WILLIAMS COMPANIES INC
Form 10-Q
October 29, 2009

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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 September 30, 2009

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 October 26, 2009**
Common Stock, $1 par value	583,130,240 Shares

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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, could, may, should, continues, estimates, expects, forecasts, intends, might, objectives, planned 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 the current economic slowdown and the disruption of 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), 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, 2008, and Part II, Item 1A. Risk Factors of this Quarterly Report on Form 10-Q.

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

(Dollars in millions, except per-share amounts)	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Revenues:				
Exploration & Production	$ 522	$ 861	$ 1,605	$ 2,537
Gas Pipeline	379	407	1,201	1,226
Midstream Gas & Liquids	991	1,392	2,489	4,619
Gas Marketing Services	697	1,716	2,162	5,376
Other	6	6	20	18
Intercompany eliminations	(497)	(1,181)	(1,548)	(3,754)
Total revenues	2,098	3,201	5,929	10,022
Segment costs and expenses:				
Costs and operating expenses	1,537	2,344	4,373	7,374
Selling, general and administrative expenses	126	133	380	375
Other (income) expense net	1	1	33	(145)
Total segment costs and expenses	1,664	2,478	4,786	7,604
General corporate expenses	40	34	118	118
Operating income (loss):				
Exploration & Production	102	356	291	1,273
Gas Pipeline	138	152	449	486
Midstream Gas & Liquids	201	201	414	670
Gas Marketing Services	(6)	16	(14)	(9)
Other	(1)	(2)	3	(2)
General corporate expenses	(40)	(34)	(118)	(118)
Total operating income	394	689	1,025	2,300
Interest accrued	(168)	(162)	(497)	(483)
Interest capitalized	15	16	57	40
Investing income	39	65	2	174
Other income (expense) net	(1)	2	(2)	6
Income from continuing operations before income taxes	279	610	585	2,037
Provision for income taxes	87	199	223	707
Income from continuing operations	192	411	362	1,330

Income (loss) from discontinued operations	2	10	(223)	130
Net income	194	421	139	1,460
Less: Net income attributable to noncontrolling interests	51	55	26	157
Net income attributable to The Williams Companies, Inc.	$ 143	$ 366	$ 113	$ 1,303
Amounts attributable to The Williams Companies, Inc.:				
Income from continuing operations	$ 141	$ 360	$ 266	$ 1,183
Income (loss) from discontinued operations	2	6	(153)	120
Net income	$ 143	$ 366	$ 113	$ 1,303
Basic earnings per common share:				
Income from continuing operations	$ .24	$ .62	$ .45	$ 2.03
Income (loss) from discontinued operations		.01	(.26)	.21
Net income	$ .24	$ .63	$ .19	$ 2.24
Weighted-average shares (thousands)	583,103	577,448	581,121	582,105
Diluted earnings per common share:				
Income from continuing operations	$ .24	$ .61	$ .45	$ 1.99
Income (loss) from discontinued operations		.01	(.26)	.20
Net income	$ .24	$ .62	$ .19	$ 2.19
Weighted-average shares (thousands)	590,059	589,138	588,693	594,630
Cash dividends declared per common share	$ .11	$ .11	$ .33	$ .32

See accompanying notes.

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

(Dollars in millions, except per-share amounts)	September 30, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,640	$ 1,438
Accounts and notes receivable (net of allowance of $32 at September 30, 2009 and $29 at December 31, 2008)	705	884
Inventories	232	260
Derivative assets	700	1,464
Assets of discontinued operations	1	142
Other current assets and deferred charges	212	223
Total current assets	3,490	4,411
Investments	894	971
Property, plant and equipment, at cost	27,095	25,360
Accumulated depreciation, depletion and amortization	(8,631)	(7,619)
Property, plant and equipment net	18,464	17,741
Derivative assets	585	986
Goodwill	1,011	1,011
Assets of discontinued operations		387
Other assets and deferred charges	508	499
Total assets	$ 24,952	$ 26,006
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 799	$ 1,052
Accrued liabilities	833	1,139
Derivative liabilities	566	1,093
Liabilities of discontinued operations		217
Long-term debt due within one year	19	18
Total current liabilities	2,217	3,519
Long-term debt	8,258	7,683
Deferred income taxes	3,466	3,315
Derivative liabilities	606	875
Liabilities of discontinued operations		82
Other liabilities and deferred income	1,550	1,478
Contingent liabilities and commitments (Note 12)		

