions)		(Millions)	
Segment revenues:				
Domestic production revenues	$ 611	$ 507	$ 1,165	$ 1,073
Gas management revenues	337	365	742	921
Hedge ineffectiveness and mark-to-market gains and losses	5		8	9
Other revenues	28	29	55	55
Total segment revenues	$ 981	$ 901	$ 1,970	$ 2,058
Segment profit	$ 94	$ 73	$ 145	$ 226

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

The increase in total *segment revenues* is primarily due to the following:

The $104 million increase in domestic production revenues reflects an increase of $56 million associated with a 10 percent increase in realized average prices (on an Mcfe basis) including the effect of hedges, and an increase of $48 million associated with a 9 percent increase in production volumes sold. Excluding the impact of hedges, production revenues would have increased $136 million from the second quarter of 2010 to the second quarter of 2011. Production revenues in the second quarters of 2011 and 2010 include approximately $112 million and $66 million, respectively, related to natural gas liquids and approximately $65 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 a decrease primarily due to the following:

The $28 million decrease in gas management revenues is primarily due to a decrease in physical natural gas revenue as a result of an 11 percent decrease in natural gas sales volumes, partially offset by a 4 percent increase in average prices on physical natural gas sales. This is primarily related to gas sales associated with our transportation and storage contracts and is significantly offset by a similar decrease in *segment costs and expenses*.

Total *segment costs and expenses* increased $59 million, primarily due to the following:

$33 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;

$24 million higher depreciation, depletion and amortization expenses primarily due to higher production volumes;

$10 million higher operating taxes primarily due to higher production volumes and higher average market prices, excluding the impact of hedges;

$10 million higher lease and other operating expenses primarily due to increased workover, water management and maintenance activity;

$11 million higher exploration expense primarily due to higher amortization and write-off of lease acquisition costs. The increase reflects amortization of leasehold acquisition costs associated with the 2010 acquisitions of leaseholds and $5 million related to leases in the Barnett Shale that we now believe are likely to expire in 2011 without further development;

Management s Discussion and Analysis (Continued)

$8 million higher SG&A due primarily to higher wages, salary and benefits costs as a result of an increase in the number of employees.

Partially offsetting the increases is a decrease primarily due to the following:

$36 million decrease in gas management expenses primarily due to an 11 percent decrease in natural gas purchase volumes, partially offset by a 3 percent increase 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 $8 million and $12 million, respectively, related to charges for unutilized pipeline capacity.

The $21 million increase in *segment profit* is primarily due to higher oil and gas prices and higher production volumes, partially offset by the previously discussed increases in *segment costs and expenses.*

Six months ended June 30, 2011 vs. six months ended June 30, 2010

The decrease in total *segment revenues* is primarily due to the following:

The $179 million decrease in gas management revenues is primarily due to a decrease in physical natural gas revenue as a result of a 10 percent decrease in natural gas sales volumes and an 11 percent decrease in average prices on physical natural gas sales. This is primarily related to gas sales associated with our transportation and storage contracts and is significantly offset by a similar decrease in *segment costs and expenses*.

Partially offsetting the decrease is an increase primarily due to the following:

The $92 million increase in domestic production revenues reflects an increase of $82 million associated with an 8 percent increase in production volumes sold, and an increase of $10 million associated with a 1 percent increase in realized average prices (on an Mcfe basis) including the effect of hedges. Production revenues in 2011 and 2010 include approximately $209 million and $136 million, respectively, related to natural gas liquids and approximately $100 million and $25 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 $6 million primarily due to the following:

$177 million decrease in gas management expenses primarily due to a 10 percent decrease in natural gas purchase volumes and a 10 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 $18 million and $25 million, respectively, related to charges for unutilized pipeline capacity.

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

$56 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

Management s Discussion and Analysis (Continued)

contracts in the Powder River basin;

$33 million higher depreciation, depletion and amortization expenses primarily due to higher production volumes;

$28 million higher exploratory expense in 2011 due to amortization and write-off of lease acquisition costs. The increase reflects amortization of leasehold acquisition costs associated with the 2010 acquisitions of leaseholds and $12 million related to leases in the Barnett Shale that we now believe are likely to expire in 2011 without further development;

$24 million higher lease and other operating expenses primarily due to increased workover, water management and maintenance activity;

$22 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 decreased by $81 million primarily due to the previously discussed decrease in *segment revenues* partially offset by the previously discussed changes 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 olefin by-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 Six Months Ended June 30, 2011

Segment profit for the six months ended June 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, and on Geismar ethylene, 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 be at or above our 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 $350 million to $450 million in 2011 on capital projects, of which $256 million to $356 million remains to be spent. The major expansion projects include:

Management s Discussion and Analysis (Continued)

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. We have begun pre-construction activities and expect to complete the expansions and begin producing ethane/ethylene mix in the first quarter of 2013.

