WILLIAMS COMPANIES INC
Form 10-Q
July 29, 2010

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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, 2010

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: (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 July 26, 2010
Common Stock, $1 par value	584,669,618 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 and natural gas liquids prices and demand.

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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 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 proposed climate change legislation 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.

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, 2009, and Part II, Item 1A. Risk Factors of this Form 10-Q.

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

(Millions, except per-share amounts)	Three months ended June 30, 2010	Three months ended June 30, 2009*	Six months ended June 30, 2010	Six months ended June 30, 2009*
Revenues:				
Williams Partners	$ 1,367	$ 1,081	$ 2,825	$ 2,038
Exploration & Production	910	809	2,078	1,785
Other	262	170	540	328
Intercompany eliminations	(247)	(151)	(555)	(320)
Total revenues	2,292	1,909	4,888	3,831
Segment costs and expenses:				
Costs and operating expenses	1,723	1,392	3,645	2,836
Selling, general, and administrative expenses	122	129	233	254
Other (income) expense net	(13)	(1)	(13)	32
Total segment costs and expenses	1,832	1,520	3,865	3,122
General corporate expenses	45	38	130	78
Operating income:				
Williams Partners	319	269	707	516
Exploration & Production	82	110	239	182
Other	59	10	77	11
General corporate expenses	(45)	(38)	(130)	(78)
Total operating income	415	351	893	631
Interest accrued	(154)	(167)	(318)	(329)
Interest capitalized	13	22	30	42
Investing income (loss)	55	24	94	(37)
Early debt retirement costs			(606)	
Other income (expense) net	(1)	1	(8)	(1)
Income from continuing operations before income taxes	328	231	85	306
Provision for income taxes	104	80	9	136
Income from continuing operations	224	151	76	170
Income (loss) from discontinued operations	(2)	18		(225)
Net income (loss)	222	169	76	(55)
Less: Net income (loss) attributable to noncontrolling interests	37	27	84	(25)
	$ 185	$ 142	$ (8)	$ (30)

Net income (loss) attributable to The Williams Companies, Inc.				
Amounts attributable to The Williams Companies, Inc.:				
Income (loss) from continuing operations	$ 187	$ 123	$ (8)	$ 125
Income (loss) from discontinued operations	(2)	19		(155)
Net income (loss)	$ 185	$ 142	$ (8)	$ (30)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ .32	$ .21	$ (.01)	$ .22
Income (loss) from discontinued operations		.03		(.27)
Net income (loss)	$ .32	$ .24	$ (.01)	$ (.05)
Weighted-average shares (thousands)	584,414	580,726	584,173	580,114
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ .31	$ .21	$ (.01)	$ .21
Income (loss) from discontinued operations		.03		(.26)
Net income (loss)	$ .31	$ .24	$ (.01)	$ (.05)
Weighted-average shares (thousands)	592,498	588,780	584,173	587,999
Cash dividends declared per common share	$ .125	$ .11	$ .235	$ .22

* Recast as discussed in Note 2.

See accompanying notes.

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

(Dollars in millions, except per-share amounts)	June 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,601	$ 1,867
Accounts and notes receivable (net of allowance of $15 at June 30, 2010 and $22 at December 31, 2009)	722	829
Inventories	279	222
Derivative assets	546	650
Other current assets and deferred charges	211	225
Total current assets	3,359	3,793
Investments	881	886
Property, plant, and equipment, at cost	28,497	27,625
Accumulated depreciation, depletion and amortization	(9,666)	(8,981)
Property, plant and equipment net	18,831	18,644
Derivative assets	309	444
Goodwill	1,011	1,011
Other assets and deferred charges	556	502
Total assets	$ 24,947	$ 25,280
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 806	$ 934
Accrued liabilities	838	948
Derivative liabilities	315	578
Long-term debt due within one year	160	17
Total current liabilities	2,119	2,477
Long-term debt	8,358	8,259
Deferred income taxes	3,724	3,656
Derivative liabilities	251	428
Other liabilities and deferred income	1,469	1,441
Contingent liabilities and commitments (Note 12)		
Equity:		
Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 619 million shares issued at June 30, 2010 and 618 million shares issued at December 31, 2009)	619	618

Capital in excess of par value	7,360	8,135
Retained earnings	758	903
Accumulated other comprehensive loss	(63)	(168)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders equity	7,633	8,447
Noncontrolling interests in consolidated subsidiaries	1,393	572
Total equity	9,026	9,019
Total liabilities and equity	$ 24,947	$ 25,280

See accompanying notes.

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

	Three months ended June 30,					
	2010			2009		
(Millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 7,573	$ 1,389	$ 8,962	$ 8,326	$ 530	$ 8,856
Comprehensive income:						
Net income	185	37	222	142	27	169
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	(42)	1	(41)	(158)		(158)
Foreign currency translation adjustments	(29)		(29)	32		32
Pension and other postretirement benefits net	5		5	5		5
Total other comprehensive income (loss)	(66)	1	(65)	(121)		(121)
Total comprehensive income	119	38	157	21	27	48
Cash dividends common stock	(73)		(73)	(64)		(64)
Dividends and distributions to noncontrolling interests		(34)	(34)		(32)	(32)
Stock-based compensation, net of tax	13		13	13		13
Issuance of common stock from 5.5% debentures conversion				28		28
Other	1		1		4	4
Ending balance	$ 7,633	$ 1,393	$ 9,026	$ 8,324	$ 529	$ 8,853

	Six months ended June 30,					
	2010			2009		
(Millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 8,447	$ 572	$ 9,019	$ 8,440	$ 614	$ 9,054

Comprehensive income (loss):						
Net income (loss)	(8)	84	76	(30)	(25)	(55)
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	105	3	108	(35)		(35)
Foreign currency translation adjustments	(10)		(10)	19		19
Pension and other postretirement benefits net	10		10	12		12
Total other comprehensive income (loss)	105	3	108	(4)		(4)
Total comprehensive income (loss)	97	87	184	(34)	(25)	(59)
Cash dividends common stock	(137)		(137)	(128)		(128)
Dividends and distributions to noncontrolling interests		(66)	(66)		(65)	(65)
Stock-based compensation, net of tax	25		25	18		18
Issuance of common stock from 5.5% debentures conversion				28		28
Change in Williams Partners L.P. ownership interest (Note 2)	(800)	800				
Other	1		1		5	5
Ending balance	$ 7,633	$ 1,393	$ 9,026	$ 8,324	$ 529	$ 8,853

See accompanying notes.

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

(Millions)	Six months ended June 30, 2010	2009
OPERATING ACTIVITIES:		
Net income (loss)	$ 76	$ (55)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation, depletion, and amortization	727	726
Provision (benefit) for deferred income taxes	50	(18)
Provision for loss on investments, property and other assets	10	341
Provision for doubtful accounts and notes	(7)	51
Amortization of stock-based awards	26	25
Early debt retirement costs	606	
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	115	244
Inventories	(57)	6
Margin deposits and customer margin deposits payable	5	(15)
Other current assets and deferred charges	(6)	(34)
Accounts payable	(89)	(55)
Accrued liabilities	(157)	(138)
Changes in current and noncurrent derivative assets and liabilities	(34)	29
Other, including changes in noncurrent assets and liabilities	32	27
Net cash provided by operating activities	1,297	1,134
FINANCING ACTIVITIES:		
Proceeds from long-term debt	3,749	595
Payments of long-term debt	(3,515)	(31)
Dividends paid	(137)	(128)
Dividends and distributions paid to noncontrolling interests	(66)	(65)
Payments for debt issuance costs	(66)	(7)
Premiums paid on early debt retirements	(574)	
Changes in restricted cash	(1)	38
Changes in cash overdrafts	(13)	(61)
Other net	(7)	2
Net cash provided (used) by financing activities	(630)	343
INVESTING ACTIVITIES:		
Capital expenditures*	(940)	(1,077)
Purchases of investments/advances to affiliates	(20)	(129)
Distribution from Gulfstream Natural Gas System, L.L.C.		148
Other net	27	(5)
Net cash used by investing activities	(933)	(1,063)

Increase (decrease) in cash and cash equivalents	(266)	414
Cash and cash equivalents at beginning of period	1,867	1,439
Cash and cash equivalents at end of period	$ 1,601	$ 1,853

* Increases to property, plant, and equipment	$ (898)	$ (904)
Changes in related accounts payable and accrued liabilities	(42)	(173)
Capital expenditures	$ (940)	$ (1,077)

See accompanying notes.

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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 May 26, 2010. The accompanying unaudited financial statements include all normal recurring adjustments that, in the opinion of our management, are necessary to present fairly our financial position at June 30, 2010, results of operations and changes in equity for the three and six months ended June 30, 2010 and 2009 and cash flows for the six months ended June 30, 2010 and 2009.

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 17, 2010, we completed a strategic restructuring that involved contributing certain of our wholly and partially owned subsidiaries to Williams Partners L.P. (WPZ), our consolidated master limited partnership, and restructuring our debt (see Note 9). As discussed further in Note 2, we have revised our segment presentation as a result of this strategic restructuring.

Goodwill

We perform interim assessments of goodwill if impairment triggering events or circumstances are present. One such triggering event is a significant decline in forward natural gas prices. Forward natural gas prices as of June 30, 2010, have declined compared to those used in our prior year-end analysis. We have evaluated the impact of this decline across all future production periods. Considering this and certain other factors, we determined that the impact was not significant enough to warrant a full impairment review. It is reasonably possible that we may be required to conduct an interim goodwill impairment evaluation during the remainder of 2010, which could result in a material impairment of goodwill.

Note 2. Basis of Presentation

Strategic Restructuring

Our strategic restructuring completed during the first quarter of 2010 resulted in contributing businesses that were in our previously reported Gas Pipeline and Midstream Gas & Liquids (Midstream) segments into our consolidated master limited partnership, WPZ. The contributed Gas Pipeline businesses included 100 percent of Transcontinental Gas Pipe Line Company, LLC (Transco), 65 percent of Northwest Pipeline GP (Northwest Pipeline), and 24.5 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream). We also contributed our general and limited partner interests in Williams Pipeline Partners L.P. (WMZ), which owns the remaining 35 percent of Northwest Pipeline. The contributed Midstream businesses include significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, as well as a business in Pennsylvania s Marcellus Shale region, and various equity investments in domestic processing and fractionation assets. Our remaining 25.5 percent ownership interest in Gulfstream and our Canadian, Venezuelan, and olefins operations were excluded from the transaction. Additionally, our Exploration & Production segment was not included in this transaction.

As a result of the restructuring, we have changed our segment reporting structure to align with the new parent-level focus employed by our chief operating decision-maker considering the resource allocation and governance associated with managing WPZ as a distinctly separate entity. Beginning first quarter 2010, our reportable segments are Williams Partners, Exploration & Production, and Other.

William Partners consists of our consolidated master limited partnership WPZ, including the gas pipeline and midstream businesses that were contributed as part of our previously described strategic restructuring. WPZ also includes other significant midstream operations and investments in the Four Corners and Gulf Coast regions, as well as a natural gas liquids (NGL) fractionator and storage facilities near Conway, Kansas.

Notes (Continued)

Exploration & Production includes natural gas development, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States, development activities in the Eastern portion of the United States and oil and natural gas interests in South America. 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 the managing of various natural gas related contracts such as transportation, storage and related hedges not utilized for our own production.

Other includes our Canadian midstream and domestic olefins operations, a 25.5 percent interest in Gulfstream, as well as corporate operations.

Prior periods have been recast to reflect this revised segment presentation.

Master Limited Partnerships

Upon completing our strategic restructuring, we now own approximately 84 percent of the interests in WPZ, including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Prior to the restructuring, we owned approximately 23.6 percent of WPZ and consolidated it due to our control of the general partner. The change in WPZ ownership between us and the noncontrolling interests has been accounted for as an equity transaction, resulting in an $800 million decrease to *capital in excess of par value* and a corresponding increase to *noncontrolling interests in consolidated subsidiaries*.

WPZ is expected to be 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, are expected to occur through the normal partnership distributions from WPZ to all partners.