Equity:		
Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 618 million shares issued at September 30, 2009 and 613 million shares issued at December 31, 2008)	618	613
Capital in excess of par value	8,129	8,074
Retained earnings	795	874
Accumulated other comprehensive loss	(194)	(80)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders equity	8,307	8,440
Noncontrolling interests in consolidated subsidiaries	548	614
Total equity	8,855	9,054
Total liabilities and equity	$ 24,952	$ 26,006

See accompanying notes.

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

	Three months ended September 30,					
	2009			2008		
(Dollars in millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 8,324	$ 529	$ 8,853	$ 7,652	$ 607	$ 8,259
Comprehensive income:						
Net income	143	51	194	366	55	421
Other comprehensive income (loss), net of tax:						
Net unrealized gain (loss) on cash flow hedges, net of reclassification adjustments	(167)		(167)	699	12	711
Foreign currency translation adjustments	50		50	(10)		(10)
Pension and other postretirement benefits net	7		7	3		3
Total other comprehensive income (loss)	(110)		(110)	692	12	704
Total comprehensive income	33	51	84	1,058	67	1,125
Cash dividends common stock	(64)		(64)	(63)		(63)
Dividends and distributions to noncontrolling interests		(32)	(32)		(36)	(36)
Purchase of treasury stock				(109)		(109)
Stock-based compensation, net of tax	14		14	11		11
Issuance of common stock from 5.5% debentures conversion				25		25
Other					1	1
Ending balance	$ 8,307	$ 548	$ 8,855	$ 8,574	$ 639	$ 9,213

	Nine months ended September 30,					
	2009			2008		
(Dollars in millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 8,440	$ 614	$ 9,054	$ 6,375	$ 1,430	$ 7,805

Comprehensive income (loss):						
Net income	113	26	139	1,303	157	1,460
Other comprehensive income (loss), net of tax:						
Net unrealized gain (loss) on cash flow hedges, net of reclassification adjustments	(202)		(202)	243	5	248
Foreign currency translation adjustments	69		69	(27)		(27)
Pension and other postretirement benefits net	19		19	7		7
Total other comprehensive income (loss)	(114)		(114)	223	5	228
Total comprehensive income (loss)	(1)	26	25	1,526	162	1,688
Cash dividends common stock	(192)		(192)	(186)		(186)
Dividends and distributions to noncontrolling interests		(97)	(97)		(90)	(90)
Sale of limited partner units of consolidated partnerships					362	362
Conversion of Williams Partners L.P. subordinated units to common units				1,225	(1,225)	
Purchase of treasury stock				(474)		(474)
Stock-based compensation, net of tax	32		32	75		75
Issuance of common stock from 5.5% debentures conversion	28		28	25		25
Other		5	5	8		8
Ending balance	$ 8,307	$ 548	$ 8,855	$ 8,574	$ 639	$ 9,213

See accompanying notes.

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

(Dollars in millions)	Nine months ended September 30, 2009	2008
OPERATING ACTIVITIES:		
Net income	$ 139	$ 1,460
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,087	953
Provision for deferred income taxes	84	497
Provision for loss on investments, property and other assets	351	19
Net gain on disposition of assets	(4)	(37)
Gain on sale of contractual production rights		(148)
Provision for doubtful accounts and notes	51	11
Amortization of stock-based awards	36	33
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	179	278
Inventories	23	(111)
Margin deposits and customer margin deposits payable	(29)	72
Other current assets and deferred charges	3	(78)
Accounts payable	(76)	(252)
Accrued liabilities	(199)	17
Changes in current and noncurrent derivative assets and liabilities	43	(103)
Other, including changes in noncurrent assets and liabilities	70	(5)
Net cash provided by operating activities	1,758	2,606
FINANCING ACTIVITIES:		
Proceeds from long-term debt	595	674
Payments of long-term debt	(31)	(634)
Proceeds from sale of limited partner units of consolidated partnerships		362
Dividends paid	(192)	(186)
Purchase of treasury stock		(474)
Dividends and distributions paid to noncontrolling interests	(97)	(90)
Changes in restricted cash	34	(20)
Changes in cash overdrafts	(47)	4
Other net	(1)	48
Net cash provided (used) by financing activities	261	(316)
INVESTING ACTIVITIES:		
Capital expenditures*	(1,829)	(2,591)
Purchases of investments/advances to affiliates	(132)	(105)
Proceeds from sale of contractual production rights		148
Distribution from Gulfstream Natural Gas System, L.L.C.	148	