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 2012.

Period-Over-Period Operating Results

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)		(Millions)	
Segment revenues	$ 347	$ 257	$ 663	$ 529
Segment profit	$ 72	$ 61	$ 146	$ 81

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

Segment revenues increased primarily due to:

$33 million higher ethylene production sales revenues primarily due to 35 percent 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.

$17 million higher propylene production revenues due to $28 million higher revenues from 42 percent higher average per-unit sales prices, partially offset by $11 million lower revenues primarily resulting from lower volumes in our Louisiana refinery grade propylene splitter and our Canadian facilities. The 20 percent lower Louisiana propylene splitter sales volumes were primarily due to third-party storage, marketing and supply constraints, partially offset by decreasing inventory levels; however, the impact of the lower sales volumes was substantially offset by similar changes in related costs. The 14 percent decrease in Canadian volumes was primarily due to the reduction in 2011 volumes from planned maintenance at a third-party facility that provides off-gas feedstock to our plant and operational issues at our Fort McMurray plant, partially offset by the impact of 2010 maintenance issues at our Fort McMurray plant.

$11 million higher Canadian NGL production revenues associated with our B/B mix products. 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. Total B/B mix product volumes increased 7 percent, but both periods were negatively impacted by the maintenance issues discussed previously.

Segment costs and expenses increased $79 million primarily as a result of:

$52 million higher ethylene and propylene feedstock costs from higher average per-unit feedstock costs.

$19 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.

Management s Discussion and Analysis (Continued)

Segment profit increased primarily due to $10 million higher Canadian NGL production margins from the B/B mix products, as a result of the B/B splitter.

Six months ended June 30, 2011 vs. six months ended June 30, 2010

Segment revenues increased primarily due to:

$40 million higher ethylene production sales revenues primarily due to 17 percent higher average per-unit sales prices on slightly higher volumes.

$23 million higher propylene production revenues primarily due to $41 million higher revenues from 30 percent higher average per-unit sales prices and $7 million from increased Canadian propylene production sales volumes, partially offset by $27 million lower revenues from decreased propylene production sales volumes at our Louisiana refinery grade propylene splitter. The 23 percent increase in Canadian propylene sales volumes was primarily due to the absence of first-quarter 2010 operational issues at a third-party facility that provides our off-gas feedstock and the absence of second-quarter 2010 maintenance issues at our Fort McMurray plant, partially offset by the second-quarter 2011 planned maintenance and operational issues noted previously. The 25 percent decrease in the Louisiana propylene splitter sales volumes was due to second-quarter 2011 issues noted above and first-quarter 2011 customer outages; however, the impact of the lower sales volumes was substantially offset by similar changes in related costs.

$25 million higher Canadian NGL production revenues associated with our B/B mix products. Total B/B mix product volumes increased 32 percent, but both periods were negatively impacted by maintenance and operational issues discussed previously.

$15 million higher propane production revenues primarily due to 21 percent higher average per-unit prices on 21 percent higher volumes in Canada. The higher Canadian volumes were primarily due to the absence of the 2010 third-party operational issues and Fort McMurray maintenance issues noted above, partially offset by the volume reductions from the previously noted second-quarter 2011 planned maintenance and operational issues.

$15 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 $69 million primarily as a result of:

$41 million higher ethylene and propylene feedstock costs from higher average per-unit feedstock costs.

$11 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.

A $7 million unfavorable change in foreign exchange gains and losses related to the revaluation of current assets held in U.S. dollars within our Canadian operations.

Segment profit increased primarily due to:

$22 million higher Canadian NGL production margins from the B/B mix products, as a result of the B/B splitter.

$18 million higher Geismar ethylene production margins primarily due to 31 percent higher per-unit margins on slightly higher sales volumes.

$14 million higher Canadian propane margins due to 45 percent higher per-unit margins and 21 percent higher volumes.

$14 million higher Canadian propylene margins resulting from 32 percent higher per-unit margins and 23 percent higher volumes.

Management s Discussion and Analysis (Continued)

These increases were partially offset by a $7 million unfavorable change in foreign exchange gains and losses related to the revaluation of current assets held in U.S. dollars within our Canadian operations.

Other

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

Period-Over-Period Operating Results

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)		(Millions)	
Segment revenues	$ 7	$ 5	$ 13	$ 11
Segment profit	$ 2	$ 18	$ 22	$ 25

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

The decrease in *segment profit* is primarily due to the absence of a $13 million gain on the sale of our interest in Accroven SRL in second-quarter 2010.