As of June 30, 2010, WPZ owns approximately 47.7 percent of the interests in WMZ, including the interests of the general partner, which is wholly owned by WPZ, and incentive distribution rights. WPZ consolidates WMZ due to its control through the general partner.

On May 24, 2010, WPZ and WMZ entered into a merger agreement (Merger Agreement) providing for the merger of WMZ into WPZ (the Merger). The Merger and the Merger Agreement are described in detail in the Registration Statement on Form S-4 initially filed by WPZ on June 9, 2010 and in WPZ s and WMZ s joint proxy statement/prospectus dated July 15, 2010 that is being provided to holders of record of WMZ s units at the close of business on July 15, 2010, who are the holders of WMZ s units who will be entitled to vote on the Merger at the special meeting of WMZ s unitholders scheduled for August 31, 2010. If the Merger is approved at that meeting, it is anticipated that the Merger will be consummated shortly thereafter, and all of WMZ s units not already held by WPZ will be exchanged for WPZ units at an exchange ratio of 0.7584 of WPZ units for each WMZ unit. Assuming the Merger is completed, WPZ will own a 100 percent interest in Northwest Pipeline GP and we will hold an approximate 80 percent interest in WPZ, comprised of an approximate 78 percent limited partner interest and all of WPZ s 2 percent general partner interest.

Discontinued Operations

The accompanying consolidated financial statements and notes reflect the results of operations and financial position of certain of our Venezuela operations and other former businesses as discontinued operations. (See Note 3.)

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

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Notes (Continued)

Note 3. Discontinued Operations

Summarized Results of Discontinued Operations

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
	(Millions)		(Millions)	
Income (loss) from discontinued operations before impairments, gain on deconsolidation and income taxes	$ (1)	$ 18	$ 4	$ (84)
Impairments				(211)
Gain on deconsolidation		9		9
(Provision) benefit for income taxes	(1)	(9)	(4)	61
Income (loss) from discontinued operations	$ (2)	$ 18	$	$ (225)
Income (loss) from discontinued operations:				
Attributable to noncontrolling interests	$	$ (1)	$	$ (70)
Attributable to The Williams Companies, Inc.	$ (2)	$ 19	$	$ (155)

Income (loss) from discontinued operations before impairments, gain on deconsolidation and income taxes for the three months ended June 30, 2009, includes a $15 million gain related to our former coal operations.

Income (loss) from discontinued operations before impairments, gain on deconsolidation and income taxes for the six months ended June 30, 2009, primarily includes losses from our discontinued Venezuela operations, including $48 million of bad debt expense and a $30 million net charge related to the write-off of certain deferred charges and credits. Offsetting these losses is the previously discussed $15 million gain related to our former coal operations.

Impairments for the six months ended June 30, 2009, reflects a $211 million impairment of our Venezuela property, plant, and equipment. (See Note 10.)

(Provision) benefit for income taxes for the six months ended June 30, 2009, includes a $76 million benefit from the reversal of deferred tax balances related to our discontinued Venezuela operations.

Note 4. Asset Sales, Impairments and Other Accruals

Other (income) expense net within *segment costs and expenses* for the six months ending June 30, 2009 includes Exploration & Production s $32 million of penalties from the early release of drilling rigs.

Additional Items

We completed a strategic restructuring transaction in the first quarter of 2010 that involved significant debt issuances, retirements and amendments (see Note 9). We incurred significant costs related to these transactions, as follows:

$606 million of early debt retirement costs consisting primarily of cash premiums of $574 million;

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

$4 million of accelerated amortization of debt costs related to the amendments of credit facilities, reflected in *other income (expense) net* below *operating income*.

In first-quarter 2009, considering the deteriorating circumstances in Venezuela, Other recorded a $75 million impairment charge related to an other-than-temporary loss in value associated with our Venezuelan investment in Accroven SRL (Accroven), which is reflected in loss from investments within *investing income (loss)* at Other. (See Note 10.) In June 2010, we sold our 50 percent interest in

Notes (Continued)

Accroven to Petróleos de Venezuela S.A. (PDVSA) for $107 million. Of this amount, $13 million was received in cash at closing and is reflected as a gain within *investing income (loss)* at Other. Another $30 million is due on July 31, 2010, and the remainder is due in six quarterly payments beginning October 31, 2010. We are currently recognizing the resulting gain as cash is received. In connection with this sale, PDVSA also repaid Accroven s outstanding debt balances directly to the lenders.

In addition, Exploration & Production recorded an $11 million impairment related to a Venezuelan cost-based investment in first-quarter 2009, which is included within *investing income (loss)*. (See Note 10.)

In second-quarter 2009, Exploration & Production recognized $11 million of income related to the recovery of certain royalty overpayments from prior periods, which is reflected within *revenues*.

Note 5. Provision for Income Taxes

The *provision for income taxes* from continuing operations includes:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
	(Millions)		(Millions)	
Current:				
Federal	$ 70	$ 44	$ (45)	$ 56
State	5	5	(9)	7
Foreign	8	10	13	14
	83	59	(41)	77
Deferred:				
Federal	15	23	39	57
State	3	3	6	7
Foreign	3	(5)	5	(5)
	21	21	50	59
Total provision	$ 104	$ 80	$ 9	$ 136

The effective income tax rate on the total provision for the three 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 effect of state income taxes. The effective income tax rate on the total provision for the three months ended June 30, 2009, is approximately equal to the federal statutory rate due primarily to offsetting impacts of state income taxes reduced by nontaxable noncontrolling interests.

The effective income tax rate on 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 healthcare legislation. The effective income tax rate on the total provision for the six months ended June 30, 2009, is greater than the federal statutory rate primarily due to the effect of state income taxes and the limitation of tax benefits associated with impairments of certain Venezuelan investments (see Note 4), partially offset by the impact of nontaxable noncontrolling interests.

During the next 12 months, we cannot predict with certainty whether we will achieve ultimate resolution of any uncertain tax position associated with a domestic or international matter that will result in a significant increase or decrease of our unrecognized tax benefit. However, certain matters we have contested to the Internal Revenue Service Appeals Division could be resolved and result in a reduction to our unrecognized tax benefit.

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Notes (Continued)

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

	Three months ended June 30, 2010		Three months ended June 30, 2009		Six months ended June 30, 2010		Six months ended June 30, 2009	
	(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)	$	187	$	123	$	(8)	$	125
Basic weighted-average shares		584,414		580,726		584,173		580,114
Effect of dilutive securities:								
Nonvested restricted stock units		2,826		1,773				1,589
Stock options		3,022		1,884				1,674
Convertible debentures		2,236		4,397				4,622
Diluted weighted-average shares		592,498		588,780		584,173		587,999
Earnings (loss) per common share from continuing operations:								
Basic	$	.32	$	.21	$	(.01)	$	.22
Diluted	$	.31	$	.21	$	(.01)	$	.21

(1) The three-month period ended June 30, 2010 includes $0.2 million and the three- and six-month periods ended June 30, 2009, includes $0.4 million and $0.8 million, respectively, of interest expense, net of tax, associated with our convertible debentures. This amount has been added back to *income*

(loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders to calculate diluted earnings per common share.

For the 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.

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,	
	2010	**2009**
Options excluded (millions)	3.3	6.7
Weighted-average exercise price of options excluded	$ 29.44	$ 25.60
Exercise price ranges of options excluded	$ 21.55 - $40.51	$ 15.71 - $42.29
Second quarter weighted-average market price	$ 21.54	$ 14.95

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Note 7. Employee Benefit Plans

Net periodic benefit expense is as follows:

	Pension Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
	(Millions)			
Components of net periodic pension expense:				
Service cost	$ 10	$ 9	$ 18	$ 16
Interest cost	16	16	32	31
Expected return on plan assets	(17)	(16)	(35)	(30)
Amortization of prior service cost		1		1
Amortization of net actuarial loss	8	10	17	21
Net periodic pension expense	$ 17	$ 20	$ 32	$ 39

	Other Postretirement Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
	(Millions)			
Components of net periodic other postretirement benefit expense:				
Service cost	$	$ 1	$ 1	$ 1
Interest cost	4	4	8	8
Expected return on plan assets	(2)	(2)	(5)	(4)
Amortization of prior service credit	(4)	(3)	(7)	(5)
Amortization of net actuarial loss	1		1	1
Amortization of regulatory asset	1	1	1	2
Net periodic other postretirement benefit expense (income)	$	$ 1	$ (1)	$ 3

During the six months ended June 30, 2010, we contributed $31 million to our pension plans and $8 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $30 million to our pension plans and approximately $8 million to our other postretirement benefit plans in the remainder of 2010.

Note 8. Inventories

	June 30, 2010	December 31, 2009
	(Millions)	
Natural gas liquids and olefins	$ 70	$ 70
Natural gas in underground storage	87	47
Materials, supplies, and other	122	105

	$ 279	$ 222

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Note 9. Debt and Banking Arrangements

Revolving Credit and Letter of Credit Facilities (Credit Facilities)

At June 30, 2010, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Credit Facilities Expiration	Letters of Credit at June 30, 2010 (Millions)	
$700 million unsecured credit facilities	October 2010	$	133
$900 million unsecured credit facility	May 2012		27
$1.75 billion Williams Partners L.P. unsecured credit facility	February 2013		
		$	160

As part of our strategic restructuring (see Note 2), WPZ entered into a new $1.75 billion three-year senior unsecured revolving credit facility with Transco and Northwest Pipeline as co-borrowers. This credit facility replaced an unsecured $450 million credit facility, comprised of a $200 million revolving credit facility and a $250 million term loan which was terminated as part of the restructuring. At the closing, WPZ utilized $250 million of the credit facility to repay the outstanding term loan. As of June 30, 2010, no loans are outstanding under the credit facility. The credit facility expires February 15, 2013, and may, under certain conditions, be increased by up to an additional $250 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 WPZ. Each time funds are borrowed, the 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. WPZ is required to pay a commitment fee (currently 0.5 percent) based on the unused portion of the credit facility. The applicable margin and the commitment fee are based on the specific borrower s senior unsecured long-term debt ratings. The credit facility contains various covenants that limit, among other things, a borrower s and its respective subsidiaries ability to incur indebtedness, grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default, and allow any material change in the nature of its business. Significant financial covenants under the credit facility include:

WPZ ratio of debt to EBITDA (each as defined in the credit facility) must be no greater than 5 to 1.

The ratio of debt to capitalization (defined as net worth plus debt) must be no greater than 55 percent for Transco and Northwest Pipeline.

Each of the above ratios are tested at the end of each fiscal quarter, and the debt to EBITDA ratio is measured on a rolling four-quarter basis (with the first full year measured on an annualized basis). At June 30, 2010, we are in compliance with these financial covenants.

The credit facility includes customary events of default. If an event of default with respect to a borrower occurs under the credit facility, the lenders will be able to terminate the commitments for all borrowers and accelerate the maturity of the loans of the defaulting borrower under the credit facility and exercise other rights and remedies.

As WPZ will be funding projects for its midstream and gas pipeline businesses, we reduced our $1.5 billion unsecured credit facility that expires May 2012 to $900 million and removed Transco and Northwest Pipeline as borrowers.

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In second-quarter 2010, there were no changes to our $700 million unsecured credit facilities, which mature in October 2010, or to our unsecured credit facility used to facilitate our natural gas production hedging, which was due to expire in December 2013. In July 2010, the term of our facility expiring in December 2013 was extended to December 2015.

Issuances and Retirements

In connection with the restructuring, WPZ issued $3.5 billion face value of senior unsecured notes as follows:

		(Millions)
3.80% Senior Notes due 2015	$	750
5.25% Senior Notes due 2020		1,500
6.30% Senior Notes due 2040		1,250
Total	$	3,500

Prior to the issuance of this debt, WPZ entered into forward starting interest rate swaps to hedge against variability in interest rates on a portion of the anticipated debt issuance. Upon the issuance of the debt, these instruments were terminated, which resulted in a payment of $7 million. This amount has been recorded in *accumulated other comprehensive loss* and is being amortized over the term of the related debt.