Other net	(5)	83
Net cash used by investing activities	(1,818)	(2,465)
Increase (decrease) in cash and cash equivalents	201	(175)
Cash and cash equivalents at beginning of period	1,439	1,699
Cash and cash equivalents at end of period	$ 1,640	$ 1,524

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* Increases to property, plant and equipment	$ (1,713)	$ (2,593)
Changes in related accounts payable and accrued liabilities	(116)	2
Capital expenditures	$ (1,829)	$ (2,591)

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 August 27, 2009. 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 September 30, 2009, results of operations and changes in equity for the three and nine months ended September 30, 2009 and 2008 and cash flows for the nine months ended September 30, 2009 and 2008.

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.

Goodwill

We perform interim assessments of goodwill if indicators of potential impairment exist. We performed an interim evaluation as of March 31, 2009, and determined that no impairment of our goodwill was necessary. At June 30 and September 30, 2009, no indicators of potential impairment were present. We will perform our annual impairment evaluation as of December 31, 2009, which could result in a material impairment of goodwill.

Subsequent Events

We have evaluated our disclosure of subsequent events through the time of filing this Form 10-Q with the Securities and Exchange Commission on October 29, 2009.

Note 2. Basis of Presentation

Discontinued Operations

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

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

Master Limited Partnerships

We own approximately 23.6 percent of Williams Partners L.P., including 100 percent of the general partner, and incentive distribution rights. Considering the presumption of control of the general partner, Williams Partners L.P. is consolidated within our Midstream segment. For 2009 distribution periods, we have agreed to waive our general partner incentive distribution rights, which we estimated would have totaled $29 million based on expected distribution levels. We have also agreed to provide a credit of up to $10 million to Williams Partners L.P. if general and administrative expenses exceed specified levels. This will decrease our total allocation of income from Williams Partners L.P., resulting in decreased *net income attributable to The Williams Companies, Inc.* and increased *net income attributable to noncontrolling interests.*

We own approximately 47.7 percent of Williams Pipeline Partners L.P., including 100 percent of the general partner, and incentive distribution rights. Considering the presumption of control of the general partner, Williams Pipeline Partners L.P. is consolidated within our Gas Pipeline segment.

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Note 3. Discontinued Operations

Our Venezuela operations include majority ownership in entities that owned and operated the El Furrial and PIGAP II gas compression facilities prior to their expropriation by the Venezuelan government in May 2009. We previously operated these assets under long-term agreements for the exclusive benefit of the state-owned oil company, Petróleos de Venezuela S.A. (PDVSA). Construction of these assets was funded through project financing that is collateralized by the stock, assets, and contract rights of the entities that operated the Venezuela assets and is nonrecourse to us. We and the secured lenders are pursuing rights available to us under our agreements, including contractual and international arbitration. These operations meet the accounting definition of a component of an entity. As a result of the expropriation of the assets and the termination of the associated contracts, we consider these assets to be disposed and thus qualified for reporting as discontinued operations.

Considering the expropriation of the assets and the significant controlling rights of the secured lenders, we no longer control these entities and no longer meet the criteria to consolidate them. In conjunction with the deconsolidation of these entities in the second quarter of 2009, we recorded our retained investment in these entities at zero and recognized a pre-tax gain of $9 million. This carrying value was based on our estimates of probability-weighted discounted cash flows that considered (1) alternate arbitration venues, (2) estimated levels of arbitration awards, (3) the subsequent likelihood and timing of collection, (4) the duration of the arbitration process, (5) a discount rate of 20 percent, and (6) the allocation of arbitration proceeds between parties, including the secured lenders. The use of alternate judgments and/or assumptions would have resulted in a different gain on deconsolidation. The carrying value of our retained investment in these entities was significantly impacted by our assumptions and is not representative of our underlying claims against PDVSA or the country of Venezuela.