Six months ended June 30, 2011 vs. six months ended June 30, 2010

Segment profit in 2010 includes a $13 million gain on the sale of our interest in Accroven SRL in the second quarter, while 2011 includes the receipt of an $11 million payment in the first quarter. This receipt reflects the first of six quarterly payments, which was originally due from Petróleos de Venezuela S.A. (PDVSA) in October 2010. Payments are recognized as income upon receipt, until such point future collections are reasonably assured. 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 assumptions for the year:

- 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 remaining $308 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 $2.825 billion and $3.425 billion in 2011;

- We expect capital and investment expenditures to total between $3.125 billion and $3.825 billion in 2011. Of this total, a significant portion of Williams Partners expected expenditures of $1.41 billion to $1.735 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 $1.3 billion to $1.6 billion are considered primarily discretionary. Midstream Canada & Olefins expected expenditures of $350 million to $450 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.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2011. Our internal and external sources of consolidated liquidity

Management s Discussion and Analysis (Continued)
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.

			June 30, 2011	
Available Liquidity	**Expiration**	**WPZ**	**WMB**	**Total**
			(Millions)	
Cash and cash equivalents		$ 112	$ 1,054(1)	$ 1,166
Capacity available under our $900 million senior unsecured revolving credit facility (2)	June 3, 2016		900	900
Capacity available to Williams Partners L.P. under its $2 billion senior unsecured revolving credit facility (3) (4)	June 3, 2016	1,650		1,650
		$ 1,762	$ 1,954	$ 3,716

(1) *Cash and cash equivalents* includes $4 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 $548 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 June 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 June 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).

(4) Subsequent to June 30, 2011, WPZ repaid a net $100 million of the loans outstanding under the credit facility.

In addition to the credit facilities listed above, we have issued letters of credit totaling $74 million as of June 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.

Exploration & Production has an unsecured credit agreement with certain banks that, so long as certain conditions are met, serves to reduce our use of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. The agreement extends through December 2015. However, we expect this agreement will be terminated in conjunction with satisfying the conditions necessary for effectiveness of WPX s new credit facility. We also expect that WPX s ability to continue its hedging activities with minimal margin requirements will be provided through separate agreements with various banks.

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 indica 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 June 30, 2011, we estimate that a downgrade to a rating below investment grade for us or WPZ would require us to post up to $545 million or $51 million, respectively, in additional collateral with third parties.

Sources (Uses) of Cash

	Six months ended June 30,	
	2011	**2010**
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 1,684	$ 1,297
Financing activities	(114)	(630)

Investing activities	(1,199)	(933)
Increase (decrease) in cash and cash equivalents	$ 371	$ (266)

Management s Discussion and Analysis (Continued)

Operating activities

Our *net cash provided by operating activities* for the six months ended June 30, 2011 increased $387 million from the same period in 2010 primarily due to improved operating results and net favorable changes in working capital.

Financing activities

Significant transactions include:

- 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;

- $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 $1,094 million and $940 million for 2011 and 2010, respectively.

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.

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 six 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 June 30, 2011. The value at risk for contracts held for trading purposes was less than $1 million at June 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 $184 million at June 30, 2011.

The value at risk for derivative contracts held for nontrading purposes was $28 million at June 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 $182 million as of June 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.

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.

Second-Quarter 2011 Changes in Internal Controls

There have been no changes during the second 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

The information called for by this item is provided in Note 12 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 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 plan to separate our exploration and production business is delayed or not completed, our stock price may decline and our growth potential may not be enhanced.

On April 29, 2011, our wholly owned subsidiary, WPX Energy, Inc. (WPX), filed a registration statement with the SEC with respect to an initial public offering of its equity securities. This is the first step in our previously announced reorganization plan to divide our businesses into two separate, publicly traded corporations. The reorganization plan calls for a separation of our exploration and production business through an initial public offering 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. The completion and timing of these transactions is 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 Internal Revenue Service rulings, final approvals from our Board of Directors 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.

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.

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 10.1	Credit Agreement, dated as of June 3, 2011, by and among The Williams Companies, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent.(1)
Exhibit 10.2	Credit Agreement, dated as of June 3, 2011, by and among Williams Partners L.P., Northwest Pipeline GP, Transcontinental Gas Pipe Line Company, LLC, as co-borrowers, the lenders named therein, and Citibank N.A., as Administrative Agent.(1)
Exhibit 10.3	Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender.(1)
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.(2)
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.(2)
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.(2)
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.(2)
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.(2)
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.(2)

(1) Filed herewith.

(2) Furnished herewith.

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)

August 4, 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 10.1	Credit Agreement, dated as of June 3, 2011, by and among The Williams Companies, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent.(1)
Exhibit 10.2	Credit Agreement, dated as of June 3, 2011, by and among Williams Partners L.P., Northwest Pipeline GP, Transcontinental Gas Pipe Line Company, LLC, as co-borrowers, the lenders named therein, and Citibank N.A., as Administrative Agent.(1)
Exhibit 10.3	Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender.(1)
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.(2)
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.(2)
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.(2)
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.(2)
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(1) Filed herewith.

(2) Furnished herewith.