As part of the issuance of the $3.5 billion unsecured notes, WPZ entered into registration rights agreements with the initial purchasers of the notes. An offer to exchange these unregistered notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended, was commenced in June 2010 and completed in July 2010.

With the debt proceeds discussed above, we retired $3 billion of debt and paid $574 million in related premiums. The $3 billion of aggregate principal corporate debt retired includes:

		(Millions)
7.125% Notes due 2011	$	429
8.125% Notes due 2012		602
7.625% Notes due 2019		668
8.75% Senior Notes due 2020		586
7.875% Notes due 2021		179
7.70% Debentures due 2027		98
7.50% Debentures due 2031		163
7.75% Notes due 2031		111
8.75% Notes due 2032		164
Total	$	3,000

As a result of the changes in debt noted above, the weighted-average interest rate for unsecured fixed rate notes decreased from 7.7 percent at December 31, 2009 to 6.6 percent at June 30, 2010.

Note 10. Fair Value Measurements

Fair value is the amount received to sell an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement considered from the perspective of a market participant. We use market data or assumptions that we believe market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We apply both market and income approaches for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

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Notes (Continued)

The fair value hierarchy prioritizes the inputs used to measure fair value, giving the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices for identical assets or liabilities in active markets that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements primarily consist of financial instruments that are exchange traded.

Level 2 Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 measurements primarily consist of over-the-counter (OTC) instruments such as forwards, swaps, and options.

Level 3 Inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management s best estimate of the assumptions market participants would use in determining fair value. Our Level 3 measurements consist of instruments that are valued utilizing unobservable pricing inputs that are significant to the overall fair value.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

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, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Assets:								
Energy derivatives	$ 158	$ 681	$ 16	$ 855	$ 178	$ 911	$ 5	$ 1,094
ARO Trust Investments (see Note 11)	33			33	22			22
Total assets	$ 191	$ $681	$ 16	$ 888	$ 200	$ 911	$ 5	$ 1,116
Liabilities:								
Energy derivatives	$ 143	$ 421	$ 2	$ 566	$ 177	$ 826	$ 3	$ 1,006
Total liabilities	$ 143	$ 421	$ 2	$ 566	$ 177	$ 826	$ 3	$ 1,006

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures, swaps, and options. OTC contracts include forwards, swaps and options.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting

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Notes (Continued)

arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

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.

Our 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 36 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.

Certain instruments trade in less active markets with lower availability of pricing information. 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 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at June 30, 2010, consist of NGL swaps and forward contracts for our midstream businesses, including those in our Williams Partners segment, as well as natural gas index transactions that are used to manage the physical requirements of our Exploration & Production segment.

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 in or out of Level 1 and Level 2 occurred during the period ended June 30, 2010. During the third quarter of 2009, certain Exploration & Production options which hedge future sales of production were transferred from Level 3 to Level 2. These options were originally included in Level 3 because a significant input to the model, implied volatility by location, was considered unobservable. Due to increased transparency, this input was considered observable, and we transferred these options to Level 2.

Notes (Continued)

The following tables present a reconciliation of changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Three months ended June 30, 2010 Net Energy Derivatives	Three months ended June 30, 2010 Other Assets	Three months ended June 30, 2009 Net Energy Derivatives	Three months ended June 30, 2009 Other Assets
	(Millions)			
Beginning balance	$ 5	$	$ 639	$ 7
Realized and unrealized gains (losses):				
Included in income from continuing operations	(1)		182	
Included in other comprehensive income (loss)	11		(229)	
Purchases, issuances, and settlements	(1)		(179)	(7)
Transfers into Level 3				
Transfers out of Level 3				
Ending balance	$ 14	$	$ 413	$
Unrealized gains (losses) included in income from continuing operations relating to instruments still held at June 30	$ (1)	$	$ 4	$

	Six months ended June 30, 2010 Net Energy Derivatives	Six months ended June 30, 2010 Other Assets	Six months ended June 30, 2009 Net Energy Derivatives	Six months ended June 30, 2009 Other Assets
	(Millions)			
Beginning balance	$ 2	$	$ 507	$ 7
Realized and unrealized gains (losses):				
Included in income from continuing operations	(1)		319	
Included in other comprehensive income (loss)	15		(96)	
Purchases, issuances, and settlements	(2)		(317)	(7)
Transfers into Level 3				
Transfers out of Level 3				
Ending balance	$ 14	$	$ 413	$
Unrealized gains (losses) included in income from continuing operations relating to instruments still held at June 30	$ (1)	$	$ 3	$

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

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The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy. Certain of these items have been reported within discontinued operations.

		Total losses for three months ended June 30,		Total losses for six months ended June 30,	
		2010	2009	2010	2009
		(Millions)		(Millions)	
Impairments:					
Venezuelan property	Discontinued Operations	$	$	$	$ 211(a)
Investment in Accroven	Other				75(b)
Cost-based investment	Exploration & Production				11(c)
		$	$	$	$ 297

(a) Fair value measured at March 31, 2009, was $106 million. This value was based on our estimates of probability-weighted discounted cash flows that considered (1) the continued operation of the assets considering different scenarios of outcome, (2) the purchase of the assets by PDVSA, (3) the results of arbitration with varying degrees of award and collection, and (4) an after-tax discount rate of 20 percent.

(b) Fair value measured at March 31, 2009, was zero. This value was determined based on a probability-weighted discounted cash flow analysis that considered the deteriorating circumstances in Venezuela.

(c) Fair value measured at March 31, 2009, was zero. This value was based on an other-than-temporary decline in the value of our investment considering the deteriorating financial condition of a Venezuelan corporation in which Exploration & Production has a 4 percent interest.

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.

ARO Trust Investments: Our Transco subsidiary deposits a portion of its collected rates, pursuant to its 2008 rate case settlement, into an external trust specifically designated to fund future asset retirement obligations (ARO Trust). 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, 2010 and December 31, 2009, approximately 59 percent and 97 percent, respectively, of our long-term debt was publicly traded. (See Note 9.)

Guarantees: The *guarantees* represented in the following table consist primarily of guarantees we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on certain lease performance obligations. To estimate the fair value of the guarantees, the estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate for each

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guarantee based on the credit rating of 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.

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 discussion of valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments

	June 30, 2010		December 31, 2009	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
		(Millions)		
Cash and cash equivalents	$ 1,601	$ 1,601	$ 1,867	$ 1,867
Restricted cash (current and noncurrent)	$ 29	$ 29	$ 28	$ 28
ARO Trust Investments	$ 33	$ 33	$ 22	$ 22
Long-term debt, including current portion (a)	$(8,514)	$(9,168)	$(8,273)	$(9,142)
Guarantees	$ (36)	$ (34)	$ (36)	$ (33)
Other	$ (29)	$ (31)(b)	$ (23)	$ (25)(b)
Net energy derivatives:				
Energy commodity cash flow hedges	$ 332	$ 332	$ 178	$ 178
Other energy derivatives	$ (43)	$ (43)	$ (90)	$ (90)

(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 $2 million at June 30, 2010 and December 31, 2009.

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 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 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 market prices, we enter into natural gas futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. These 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.

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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. These 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:

Fixed price: Includes physical and financial derivative transactions that settle at a fixed location price;

Basis: Includes financial derivative transactions priced off the difference in value between a commodity at two specific delivery points;

Index: Includes physical derivative transactions 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.

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of June 30, 2010. Natural gas is presented in millions of British Thermal Units (MMBtu), and NGLs is presented in gallons. 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 long positions on behalf of other segments.

Derivative Notional Volumes		Meas.	Fixed Price	Basis	Index	Options
Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(166,285,000)	(165,445,000)		(194,215,000)
Williams Partners	Risk Management	MMBtu	11,460,000	7,615,000		
Williams Partners	Risk Management	Gallons	(126,294,000)			
Not Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(10,432,499)	(8,227,500)	1,775,762	
Williams Partners	Risk Management	Gallons	(3,570,000)			
Other	Risk Management	Gallons	10,500,000			
Exploration & Production	Other	MMBtu	180,000	(1,487,500)		(250,000)

Notes (Continued)

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, 2010		December 31, 2009	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Designated as hedging instruments	$ 391	$ 59	$ 352	$ 174
Not designated as hedging instruments:				
Legacy natural gas contracts from former power business	327	338	505	526
All other	137	169	237	306
Total derivatives not designated as hedging instruments	464	507	742	832
Total derivatives	$ 855	$ 566	$ 1,094	$ 1,006

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

	Three months ended June 30,		Six months ended June 30,		
	2010	2009	2010	2009	Classification
	(Millions)		(Millions)		
Net gain (loss) recognized in other comprehensive income (effective portion)	$ 32	$ (54)	$ 310	$ 271	AOCI
Net gain reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$ 100	$ 201	$ 125	$ 330	Revenues
Gain (loss) recognized in income (ineffective portion)	$ (2)	$ 1	$ 3	$ 2	Revenues

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,	
	2010	2009	2010	2009
	(Millions)		(Millions)	
Revenues	$ (15)	$ 5	$ 11	$ 20
Costs and operating expenses	7	10	7	14

Net gain (loss)	$	(22)	$	(5)	$	4	$	6

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*.

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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, 2010, we have collateral totaling $56 million, all of which is in the form of letters of credit, posted to derivative counterparties to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $101 million, which includes a reduction of $1 million to our liability balance for our own nonperformance risk. At December 31, 2009, we had collateral totaling $96 million posted to derivative counterparties, all of which was in the form of letters of credit, to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $167 million, which included a reduction of $3 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 $46 million and $74 million at June 30, 2010 and December 31, 2009, respectively.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in other comprehensive income 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, 2010, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to three years. Based on recorded values at June 30, 2010, $151 million of net gains (net of income tax provision of $91 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, 2010. 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

In addition to the guarantees and payment obligations discussed in Note 12, we have issued guarantees and other similar arrangements as discussed below.

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 guarantees in the event of nonpayment by our previously owned communications subsidiary, WilTel, on certain lease performance obligations that extend through 2042. The maximum potential exposure is approximately $39 million at June 30, 2010. Our exposure declines systematically throughout the remaining term of

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Notes (Continued)

WilTel s obligations. The carrying value of these guarantees included in *accrued liabilities* on the Consolidated Balance Sheet is $36 million at June 30, 2010.

At June 30, 2010, 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 a material 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, 2010, is summarized as follows.

Counterparty Type	**Investment Grade(a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 19	$ 19
Energy marketers and traders		239
Financial institutions	597	597
	$ 616	855
Credit reserves		
Gross credit exposure from derivatives		$ 855

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, 2010, excluding collateral support discussed below, is summarized as follows.

Counterparty Type	**Investment Grade(a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 11	$ 11
Energy marketers and traders		5
Financial institutions	374	374
	$ 385	390
Credit reserves		
Net credit exposure from derivatives		$ 390

(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 eight largest net counterparty positions represent approximately 93 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are six counterparty positions, representing 73 percent of our net credit exposure from derivatives, associated with Exploration &

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Notes (Continued)

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, 2010, the designated collateral agent holds $40 million of collateral support on our behalf under Exploration & Production s hedging facility. In addition, we hold collateral support, which may include cash or letters of credit, of $25 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 U.S. Federal Energy Regulatory Commission (FERC). These challenges included refund proceedings, summer 2002 90-day contracts, investigations of alleged market manipulation including withholding, gas indices and other gaming of the market, new long-term power sales to the State of California that were subsequently challenged and civil litigation relating to certain of these issues. 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.

As a result of a June 2008 U.S. Supreme Court decision, certain contracts that we entered into during 2000 and 2001 may be subject to partial refunds depending on the results of further proceedings at the FERC. These contracts, under which we sold electricity, totaled approximately $89 million in revenue. While we are not a party to the cases involved in the U.S. Supreme Court decision, the buyer of electricity from us is a party to the cases and claims that we must refund to the buyer any loss it suffers due to the FERC s reconsideration of the contract terms at issue in the decision. The FERC has directed the parties to provide additional information on certain issues remanded by the U.S. Supreme Court, but delayed the submission of this information to permit the parties to explore possible settlements of the contractual disputes. The parties to the remanded proceeding have engaged the FERC s Dispute Resolution Service to assist with settlement discussions.