The expropriations in the second quarter of 2009 followed an extended period of nonpayment by PDVSA and default notices that we provided in accordance with our agreements. The collection of receivables from PDVSA was historically slower and required more effort than with other customers due to PDVSA s policies and the political environment in Venezuela. In our year-end 2008 analysis, we expected PDVSA to resume regular payments following a February 15, 2009, referendum vote in Venezuela; however, that did not happen. PDVSA s continued nonperformance across the industry, their financial distress, and lack of communications with us caused us to revise our assessment in the first quarter of 2009.

As a result of this and our first-quarter assessment of the low likelihood of PDVSA curing the defaults, we fully reserved $48 million of accounts receivable from PDVSA in the first quarter of 2009. In addition, we ceased revenue recognition of these operations in the first quarter of 2009 as we no longer believed that the collectibility of revenues was reasonably assured. This indicator of impairment required us to review our Venezuela property, plant and equipment for recoverability, which resulted in recording a $211 million impairment charge at March 31, 2009. We estimated this impairment charge using probability-weighted discounted cash flow estimates that considered expected cash flows from (1) the continued operation of the assets considering a complete cure of the default or a partial payment and renegotiation of the contracts, (2) the purchase of the assets by PDVSA, and (3) the results of arbitration with varying degrees of award and collection. Considering the risk associated with operating in Venezuela, we utilized an after-tax discount rate of 20 percent. The use of alternate judgments and/or assumptions would have resulted in the recognition of a different or no impairment charge. Certain deferred charges and credits, which netted to a $30 million charge, were also written off because the related future cash inflows and outflows were no longer expected to occur.

The past due payments from PDVSA triggered technical default of the related project debt under our financing agreements in the fourth quarter of 2008, which resulted in classification of the entire debt balance as current at December 31, 2008.

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Notes (Continued)

Summarized Results of Discontinued Operations

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(Millions)		(Millions)	
Revenues	$	$ 44	$	$ 133
Income (loss) from discontinued operations before (impairments) and gain on sales, gain on deconsolidation, and income taxes	$	$ 17	$ (84)	$ 221
(Impairments) and gain on sales		8	(211)	8
Gain on deconsolidation			9	
(Provision) benefit for income taxes	2	(15)	63	(99)
Income (loss) from discontinued operations	$ 2	$ 10	$ (223)	$ 130
Income (loss) from discontinued operations:				
Attributable to noncontrolling interests	$	$ 4	$ (70)	$ 10
Attributable to The Williams Companies, Inc.	$ 2	$ 6	$ (153)	$ 120

Revenues for the three and nine months ended September 30, 2008, primarily include revenue associated with our discontinued Venezuela operations.

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

Income (loss) from discontinued operations before (impairments) and gain on sales, gain on deconsolidation, and income taxes for the three months ended September 30, 2008, primarily includes the results of operations related to our discontinued Venezuela operations.

Income (loss) from discontinued operations before (impairments) and gain on sales, gain on deconsolidation, and income taxes for the nine months ended September 30, 2008, includes:

- $128 million of gains related to the favorable resolution of matters involving pipeline transportation rates associated with our former Alaska operations;
- $62 million of income related to our discontinued Venezuela operations;
- $54 million of income related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank;
- A $10 million charge associated with a settlement primarily related to the sale of natural gas liquid (NGL) pipeline systems in 2002;
- A $10 million charge associated with an oil purchase contract related to our former Alaska refinery.

(Impairments) and gain on sales for the nine months ended September 30, 2009, reflects the previously described $211 million impairment of our Venezuela property, plant, and equipment.

(Impairments) and gain on sales for the three and nine months ended September 30, 2008, primarily represents $9 million of final proceeds from the sale of our former power business.