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

Refund proceedings

Although we entered into the State Settlement and Utilities Settlement, which resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, such as the counterparty to the contracts described above and various California end users that did not participate in the Utilities Settlement. As a part of the Utilities Settlement, we funded escrow accounts that will be used towards satisfying any ultimate refund determinations in favor of the nonsettling parties including interest on refund amounts that we might owe to settling and nonsettling parties. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling $24 million at June 30, 2010. Collection of the interest and the payment of interest on refund amounts from the escrow accounts are subject to the conclusion of this proceeding. Therefore, we continue to participate in the FERC refund case and related proceedings.

Challenges to virtually every aspect of the refund proceedings, including the refund period, continue to be made. Despite two FERC decisions that will affect the refund calculation, significant aspects of the refund calculation process remain unsettled, and the final refund calculation has not been made. Because of our settlements, we do not expect that the final resolution of refund obligations will have a material impact on us.

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

Notes (Continued)

litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri, Tennessee and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states.

The federal court in Nevada currently presides over cases that were transferred to it from state courts in Colorado, Kansas, Missouri, and Wisconsin. In 2008, the federal court in Nevada granted summary judgment in the Colorado case in favor of us and most of the other defendants, and on January 8, 2009, the court denied the plaintiffs request for reconsideration of the Colorado dismissal. We expect that the Colorado plaintiffs will appeal, but the appeal cannot occur until the case against the remaining defendant is concluded.

On April 23, 2010, the Tennessee Supreme Court reversed the state appellate court and dismissed the plaintiffs claims against us on federal preemption grounds. The plaintiffs will not appeal this ruling to the United States Supreme Court.

On December 8, 2009, the Missouri appellate court upheld the trial court s dismissal of a case for lack of standing. The plaintiff has appealed to the Missouri Supreme Court.

Environmental Matters

Continuing operations

Since 1989, our Transco subsidiary has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At June 30, 2010, we had accrued liabilities of $4 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, we have estimated our aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above. We expect that these costs will be recoverable through Transco s rates.

Beginning in the mid-1980s, our Northwest Pipeline GP (Northwest Pipeline) subsidiary evaluated many of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation might be necessary. Consistent with other natural gas transmission companies, Northwest Pipeline identified PCB contamination in air compressor systems, soils and related properties at certain compressor station sites. Similarly, Northwest Pipeline identified hydrocarbon impacts at these facilities due to the former use of earthen pits and mercury contamination at certain gas metering sites. The PCBs were remediated pursuant to a Consent Decree with the EPA in the late 1980s and Northwest Pipeline conducted a voluntary clean-up of the hydrocarbon and mercury impacts in the early 1990s. In 2005, the Washington Department of Ecology required Northwest Pipeline to reevaluate its previous mercury clean-ups in Washington. Consequently, Northwest Pipeline is conducting additional assessments and remediation activities at certain sites to comply with Washington s current environmental standards. At June 30, 2010, we have accrued liabilities of $7 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

In March 2008, the EPA issued new air quality standards for ground level ozone. In September 2009, the EPA announced that it would reconsider those standards. In January 2010, the EPA proposed more stringent standards, which are expected to be final in the third quarter 2010. The EPA expects that new eight-hour ozone nonattainment areas will be designated in July 2011. The new standards and nonattainment areas will likely impact the operations of our interstate gas pipelines and cause us to incur additional capital expenditures to comply. At this time we are unable to estimate the cost that may be required to meet these regulations. We expect that costs associated with these compliance efforts will be recoverable through rates.

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Notes (Continued)

In February 2010, the EPA promulgated a final rule establishing a new one-hour nitrogen dioxide (NO2) National Ambient Air Quality Standard. The effective date of the new NO2 standard was April 12, 2010. This new standard is subject to numerous challenges in federal court. We are unable at this time to estimate the cost of additions that may be required to meet this new regulation.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At June 30, 2010, we have accrued liabilities totaling $7 million for these costs.

In April 2010, we entered into a global settlement with the New Mexico Environmental Department s Air Quality Bureau (NMED) to resolve allegations of various air emissions violations at certain of our facilities. The settlement resolves notices of violation (NOVs) dating back to 2007 and includes a $400,000 penalty, as well as environmental projects totaling $1.35 million.

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. We met with the EPA and are exchanging information in order to resolve the issues.

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 NOVs alleging violations of Clean Air Act requirements at these compressor stations. We met with the EPA in May 2008 and submitted our response denying the allegations in June 2008. In July 2009, the EPA requested additional information pertaining to these compressor stations and in August 2009, we submitted the requested information.

In January 2010, the Colorado Department of Public Health and Environment (CDPHE) proposed a penalty against Williams Production RMT Company for alleged permit violations at four compressor stations in Colorado. A settlement was reached with the CDPHE in March 2010 wherein we paid a penalty of $96,750.

In July 2010, Williams Production RMT Company and the Colorado Oil and Gas Commission (COGCC) reached an agreement on the terms of an Administrative Order in Consent (AOC) addressing a release of hydrocarbons from a production pit in Garfield County, Colorado. That AOC includes a $423,300 penalty.

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 include those described below.

- Potential indemnification obligations to purchasers of our former agricultural fertilizer and chemical operations and former retail petroleum and refining operations;
- Former propane marketing operations, bio-energy facilities, petroleum products and natural gas pipelines;
- Discontinued petroleum refining facilities;
- Former exploration and production and mining operations.

At June 30, 2010, we have accrued environmental liabilities of $23 million related to these matters.

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.

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Notes (Continued)

Summary of environmental matters

Actual costs incurred 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 and other factors, but any incremental amount cannot be reasonably estimated at this time.

Other Legal Matters

Will Price (formerly Quinque)

In 2001, 14 of our entities were named as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs and sought an unspecified amount of damages. The fourth amended petition, which was filed in 2003, deleted all of our defendant entities except two Midstream subsidiaries. All remaining defendants opposed class certification and on September 18, 2009, the court denied plaintiffs most recent motion to certify the class. On October 2, 2009, the plaintiffs filed a motion for reconsideration of the denial. On March 31, 2010, the court entered an order denying plaintiffs motion for reconsideration and as a result, there are no class action allegations remaining in the case.

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. If the judgment is upheld on appeal, our remaining liability will be substantially 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 Colorado state court alleging that we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. We reached a final partial settlement agreement for an amount that was previously accrued. We received a favorable ruling on our motion for summary judgment on one claim now on appeal by plaintiffs. We do not anticipate trial on the other remaining issue related to royalty payment calculation and obligations under specific lease provisions before 2011. While we are not able to estimate the amount of any additional exposure at this time, it is reasonably possible that plaintiff s claims could reach a material amount.

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Notes (Continued)

Other producers have been in litigation or discussions with a federal regulatory agency and a state agency in New Mexico regarding certain deductions 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 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.

Other Divestiture Indemnifications

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

At June 30, 2010, 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

In February 2010, we completed our strategic restructuring that resulted in a revision to our segment reporting structure. Beginning with first-quarter 2010 reporting, our reportable segments are Williams Partners, Exploration & Production, and Other. (See Note 2.)

Our segment presentation of Williams Partners is reflective of the parent-level focus by our chief operating decision-maker, considering the resource allocation and governance provisions associated with this master limited partnership structure. Following our restructuring, this entity maintains a capital and cash management structure that is separate from ours. Williams Partners is expected to be self-funding and maintains its own lines of bank credit and cash management accounts. These factors, coupled with a different cost of capital from our other businesses, serve to differentiate the management of this entity as a whole.

Performance Measurement

We currently evaluate segment operating 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;

Other — commodity purchases (primarily for shrink, feedstock and NGL and olefin marketing activities), depreciation and operation and maintenance expenses.

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Notes (Continued)

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

	Williams Partners	Exploration & Production	Other	Eliminations	Total
			(Millions)		
Three months ended June 30, 2010					
Segment revenues:					
External	$ 1,302	$ 734	$ 256	$	$ 2,292
Internal	65	176	6	(247)	
Total revenues	$ 1,367	$ 910	$ 262	$ (247)	$ 2,292
Segment profit	$ 346	$ 87	$ 79	$	$ 512
Less:					
Equity earnings	27	5	7		39
Income from investments			13		13
Segment operating income	$ 319	$ 82	$ 59	$	460
General corporate expenses					(45)
Total operating income					$ 415
Three months ended June 30, 2009*					
Segment revenues:					
External	$ 1,042	$ 703	$ 164	$	$ 1,909
Internal	39	106	6	(151)	
Total revenues	$ 1,081	$ 809	$ 170	$ (151)	$ 1,909
Segment profit	$ 285	$ 114	$ 16	$	$ 415
Less equity earnings	16	4	6		26
Segment operating income	$ 269	$ 110	$ 10	$	389
General corporate expenses					(38)
Total operating income					$ 351

	Williams Partners	Exploration & Production	Other	Eliminations	Total
			(Millions)		
Six months ended June 30, 2010					

Segment revenues:					
External	$ 2,693	$ 1,670	$ 525	$	$ 4,888
Internal	132	408	15	(555)	
Total revenues	$ 2,825	$ 2,078	$ 540	$ (555)	$ 4,888
Segment profit	$ 760	$ 249	$ 106	$	$ 1,115
Less:					
Equity earnings	53	10	16		79
Income from investments			13		13
Segment operating income	$ 707	$ 239	$ 77	$	1,023
General corporate expenses					(130)
Total operating income					$ 893
Six months ended June 30, 2009*					
Segment revenues:					
External	$ 1,966	$ 1,549	$ 316	$	$ 3,831
Internal	72	236	12	(320)	
Total revenues	$ 2,038	$ 1,785	$ 328	$ (320)	$ 3,831
Segment profit (loss)	$ 537	$ 190	$ (44)	$	$ 683
Less:					
Equity earnings	21	8	20		49
Loss from investments			(75)		(75)
Segment operating income	$ 516	$ 182	$ 11	$	709
General corporate expenses					(78)
Total operating income					$ 631

* Recast as discussed in Note 2.

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Notes (Continued)

Total segment revenues for Exploration & Production include $366 million, $276 million, $922 million, and $687 million of gas management revenues for the three and six months ended June 30, 2010 and 2009, 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.

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

	Total Assets	
	June 30, 2010	December 31, 2009
	(Millions)	
Williams Partners	$ 12,145	$ 11,981
Exploration & Production	10,400	10,575
Other	3,884	4,193
Eliminations	(1,482)	(1,469)
Total	$ 24,947	$ 25,280

Note 14. Subsequent Events

During the second quarter of 2010, Exploration & Production entered into an agreement to acquire additional leasehold acreage positions in the Marcellus Shale and a 5 percent overriding royalty interest associated with these acreage positions. These acquisitions closed in July for $597 million in cash, including closing adjustments.

In July 2010, we notified our partner in the Overland Pass Pipeline Company, LLC (OPPL) of our election to exercise our option to purchase an additional ownership interest, which will provide us a 50 percent ownership interest in OPPL. The option price is estimated to be approximately $425 million, which will reduce our available liquidity. Subject to government approvals, we expect to close the transaction within the third quarter of 2010.

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

Company Outlook

We believe we are well positioned to execute on our 2010 business plan and to capture attractive growth opportunities. While the economic environment in the latter half of 2009 and first quarter of 2010 improved compared to conditions earlier in 2009, this trend has moderated in the second quarter of 2010 as global economies continue to struggle. However, energy commodity price indicators, while recently lower, continue to reflect an expectation of growth and increasing demand. But given the potential volatility of these measures, it is reasonably possible that the economy could worsen and/or energy commodity prices could further decline, negatively impacting future operating results and increasing the risk of nonperformance of counterparties or impairments of goodwill and long-lived assets.

As a result of our 2010 restructuring (see Note 2 of Notes to Consolidated Financial Statements), we are better positioned to drive additional growth and pursue value-adding growth strategies. Our new structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions.

We continue to operate with a focus on EVA® 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 drilling;

- Retaining the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.

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

- Lower than anticipated energy commodity prices;

- 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 for which our aggregate insurance policy limit is $75 million in the event of a material loss.

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

Management s Discussion and Analysis (Continued)

revolving credit facilities. In addition, we utilize master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

Overview of Six Months Ended June 30, 2010

Income (loss) from continuing operations attributable to The Williams Companies, Inc., for the six months ended June 30, 2010, changed unfavorably by $133 million compared to the six months ended June 30, 2009.

This decrease is reflective 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. Partially offsetting the increased costs are:

- The improved energy commodity price environment in the first half of 2010 as compared to the first half of 2009;
- The absence of a $75 million pre-tax impairment charge in the first quarter of 2009 related to our Venezuelan equity investment in Accroven SRL (Accroven). (See Note 4 of Notes to Consolidated Financial Statements.)

See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for the six months ended June 30, 2010, increased $163 million compared to the six months ended June 30, 2009, primarily due to the increase in our operating income. *(*See Management s Discussion and Analysis of Financial Condition and Liquidity.)

Recent Events

In July 2010, we notified our partner in the Overland Pass Pipeline Company, LLC (OPPL) of our election to exercise our option to purchase an additional ownership interest, which will provide us a 50 percent ownership interest in OPPL, for approximately $425 million. (See Results of Operations Segments, Williams Partners.)

In May 2010, Exploration & Production announced a major acreage acquisition in the Marcellus Shale located in northeast Pennsylvania. In July 2010, the purchase was completed for $597 million, including closing adjustments. (See Results of Operations Segments, Exploration & Production.)

In February 2010, we completed a strategic restructuring that involved contributing certain of our wholly and partially owned subsidiaries to Williams Partners L.P. (WPZ), our consolidated master limited partnership, and restructuring our debt. (See Notes 2 and 9 of Notes to Consolidated Financial Statements and Management s Discussion and Analysis of Financial Condition and Liquidity.)

In April 2010, our Board of Directors approved a regular quarterly dividend of $0.125 per share, which reflects an increase of 14 percent compared to the $0.11 per share that we paid in each of the eight prior quarters.

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 May 26, 2010.

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Management s Discussion and Analysis (Continued)

Fair Value Measurements

Certain of our energy derivative assets and energy derivative liabilities trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. At June 30, 2010, 2 percent of our energy derivative assets and less than 1 percent of our energy derivative liabilities measured at fair value on a recurring basis are included in Level 3. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value for our energy derivative assets and energy derivative liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our energy derivative liabilities. The determination of the fair value of our energy derivative liabilities does not consider noncash collateral credit enhancements. For net derivative assets, we apply a credit spread, based on the credit rating of the counterparty, against the net derivative asset with that counterparty. For net derivative liabilities we apply our own credit rating. We derive the credit spreads by using the corporate industrial credit curves for each rating category and building a curve based on certain points in time for each rating category. The spread comes from the discount factor of the individual corporate curves versus the discount factor of the LIBOR curve. At June 30, 2010, the credit reserve is less than $1 million on our net derivative assets and $1 million on our net derivative liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

At June 30, 2010, 80 percent of the value of our derivatives portfolio expires in the next 12 months and more than 99 percent expires in the next 36 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

The instruments included in Level 3 at June 30, 2010, consist of natural gas liquids swaps and forward contracts for our midstream businesses, including those in our Williams Partners segment, as well as natural gas index transactions that are used to manage the physical requirements of our Exploration & Production segment. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices.

Exploration & Production has an unsecured credit agreement through December 2015 with certain banks that, so long as certain conditions are met, serves to reduce our usage of cash and other credit facilities for margin requirements related to instruments included in the facility.

For the six months ended June 30, 2009, we recognized impairments of certain assets that had been measured at fair value on a nonrecurring basis. These impairment measurements are included in Level 3 as they include significant unobservable inputs, such as our estimate of future cash flows and the probabilities of alternative scenarios. (See Note 10 of Notes to Consolidated Financial Statements.)

Critical Accounting Estimate

Impairment of Goodwill

As disclosed in our annual consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated May 26, 2010, we assess goodwill for impairment annually as of the end of the year. We perform interim assessments of goodwill if impairment triggering events or circumstances are present. One such triggering event is a significant decline in forward natural gas prices. Forward natural gas prices as of June 30, 2010 have declined compared to those used in our prior year-end analysis. We have evaluated the impact of this decline across all future production periods. Considering this and certain other factors, we determined that the impact was not significant enough to warrant a full impairment review. It is reasonably possible that we may be required to conduct an interim goodwill impairment evaluation during the remainder of 2010, which could result in a material impairment of goodwill.

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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, 2010, compared to the three and six months ended June 30, 2009. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended June 30,		$	%	Six months ended June 30,		$	%
	2010	2009	Change*	Change*	2010	2009	Change*	Change*
	(Millions)				(Millions)			
Revenues	$ 2,292	$ 1,909	+383	+20%	$ 4,888	$ 3,831	+1,057	+28%
Costs and expenses:								
Costs and operating expenses	1,723	1,392	-331	-24%	3,645	2,836	-809	-29%
Selling, general and administrative expenses	122	129	+7	+5%	233	254	+21	+8%
Other (income) expense net	(13)	(1)	+12	NM	(13)	32	+45	NM
General corporate expenses	45	38	-7	-18%	130	78	-52	-67%
Total costs and expenses	1,877	1,558			3,995	3,200		
Operating income	415	351			893	631		
Interest accrued net	(141)	(145)	+4	+3%	(288)	(287)	-1	0%
Investing income (loss)	55	24	+31	+129%	94	(37)	+131	NM
Early debt retirement costs				0%	(606)		-606	NM
Other income (expense) net	(1)	1	-2	NM	(8)	(1)	-7	NM
Income from continuing operations before income taxes	328	231			85	306		
Provision for income taxes	104	80	-24	-30%	9	136	+127	+93%
Income from continuing operations	224	151			76	170		
Income (loss) from discontinued operations	(2)	18	-20	NM		(225)	+225	+100%
Net Income (loss)	222	169			76	(55)		
Less: Net income (loss) attributable to noncontrolling interests	37	27	-10	-37%	84	(25)	-109	NM
	$ 185	$ 142			$ (8)	$ (30)		

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, 2010 vs. three months ended June 30, 2009

The increase in *revenues* is primarily due to higher natural gas liquids (NGL) and crude oil marketing revenues and higher NGL production revenues at Williams Partners, reflecting higher average NGL and crude prices. Additionally, Exploration & Production gas management and production revenues increased reflecting an increase in average natural gas prices, partially offset by a decrease in production volumes sold. NGL and olefin production revenues at Other also increased due to higher average per-unit prices.

The increase in *costs and operating expenses* is primarily due to increased NGL and crude oil marketing purchases and NGL production costs at Williams Partners, reflecting higher average NGL, crude and natural gas prices. Exploration & Production costs increased primarily due to increased average natural gas prices associated with gas management activities. Additionally, NGL and olefin production costs at Other increased due to higher average per-unit feedstock costs.

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.

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Management s Discussion and Analysis (Continued)

The increase in *operating income* generally reflects an improved energy commodity price environment in the second quarter of 2010 compared to the second quarter of 2009.

The favorable change in *investing income (loss)* is primarily due to a $13 million pre-tax gain on the sale of our 50 percent interest in Accroven in the second quarter of 2010 (see Note 4 of Notes to Consolidated Financial Statements) and a $13 million increase in equity earnings, primarily at Williams Partners.

Provision for income taxes increased primarily due to higher pre-tax income. 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 (loss) attributable to noncontrolling interests* reflects higher operating results, primarily at Williams Partners, due to an improved energy commodity price environment in 2010 compared to 2009.

Six months ended June 30, 2010 vs. six months ended June 30, 2009

The increase in *revenues* is primarily due to higher NGL and crude oil marketing revenues and higher NGL production revenues at Williams Partners, reflecting higher average NGL and crude prices. Additionally, Exploration & Production gas management and production revenues increased reflecting an increase in average natural gas prices, partially offset by a decrease in production volumes sold. NGL and olefin production revenues at Other also increased due to higher average per-unit prices.

The increase in *costs and operating expenses* is primarily due to increased NGL and crude oil marketing purchases and NGL production costs at Williams Partners, reflecting higher average NGL, crude and natural gas prices. Exploration & Production costs increased primarily due to increased average natural gas prices associated with gas management activities. Additionally, NGL and olefin production costs at Other increased due to higher average per-unit feedstock costs.

Selling, general and administrative expenses decreased primarily due to lower pension and certain other employee-related expenses at Williams Partners.

Other (income) expense net within *operating income* in 2010 includes $11 million of involuntary conversion gains at Williams Partners, as previously discussed.

Other (income) expense net within *operating income* in 2009 includes $32 million of penalties from the early termination of certain drilling rig contracts at Exploration & Production.

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

The increase in *operating income* generally reflects an improved energy commodity price environment in 2010 compared to 2009 and the absence of $32 million of penalties in 2009 from the early termination of certain drilling rig contracts at Exploration & Production, partially offset by $41 million of transaction costs associated with our 2010 restructuring transaction.

The favorable change in *investing income (loss)* is primarily due to the absence of both 2009 impairment charges of $75 million related to our Accroven equity investment at Other and $11 million related to a cost-based investment at Exploration & Production, a $30 million increase in equity earnings, primarily at Williams Partners, and a $13 million pre-tax gain on the sale of our 50 percent interest in Accroven in the second quarter of 2010.

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

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Management s Discussion and Analysis (Continued)

Provision for income taxes decreased primarily due to lower pre-tax income. 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 (loss) attributable to noncontrolling interests* reflects higher operating results, primarily at Williams Partners, due to an improved energy commodity price environment in 2010 compared to 2009 and the impact of the first-quarter 2009 impairments and related charges associated with our discontinued Venezuela operations.

Management s Discussion and Analysis (Continued)

Results of Operations Segments

Williams Partners

Our Williams Partners segment reflects the results of operations of WPZ, our consolidated master limited partnership. WPZ 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. Upon completing our strategic restructuring, we now own approximately 84 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.

Overview of Six Months Ended June 30, 2010

Significant events during 2010 include the following:

Perdido Norte

Our Perdido Norte project, in the western deepwater of the Gulf of Mexico, began start-up of operations late in the first quarter of 2010. The project includes a 200 million cubic feet per day (MMcf/d) expansion of our onshore Markham gas processing facility and a total of 184 miles of deepwater oil and gas lines that expand the scale of our existing infrastructure. Shortly after an initial startup, production was suspended during the second quarter to address facility issues. Currently our facilities are fully commissioned and ready to receive production, which we expect to begin receiving in the third quarter of 2010.

Impact of Gulf Oil Spill

Our transportation and processing assets in the Gulf of Mexico have not been significantly impacted by the Deepwater Horizon oil spill. Operations are normal at all facilities with the exception of increased air quality monitoring at our facilities in the eastern Gulf of Mexico. We have not experienced any operational or logistical issues that would hinder the safety of our employees or facilities. If exploration in the Gulf of Mexico is restricted, our expected future volumes will be reduced for the remainder of 2010. While it is too early to predict, if impacted producers reduce their offshore or onshore capital growth plans, our expected future volumes will be reduced more significantly in the long term. While we continue to carefully monitor the events and business environment in the Gulf of Mexico for potential negative impacts, we also continue to pursue major expansion and growth opportunities in the Gulf of Mexico, including the possible construction of deepwater pipelines and our deepwater floating production system referred to as Gulfstar.

Overland Pass Pipeline

In July 2010, we notified our partner in OPPL of our election to exercise our option to purchase an additional ownership interest, which will provide us a 50 percent ownership interest in OPPL. The option price is estimated to be approximately $425 million. Subject to government approvals, we expect to close the transaction within the third quarter with an effective acquisition date of June 30, 2010. In 2006, we entered into an agreement to develop new pipeline capacity for transporting NGLs from production areas in the Rocky Mountain area to central Kansas. Our partner reimbursed us for the development costs we had incurred for the proposed pipeline and acquired 99 percent of the pipeline. We retained a 1 percent interest and the option to increase our ownership to 50 percent within two years of the pipeline becoming operational in November of 2008. As long as we retain a 50 percent ownership interest in OPPL, we have the right to become operator upon providing notice. OPPL 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-Joules Basins in Colorado, respectively. Our equity NGL volumes from our

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Management s Discussion and Analysis (Continued)

two Wyoming plants and our Willow Creek facility in Colorado are dedicated for transport on OPPL under a long-term shipping agreement.

Volatile commodity prices

Average per-unit NGL margins in the six months ending June 30, 2010 are significantly higher than the same period of 2009, benefiting from a period of increasing average NGL prices while abundant natural gas supplies limited the increase in natural gas prices. Benefits from favorable natural gas price differentials in the Rocky Mountain area have narrowed since the second quarter of 2009 such that our realized per-unit margins are only slightly greater than that of the industry benchmarks for natural gas processed in the Henry Hub area and for liquids fractionated and sold at Mont Belvieu, Texas.

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.

Williams Pipeline Partners L.P.

As of June 30, 2010, WPZ owns approximately 47.7 percent of the interests in Williams Pipeline Partners L.P. (WMZ), including the interests of the general partner, which is wholly owned by WPZ, and incentive distribution rights. WPZ consolidates WMZ due to its control through the general partner. On May 24, 2010, WPZ and WMZ entered into a merger agreement providing for the merger of WMZ into WPZ. (See Note 2 of Notes to Consolidated Financial Statements.)

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Management s Discussion and Analysis (Continued)

Mobile Bay South expansion project

In May 2010, a compression facility in Alabama allowing natural gas pipeline transportation service to various southbound delivery points was placed into service. The cost of the project is estimated to be $34 million and increased capacity by 253 thousand dekatherms per day (Mdt/d).

Outlook for the Remainder of 2010

The following factors could impact our business in 2010.

Commodity price changes

While our per-unit NGL margins have declined from the first to the second quarter of 2010, we expect our average per-unit NGL margins in 2010 to be higher than our average per-unit margins in 2009 and 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 and difficult to predict. NGL margins are highly dependent upon continued demand within the global economy. Forecasted domestic and global demand for polyethylene, or plastics, has been impacted by the weakness in the global economy. In addition, projected new third party international ethylene production capacity may lower future demand for domestic ethylene. 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 2010. The combined impact of these energy commodity derivatives will provide a margin on the hedged volumes of $117 million.

Gathering, processing, and NGL sales volumes

The growth of natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities. While it is too early to predict the ultimate impact of the Gulf oil spill, our future volumes will likely be reduced for the remainder of 2010 if exploration in the Gulf of Mexico is restricted or if producers reduce their offshore or onshore capital growth plans. Our customers are generally large producers, and we have not experienced and do not anticipate an overall significant decline in volumes due to reduced drilling activity.

In our onshore businesses, we expect higher fee revenues, NGL volumes, depreciation expense and operating expenses in 2010 compared to 2009 as our Willow Creek facility moves into a full year of operation, and our expansion at Echo Springs is completed late in 2010.

We expect fee revenues, NGL volumes, depreciation expense, and operating expenses in our Gulf Coast businesses to increase from 2009 levels with our Perdido Norte expansion operations, which we expect to contribute to segment profit beginning in the third quarter of 2010. Increased volumes from our Perdido Norte expansion are expected to be partially offset by lower volumes in other Gulf Coast areas due to natural declines.

Expansion projects

We expect to spend $1,095 million to $1,325 million in 2010 on capital projects and additional investments in partially owned equity investments, of which $891 million to $1,121 million remains to be spent. The ongoing major expansion projects include:

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Management s Discussion and Analysis (Continued)

85 North

An expansion of our existing natural gas transmission system from Alabama to various delivery points as far north as North Carolina. The cost of the project is estimated to be $241 million. Phase I service was placed into service in July 2010 and increased capacity by 90 Mdt/d. Phase II service is anticipated to begin in May 2011 and will increase capacity by 218 Mdt/d.

Sundance Trail

A 16-mile, 30-inch natural gas pipeline between our existing compressor stations in Wyoming. The project also includes an upgrade to our existing compressor station and is estimated to cost $60 million. The estimated in-service date is November 2010 and will increase capacity by 150 Mdt/d.

Echo Springs

Additional processing and NGL production capacities at our Echo Springs facility and related gathering system expansions in the Wamsutter area of Wyoming, which we expect to be in service in the fourth quarter of 2010.

Mobile Bay South II

Additional compression facilities and modifications to existing 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 is scheduled to begin in August 2010 and is estimated to cost $36 million. The estimated project in-service date is May 2011 and will increase capacity by 380 Mdt/d.

Marcellus Shale

A 28-mile natural gas gathering pipeline in the Marcellus Shale region, which we will construct and operate in conjunction with a long-term agreement with a major producer. Construction on the 20-inch pipeline, which will deliver gas into the Transco pipeline, is expected to begin in the first quarter of 2011 and be completed during 2011.

Laurel Mountain

Additional capital to be invested within our Laurel Mountain Midstream, LLC (Laurel Mountain) equity investment to grow the existing gathering infrastructure with additional pipeline miles, compression and well-connects in 2010 and beyond. Laurel Mountain will also benefit from a recent joint venture transaction between its anchor customer and a third-party drilling partner, which we expect to provide the funding to accelerate the customer s drilling plans and grow their leasehold position in the Marcellus Shale region dedicated to Laurel Mountain gathering services.

Parachute

We intend to pursue construction of a 450 MMcf/d cryogenic gas processing facility to be located at Exploration & Production s Parachute plant complex capable of recovering up to 25 Mbbls/d of NGLs. Production from Exploration & Production in the Piceance valley and highlands currently exceeds the processing capacity at the Willow Creek plant. The new Parachute plant is expected to be in service in 2013 and will process Exploration & Production s equity production from its existing treatment facilities. This proposed project is subject to certain final approvals.

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 as early as 2010.

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Management s Discussion and Analysis (Continued)

Period-Over-Period Operating Results

	Three months ended June 30,		Six months ended June 30,	
	2010	**2009**	**2010**	**2009**
	(Millions)		**(Millions)**	
Segment revenues	$ 1,367	$ 1,081	$ 2,825	$ 2,038
Segment profit	$ 346	$ 285	$ 760	$ 537

Three months ended June 30, 2010 vs. three months ended June 30, 2009

The increase in *segment revenues* is largely due to:

A $213 million increase in marketing revenues primarily due to higher average NGL and crude prices. These changes are more than offset by similar changes in marketing purchases.

A $100 million increase in NGL production revenues reflecting an increase of $91 million associated with a 56 percent increase in average NGL per-unit sales prices.

An $8 million increase in fee revenues primarily due to new fees for processing Exploration & Production s natural gas production at Willow Creek, partially offset by reduced fees from lower deepwater gathering and transportation volumes.

These increases are partially offset by a $38 million decrease in revenues from lower natural gas pipeline transportation imbalance settlements in 2010 compared to 2009 (offset in *costs and operating expenses*).

Segment costs and expenses increased $236 million primarily as a result of:

A $232 million increase in marketing purchases primarily due to higher average NGL and crude prices. These changes more than offset similar changes in marketing revenues.

A $37 million increase in NGL production costs due primarily to a 50 percent increase in average natural gas prices.

These increases are partially offset by:

A $38 million decrease in costs associated with lower natural gas pipeline transportation imbalance settlements in 2010 compared to 2009 (offset in *segment revenues*).

An $11 million favorable change related to involuntary conversion gains due to insurance recoveries in excess of the carrying value of our Ignacio plant, which was damaged by a fire in 2007, and Gulf assets which were damaged by Hurricane Ike in 2008.

The increase in William Partners *segment profit* includes $63 million of higher NGL production margins reflecting an improved energy commodity price environment in 2010 compared to 2009, $11 million of involuntary conversion gains, and $11 million of higher equity earnings related to a $5 million increase from Aux Sable Liquid Products LP (Aux Sable) primarily due to higher processing margins and a $5 million increase from Discovery Producer Services LLC (Discovery) primarily due to higher processing margins and new volumes from an expansion completed in 2009. Partially offsetting these increases is a $19 million decrease in NGL and crude marketing margins primarily due to unfavorable changes in pricing while product was in transit in 2010 as compared to favorable changes in pricing while product was in transit in 2009.

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Management s Discussion and Analysis (Continued)

Six months ended June 30, 2010 vs. six months ended June 30, 2009

The increase in *segment revenues* is largely due to:

A $506 million increase in marketing revenues primarily due to higher average NGL and crude prices. These changes are more than offset by similar changes in marketing purchases.

A $288 million increase in NGL production revenues reflecting an increase of $255 million associated with a 76 percent increase in average NGL per-unit sales prices and an increase of $33 million associated with a 12 percent increase in ethane volumes sold and a 3 percent increase in non-ethane volumes sold.

A $15 million increase in fee revenues primarily due to new fees for processing Exploration & Production s natural gas production at Willow Creek, partially offset by reduced fees from lower deepwater gathering and transportation volumes.

These increases are partially offset by a $32 million decrease in revenues from lower natural gas pipeline transportation imbalance settlements in 2010 compared to 2009 (offset in *costs and operating expenses*) and an $18 million decrease in natural gas pipeline transportation other service revenues due to reduced customer usage of our temporary natural gas loan and storage services.

Segment costs and expenses increased $596 million primarily as a result of:

A $527 million increase in marketing purchases primarily due to higher average NGL and crude prices. These changes more than offset similar changes in marketing revenues.

A $90 million increase in NGL production costs reflecting an increase of $77 million associated with a 44 percent increase in average natural gas prices and an increase of $13 million associated with an 8 percent increase in gas volumes for BTU replacement cost and plant fuel.

These increases are partially offset by:

A $32 million decrease in costs associated with lower natural gas pipeline transportation imbalance settlements in 2010 compared to 2009 (offset in *segment revenues*).

A $12 million favorable change related to involuntary conversion gains due to insurance recoveries in excess of the carrying value of our Ignacio plant, which was damaged by a fire in 2007, and Gulf assets which were damaged by Hurricane Ike in 2008.

A $9 million decrease in *selling, general and administrative expenses* at Gas Pipeline, primarily due to lower employee-related expenses including pension and other postretirement benefits.

The increase in William Partners *segment profit* includes $198 million of higher NGL production margins reflecting an improved energy commodity price environment in 2010 compared to 2009, $32 million of higher equity earnings related to a $19 million increase from Discovery primarily due to recovery from the impact of the 2008 hurricanes, new volumes from an expansion completed in 2009 and higher processing margins and a $10 million increase from Aux Sable primarily due to higher processing margins, a $15 million increase in fee revenues, and a $12 million favorable change in involuntary conversion gains. Partially offsetting these increases are a $21 million decrease in NGL and crude marketing margins primarily due to unfavorable changes in pricing while product was in transit in 2010 as compared to favorable changes in pricing while product was in transit in 2009 and an $18 million decrease in natural gas pipeline transportation other service revenues.

Management s Discussion and Analysis (Continued)

Exploration & Production

Exploration & Production includes the natural gas development, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States, development activities in the Eastern portion of the United States and oil and natural gas interests in South America. The gas management activities include procuring fuel and shrink gas for our midstream businesses and providing marketing services to third parties, such as producers. Additionally, gas management activities include the managing of various natural gas related contracts such as transportation, storage and related hedges not utilized for our own production.

Overview of Six Months Ended June 30, 2010

Domestic production revenues and profit for the first six months of 2010 were higher than the first six months of 2009 primarily due to higher net realized average prices on our natural gas production, partially offset by lower production volumes. Additionally, the first six months of 2009 included expense of $32 million associated with contractual penalties from the early termination of drilling rig contracts. Highlights of the comparative periods, primarily related to our production activities, include:

	For the six months ended June 30,		
	2010	2009	% Change
Average daily domestic production (MMcfe)(1)	1,106	1,202	-8%
Average daily total production (MMcfe)	1,162	1,255	-7%
Domestic production net realized average price ($/Mcfe)(2)	$ 4.68	$ 4.08	+15%
Capital expenditures ($ millions)	$ 550	$ 519	+6%
Domestic production revenues ($ millions)	$1,081	$1,009	+7%
Segment revenues ($ millions)	$2,078	$1,785	+16%
Segment profit ($ millions)	$ 249	$ 190	+31%

(1) MMcfe is equal to one million cubic feet of gas equivalent.

(2) Mcfe is equal to one thousand cubic feet of gas equivalent. Net realized average prices include market prices, net of fuel and shrink and hedge gains and losses, less gathering and transportation expenses. The realized hedge gain per Mcfe was $0.63 and $1.51 for the six

months ended
June 30, 2010
and 2009,
respectively.

During the first quarter of 2010, we spent a total of $60 million to acquire additional unproved leasehold acreage positions in the Appalachian basin.

During the second quarter of 2010, we entered into an agreement to acquire additional leasehold acreage positions and a 5 percent overriding royalty interest associated with these acreage positions. These acquisitions nearly double our acreage holdings in the Marcellus Shale and closed in July for $597 million, including closing adjustments.

Outlook for the Remainder of 2010

Our expectations and objectives for the remainder of the year include:

- Continuation of our development drilling program in the Piceance, Powder River, Fort Worth, San Juan and Appalachian basins. Our total remaining capital expenditures for 2010 are projected to be between $1.35 billion and $1.55 billion, including the recently completed leasehold acquisition in the Marcellus Shale.

- Annual average daily domestic production level consistent with 2009 volumes, with fourth quarter 2010 volumes likely to be higher than the prior year comparable period.

Risks to achieving our expectations and objectives include unfavorable natural gas market price movements which are impacted by numerous factors, including weather conditions, domestic natural gas production levels and demand, and a slower recovery in the global economy than expected. A significant decline in natural gas prices would also impact these expectations for the remainder of the year, although the impact would be somewhat 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.

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Management s Discussion and Analysis (Continued)

Commodity Price Risk Strategy

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative contracts for a portion of our future production. For the remainder of 2010, we have the following contracts for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

		Remainder of 2010	
		Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Collar agreements	Rockies	100	$6.53 - $8.94
Collar agreements	San Juan	230	$5.75 - $7.84
Collar agreements	Mid-Continent	105	$5.37 - $7.41
Collar agreements	Southern California	45	$4.80 - $6.43
Collar agreements	Other	30	$5.66 - $6.89
NYMEX and basis fixed-price		120	$4.38

The following is a summary of our agreements and contracts for daily production for the three and six months ended June 30, 2010 and 2009:

		2010		2009	
		Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Second Quarter:					
Collars	Rockies	100	$6.53 - $8.94	150	$6.11 - $9.04
Collars	San Juan	230	$5.75 - $7.84	245	$6.58 - $9.62
Collars	Mid-Continent	105	$5.37 - $7.41	95	$7.08 - $9.73
Collars	Southern California	45	$4.80 - $6.43		
Collars	Other	30	$5.66 - $6.89		
NYMEX and basis fixed-price		120	$4.39	106	$3.61
Year-to-Date:					
Collars	Rockies	100	$6.53 - $8.94	150	$6.11 - $9.04
Collars	San Juan	235	$5.74 - $7.81	245	$6.58 - $9.62
Collars	Mid-Continent	105	$5.37 - $7.41	95	$7.08 - $9.73
Collars	Southern California	45	$4.80 - $6.43		
Collars	Other	25	$5.61 - $6.85		
NYMEX and basis fixed-price		120	$4.41	107	$3.59

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 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.

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Management s Discussion and Analysis (Continued)

Period-Over-Period Operating Results

	Three months ended June 30,		Six months ended June 30,	
	2010	**2009**	**2010**	**2009**
	(Millions)		**(Millions)**	
Segment revenues:				
Domestic production revenues	$ 510	$ 486	$ 1,081	$ 1,009
Gas management revenues	366	276	922	687
Net forward unrealized mark-to-market gains (losses) and ineffectiveness		(1)	9	9
Other revenues	34	48	66	80
Total segment revenues	$ 910	$ 809	$ 2,078	$ 1,785
Segment profit	$ 87	$ 114	$ 249	$ 190

Three months ended June 30, 2010 vs. three months ended June 30, 2009

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

The increase in domestic production revenues reflects an increase of $53 million associated with a 12 percent increase in realized average prices including the effect of hedges, partially offset by a decrease of $29 million associated with a 6 percent decrease in production volumes sold. Production revenues in 2010 and 2009 include approximately $47 million and $15 million, respectively, related to natural gas liquids and approximately $14 million and $8 million, respectively, related to condensate.

The increase in gas management revenues is primarily due to an increase in physical natural gas revenue as a result of a 32 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 offset by a similar increase in *segment costs and expenses.*

Partially offsetting the increased revenues is a $14 million decrease in other revenue, primarily due to the absence in 2010 of the 2009 recovery of certain royalty overpayments from prior years.

Total *segment costs and expenses* increased $129 million, primarily due to the following:

$98 million increase in gas management expenses, primarily due to a 33 percent increase in average prices on physical natural gas purchases. This increase is primarily related to the gas purchases associated with our previously discussed transportation and storage contracts and is substantially offset by a similar increase in *segment revenues*. Gas management expenses in 2010 and 2009 also include $12 million and $5 million, respectively, related to costs for unutilized pipeline capacity.

$27 million higher operating taxes primarily due to higher average market prices (excluding the impact of hedges) and the absence of certain favorable adjustments recorded in 2009.

$8 million higher gathering, processing, and transportation expenses primarily as a result of the processing of natural gas liquids at Williams Partners Willow Creek plant, which began processing in August 2009.

Partially offsetting the increased costs is $11 million lower exploratory expense in 2010, primarily related to lower seismic costs.

The $27 million decrease in *segment profit* is primarily due to the increase in *segment costs and expenses* and the absence in 2010 of the 2009 recovery of certain royalty overpayments from prior years, partially offset by a 12 percent increase in realized average domestic prices.

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Management s Discussion and Analysis (Continued)

Six months ended June 30, 2010 vs. six months ended June 30, 2009

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

The increase in domestic production revenues reflects an increase of $153 million associated with a 16 percent increase in realized average prices including the effect of hedges, partially offset by a decrease of $81 million associated with an 8 percent decrease in production volumes sold. Production revenues in 2010 and 2009 include approximately $93 million and $23 million, respectively, related to natural gas liquids and approximately $25 million and $15 million, respectively, related to condensate.

The increase in gas management revenues is primarily due to an increase in physical natural gas revenue as a result of a 30 percent increase in average prices on physical natural gas sales and a 3 percent increase in natural gas sales volumes. This is primarily related to gas sales associated with our transportation and storage contracts and is offset by a similar increase in *segment costs and expenses.*

Partially offsetting the increased revenues is a $14 million decrease in other revenue, primarily due to the absence in 2010 of the 2009 recovery of certain royalty overpayments from prior years.

Total *segment costs and expenses* increased $236 million, primarily due to the following:

$234 million increase in gas management expenses, primarily due to a 28 percent increase in average prices on physical natural gas purchases and a 3 percent increase in natural gas purchase volumes. This increase is primarily related to the gas purchases associated with our previously discussed transportation and storage contracts and is substantially offset by a similar increase in *segment revenues*. Gas management expenses in 2010 and 2009 include $25 million and $9 million, respectively, related to charges for unutilized pipeline capacity. In addition, a $7 million unfavorable adjustment was made in 2009 to the carrying value of natural gas in storage reflecting a decline in the price of natural gas in 2009.

$36 million higher operating taxes primarily due to higher average market prices, excluding the impact of hedges.

$23 million higher gathering, processing, and transportation expenses primarily as a result of the processing of natural gas liquids at Williams Partners Willow Creek plant, which began processing in August 2009.

Partially offsetting the increased costs are decreases due to the following:

The absence of $32 million of expenses in 2009 related to penalties from the early release of drilling rigs as previously discussed.

$19 million lower exploratory expense in 2010, primarily related to lower seismic costs.

The $59 million increase in *segment profit* is primarily due to the 16 percent increase in realized average domestic prices on production and the other previously discussed changes in *segment revenues* and *segment costs and expenses.*

Other

Overview of Six Months Ended June 30, 2010

Our Other segment primarily includes our Canadian midstream and domestic olefins operations and a 25.5 percent interest in Gulfstream, as well as corporate operations. *Segment profit (loss)* for the six months ended June 30, 2010 has improved compared to the prior year primarily due to the absence of a $75 million total impairment of our Venezuelan investment in Accroven in 2009, $73 million higher NGL and olefins production margins resulting from sharply higher average per-unit margins and a $13 million gain for cash received in June 2010 for the sale of our investment in Accroven.

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Management s Discussion and Analysis (Continued)

Outlook for the Remainder of 2010

The following factors could impact our business in 2010.

Commodity price changes

Margins in our Canadian midstream and domestic olefins business are highly dependent upon continued demand within the global economy. Forecasted domestic and global demand for polyethylene, or plastics, has been impacted by the weakness in the global economy. In addition, projected new third-party international ethylene production capacity may lower future demand for domestic ethylene. 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 because of our NGL-based olefins production.

We anticipate average per-unit margins for 2010 will increase over 2009 levels, benefiting from the dynamics discussed above.

Allocation of capital to projects

We expect to spend $150 million to $200 million in 2010 on capital projects. The major expansion projects include:

A 12-inch diameter pipeline in Canada, which will transport recovered natural gas liquids 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. We expect to begin construction in 2010 and anticipate an in-service date in 2012.

New splitter and hydro-treating facilities that will upgrade the value of one of the products produced at the fractionators near Edmonton, Alberta. The new facilities, which we expect to complete in the third quarter of 2010, will take the butylene/butane mix product currently produced and further fractionate the mix product into two higher value products that are in greater demand in the market place.

Sale of Accroven

In June 2010, we sold our 50 percent interest in Accroven to Petróleos de Venezuela S.A. (PDVSA) for $107 million. Of this amount, $13 million was received in cash at closing. Another $30 million is due on July 31, 2010, and the remainder is due in six quarterly payments beginning October 31, 2010. Considering the deteriorating circumstances in Venezuela, we fully impaired our $75 million investment in Accroven in 2009. We are currently recognizing the resulting gain as cash is received. In connection with this sale, PDVSA also repaid Accroven s outstanding debt balances directly to the lenders.

Period-Over-Period Operating Results

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
	(Millions)		(Millions)	
Segment revenues	$ 262	$ 170	$ 540	$ 328
Segment profit (loss)	$ 79	$ 16	$ 106	$ (44)

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Management s Discussion and Analysis (Continued)

Three months ended June 30, 2010 vs. three months ended June 30, 2009

Segment revenues increased primarily due to $97 million higher NGL and olefins production revenues associated with significantly higher average per-unit prices and $9 million higher marketing revenues resulting from general increases in energy commodity prices on higher volumes. These increases were partially offset by a $13 million decrease primarily due to 13 percent lower ethylene sales volumes and 17 percent lower propylene volumes available for processing at the propylene splitter. The higher marketing revenues were more than offset by similar changes in marketing purchases described below.

Segment costs and expenses increased $43 million primarily due to $42 million higher NGL and olefins production product costs resulting from higher average per-unit feedstock costs and $12 million increased marketing purchases resulting from general increases in energy commodity prices on higher volumes. These increases were partially offset by $10 million related primarily to the reduced ethylene and propylene sales volumes described above and a $6 million customer settlement received in 2010. The increased marketing purchases more than offset similar changes in marketing revenues.

The favorable change in *segment profit (loss)* is primarily due to $52 million higher NGL and olefins production margins resulting from sharply higher per-unit margins on lower olefin volumes, a $13 million gain on the sale of Accroven and a $6 million customer settlement received in 2010.

Six months ended June 30, 2010 vs. six months ended June 30, 2009

Segment revenues increased primarily due to $220 million higher NGL and olefins production revenues resulting from significantly higher average per-unit prices and $32 million higher marketing revenues due to general increases in energy commodity prices on higher volumes. These increases were partially offset by a $39 million decrease due primarily to 30 percent lower propylene volumes available for processing at our propylene splitter, 19 percent lower volumes at our Canadian facility resulting from operational issues at a third-party facility which provides our feedstock and 6 percent lower ethylene sales volumes. The higher marketing revenues were more than offset by similar changes in marketing purchases described below.

Segment costs and expenses increased $146 million primarily as a result of $138 million higher NGL and olefins production product costs resulting from higher average per-unit feedstock costs and $35 million increased marketing purchases due to general increases in energy commodity prices on higher volumes. These increases were partially offset by $30 million of lower product costs as a result of the lower sales volumes described above and a $6 million customer settlement received in 2010. The increased marketing purchases more than offset similar changes in marketing revenues.

The favorable change in *segment profit (loss)* is primarily due to the absence of a $75 million impairment of our investment in Accroven in the first quarter of 2009, $73 million higher NGL and olefins production margins resulting from sharply higher average per-unit margins on lower volumes, a $13 million gain on the sale of Accroven and a $6 million customer settlement received in second-quarter 2010.

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Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition and Liquidity

Strategic Restructuring

On February 17, 2010, we completed a strategic restructuring, which involved contributing a substantial majority of our domestic midstream and gas pipeline businesses, including our limited and general partner interests in WMZ, into WPZ. We currently own approximately 84 percent of WPZ. We intend to hold our limited partner and general partner units for the long-term. As consideration for the asset contributions, we received proceeds from WPZ s debt issuance of approximately $3.5 billion, less WPZ s transaction fees and expenses and other post-closing adjustments, as well as 203 million WPZ Class C units, which received a prorated initial distribution and were then converted to regular common units on May 10, 2010. We also maintained our 2 percent general partner interest. WPZ assumed approximately $2 billion of existing debt associated with the gas pipeline assets. In connection with the restructuring, we retired $3 billion of our debt and paid $574 million in related premiums. These amounts, as well as other transaction costs, were primarily funded with the cash consideration we received from WPZ. As a result of our restructuring, we are better positioned to drive additional growth and pursue value-adding growth strategies. Our new structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions.

Outlook

For 2010, we expect operating results and cash flows to improve from 2009 levels due to the overall impact of expected higher energy commodity prices. Lower-than-expected energy commodity prices would be somewhat mitigated by certain of our cash flow streams that are substantially insulated from 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 debt payments while maintaining a sufficient level of liquidity. In particular, we note the following assumptions for the year:

- We expect to maintain consolidated liquidity of at least $1 billion from *cash and cash equivalents* and unused revolving credit facilities.
- 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 $2.275 billion and $2.8 billion in 2010.
- We expect capital and investment expenditures to total between $3.475 billion and $3.975 billion in 2010, including Exploration & Production s recently completed acquisition in the Marcellus Shale and our announced intention to increase our ownership in OPPL. Of this total, a significant portion of Williams Partners expected expenditures of $1.41 billion to $1.68 billion are considered nondiscretionary to meet legal, regulatory, and/or contractual requirements or to fund committed growth projects. Exploration & Production s expected expenditures of $1.9 billion to $2.1 billion are considered primarily discretionary.

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

- Lower than expected levels of cash flow from operations;

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

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Management s Discussion and Analysis (Continued)

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2010. Our internal and external sources of consolidated liquidity include cash generated from our operations, cash and cash equivalents on hand, and our credit facilities. Additional sources of liquidity, if needed, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. These sources are available to us at the parent level and are expected to be available to certain of our subsidiaries, particularly equity and debt issuances from WPZ. WPZ is expected to be 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 only through distributions in accordance with the partnership agreement. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

Available Liquidity	**Credit Facilities Expiration**	**WPZ**	**June 30, 2010 WMB (Millions)**	**Total**
Cash and cash equivalents		$ 218	$ 1,383(1)	$ 1,601
Available capacity under our unsecured revolving and letter of credit facilities:				
$700 million facilities (2)	October 2010		567	567
$900 million facility (3)	May 2012		873	873
Available capacity under Williams Partners L.P. s $1.75 billion senior unsecured credit facility (3)	February 2013	1,750		1,750
		$ 1,968	$ 2,823	$ 4,791

(1) *Cash and cash equivalents* includes $31 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 $457 million of *cash and cash equivalents* that is being utilized by certain subsidiary and international operations. The remainder of our *cash and cash equivalents* is

primarily held in government-backed instruments.

(2) These facilities were originated primarily in support of our former power business. At June 30, 2010, we are in compliance with the financial covenants associated with these credit facilities.

(3) At June 30, 2010, we are in compliance with the financial covenants associated with these credit facilities. In connection with our previously discussed restructuring transactions, WPZ, Northwest Pipeline, and Transco entered into a new $1.75 billion, three-year, senior unsecured revolving credit facility, which replaced WPZ s unsecured $450 million credit facility (which was comprised of a $250 million term loan and a $200 million revolving credit facility). At the closing, WPZ utilized $250 million of the new credit facility to repay the outstanding term

loan. As of June 30, 2010, no loans are outstanding under the new credit facility. This facility is available to WPZ to the extent not otherwise utilized by Transco and Northwest Pipeline, and may, under certain conditions, be increased by up to an additional $250 million. Transco and Northwest Pipeline are co-borrowers and each have access to borrow up to $400 million under the new credit facility to the extent not otherwise utilized by WPZ. As WPZ will be funding projects for its midstream and gas pipeline businesses, we reduced our existing $1.5 billion unsecured credit facility that expires May 2012 to $900 million and removed Transco and Northwest Pipeline as borrowers. See the financial covenants of the new facility in Note 9 of Notes to Consolidated Financial Statements.

Subsequent to June 30, 2010, our cash was reduced by approximately $597 million, including closing adjustments, related to Exploration & Production s acquisition in the Marcellus Shale. (See Results of Operations Segments, Exploration & Production.) We also expect our available liquidity will be reduced by

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Management s Discussion and Analysis (Continued)

approximately $425 million in the third quarter related to WPZ s acquisition of an increased interest in OPPL. (See Results of Operations Segments, Williams Partners.)

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. In July 2010, the agreement term was extended from December 2013 to December 2015.

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	Stable	Stable
Fitch Ratings (3)		
Senior Unsecured Debt Rating	BBB-	BBB-
Outlook	Stable	Stable

(1) A rating of BBB or above indicates an investment grade rating. A rating below BBB indicates that the security has significant speculative characteristics. A BB rating indicates that Standard & Poor s believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse

business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor s may modify its ratings with a + or a - sign to show the obligor s relative standing within a major rating category.

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

(3) A rating of BBB or above indicates an investment grade rating. A

rating below BBB is considered speculative grade. Fitch may add a + or a - sign to show the obligor s relative standing within a major rating category.

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, 2010, we estimate that a downgrade to a rating below investment grade for WMB or WPZ would require us to post up to $541 million or $75 million, respectively, in additional collateral with third parties.

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Management s Discussion and Analysis (Continued)

Sources (Uses) of Cash

	Six months ended June 30, 2010	2009
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 1,297	$ 1,134
Financing activities	(630)	343
Investing activities	(933)	(1,063)
Increase (decrease) in cash and cash equivalents	$ (266)	$ 414

Operating activities

Our *net cash provided by operating activities* for the six months ended June 30, 2010, increased from the same period in 2009 primarily due to the increase in our operating results.

Financing activities

Significant transactions include:

$3.491 billion received by WPZ in February 2010 from the issuance of $3.5 billion of senior unsecured notes related to our previously discussed restructuring (see Note 9 of Notes to Consolidated Financial Statements);

$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 (see Note 9 of Notes to Consolidated Financial Statements);

$250 million received from revolver borrowings on WPZ s $1.75 billion unsecured credit facility in February 2010 to repay a term loan. As of June 30, 2010, no loans are outstanding on this credit facility (see Note 9 of Notes to Consolidated Financial Statements);

$595 million net cash received in 2009 from the issuance of $600 million aggregate principal amount of 8.75 percent senior unsecured notes due 2020 to fund general corporate expenses and capital expenditures (see Note 9 of Notes to Consolidated Financial Statements).

Investing activities

Significant transactions include:

Capital expenditures totaled $940 million and $1,077 million for 2010 and 2009, respectively.

$148 million of cash received in 2009 as a distribution from Gulfstream following its debt offering.

$100 million cash payment in 2009 for our 51 percent ownership in the joint venture Laurel Mountain.

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.

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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 2010. (See Note 9 of Notes to Consolidated Financial Statements.)

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas and natural gas liquids (NGL), 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.

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 liability of $5 million at June 30, 2010. The value at risk for contracts held for trading purposes was less than $1 million at June 30, 2010 and December 31, 2009.

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
Other	NGL purchases

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The fair value of our nontrading derivatives was a net asset of $294 million at June 30, 2010.

The value at risk for derivative contracts held for nontrading purposes was $33 million at June 30, 2010, and $34 million at December 31, 2009.

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 $332 million as of June 30, 2010. 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.

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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 also is 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 2010 Changes in Internal Controls

There have been no changes during the second quarter of 2010 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, 2009, 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:

Costs of environmental liabilities and complying with existing and future environmental regulations, including those related to climate change and greenhouse gas emissions, could exceed our current expectations.

Our operations are subject to extensive environmental regulation pursuant to a variety of federal, provincial, state and municipal laws and regulations. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, extraction, transportation, treatment and disposal of hazardous substances and wastes, in connection with spills, releases and emissions of various substances into the environment, and in connection with the operation, maintenance, abandonment and reclamation of our facilities. Various governmental authorities, including the U.S. Environmental Protection Agency (EPA) and analogous state agencies and the United States Department of Homeland Security, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations, and permits may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, and the issuance of injunctions limiting or preventing some or all of our operations.

Compliance with environmental laws requires significant expenditures, including clean up costs and damages arising out of contaminated properties. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations for the remediation of contaminated areas and in connection with spills or releases of natural gas and wastes on, under, or from our properties and facilities. Private parties, including the owners of properties through which our pipeline and gathering systems pass, may have the right to pursue legal actions to enforce compliance as well as to seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage arising from our operations.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses. Although we do not expect that the costs of complying with current environmental laws will have a material adverse effect on our financial condition or results of operations, no assurance can be given that the costs of complying with environmental laws in the future will not have such an effect.

Legislative and regulatory responses related to greenhouse gases (GHGs) and climate change creates the potential for financial risk. The United States Congress and certain states have for some time been considering various forms of legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. In addition, increased public awareness and concern may result in more state, federal, and international proposals to reduce or mitigate GHG emissions.

Several bills have been introduced in the United States Congress that would compel GHG emission reductions. In June of 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act which is intended to decrease annual GHG emissions through a variety of measures, including a cap and trade system which limits the amount of GHGs that may be emitted and incentives to reduce the nation s dependence on traditional energy sources. The U.S. Senate is currently considering similar legislation, and numerous states have also announced or adopted programs to stabilize and reduce GHGs. In addition, on December 7, 2009, the EPA issued a final determination that six GHGs are a threat to public safety and welfare. This determination is the latest in a series of EPA actions in 2009 which could ultimately lead to the direct regulation of GHG emissions in our industry by the EPA under the Clean Air Act. While it is not clear whether or when any federal or state climate change laws or regulations will be passed, any of these actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities, and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively impact our cost of and access to capital.

Certain environmental and other groups have suggested that additional laws and regulations may be needed to more closely regulate the hydraulic fracturing process commonly used in natural gas production and legislation has been proposed in Congress to provide for such regulation. We cannot predict whether any federal, state or local legislation or regulation will be enacted in this area and if so, what its provisions would be. If additional levels of reporting, regulation and permitting were required, our operations and those of our customers could be adversely affected.

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We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change. Our regulatory rate structure and our contracts with customers might not necessarily allow us to recover capital costs we incur to comply with the new environmental regulations. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for certain development projects. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, the operation of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our results of operations.

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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	The Williams Companies, Inc., 2007 Incentive Plan (filed on April 8, 2010, as Appendix B to the Company s Definitive Proxy Statement) and incorporated herein by reference.
Exhibit 12	Computation of Ratio of Earnings to Fixed Charges.(1)
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.(1)
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.(1)
Exhibit 32	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.(2)

(1) Filed herewith

(2) Furnished herewith

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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)

July 29, 2010

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