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

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Notes (Continued)

Summarized Assets and Liabilities of Discontinued Operations

	September 30, 2009	December 31, 2008
	(Millions)	
Cash and cash equivalents	$	$ 1
Accounts receivable net	1	62
Other current assets		79
Total current assets	1	142
Property, plant and equipment net		324
Other noncurrent assets		63
Total noncurrent assets		387
Total assets	$ 1	$ 529
Long-term debt due within one year	$	$ 177
Other current liabilities		40
Total current liabilities		217
Total noncurrent liabilities		82
Total liabilities	$	$ 299

Note 4. Asset Sales, Impairments and Other Accruals

The following table presents significant gains or losses reflected in *other (income) expense net* within *segment costs and expenses*:

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(Millions)		(Millions)	
Exploration & Production				
Gain on sale of contractual right to an international production payment	$	$	$	$(148)
Impairment of certain natural gas producing properties		14		14
Penalties from early release of drilling rigs			32	
Gas Pipeline				
Gain on sale of certain south Texas assets		(10)		(10)

Additional Items

In first-quarter 2009, Midstream recorded a $75 million impairment charge related to an other-than-temporary loss in value associated with its Venezuelan investment in Accroven SRL (Accroven), which is reflected in loss from

investments within *investing income*. Accroven owns and operates gas processing facilities and an NGL fractionation plant for the exclusive benefit of PDVSA. The deteriorating circumstances in the first quarter of 2009 for our Venezuelan operations (see Note 3) caused us to review our investment in Accroven. We utilized a probability-weighted discounted cash flow analysis, which included an after-tax discount rate of 20 percent to reflect the risk associated with operating in Venezuela. (See Note 10.) Accroven was not part of the operations that were expropriated by the Venezuelan government in May 2009. Subsequent to June 30, 2009, we have been engaged in discussions regarding the eventual disposition of Accroven.

In addition, Exploration & Production recorded an $11 million impairment related to a cost-based investment in first-quarter 2009, which is included within *investing income*. Exploration & Production has a four percent interest in a Venezuelan corporation which owns and operates oil and gas activities. This investment resulted from our previous 10 percent direct working interest in a concession that was converted to a reduced interest in a mixed company at the direction of the Venezuelan government in 2006. Considering our evaluation of the deteriorating financial condition of this corporation, we have recorded an other-than-temporary decline in value of our remaining investment balance.

Investing income within our Other segment includes gains of $10 million from sales of cost-based investments for the nine months ended September 30, 2008.

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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* includes:

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(Millions)		(Millions)	
Current:				
Federal	$ (12)	$ 32	$ 44	$ 299
State	(2)	(11)	5	34
Foreign	7	3	21	15
	(7)	24	70	348
Deferred:				
Federal	83	149	140	312
State	11	23	18	41
Foreign		3	(5)	6
	94	175	153	359
Total provision	$ 87	$ 199	$ 223	$ 707

The effective income tax rate on the total provision for the three months ended September 30, 2009, is less than the federal statutory rate due primarily to taxes on foreign operations and the impact of nontaxable noncontrolling interests. The effective income tax rate on the total provision for the three months ended September 30, 2008, is less than the federal statutory rate due primarily to the impact of nontaxable noncontrolling interests.

The effective income tax rate on the total provision for the nine months ended September 30, 2009, is greater than the federal statutory rate due primarily 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. The effective income tax rate on the total provision for the nine months ended September 30, 2008, is approximately equal to the federal statutory rate due primarily to offsetting impacts of state income taxes reduced by nontaxable noncontrolling interests.

During the next twelve months, we do not expect ultimate resolution of any uncertain tax position associated with a domestic or international matter 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.

Note 6. Earnings Per Common Share from Continuing Operations

Basic and diluted earnings per common share are computed as follows:

Three months ended September 30,		Nine months ended September 30,	
2009	2008	2009	2008
(Dollars in millions, except per share amounts; shares in thousands)			
$ 141	$ 360	$ 266	$ 1,183

Income from continuing operations attributable to The Williams Companies, Inc. available to common stockholders for basic and diluted earnings per common share (1)				
Basic weighted-average shares	583,103	577,448	581,121	582,105
Effect of dilutive securities:				
Nonvested restricted stock units	2,544	1,304	1,911	1,337
Stock options	2,148	3,468	1,834	4,003
Convertible debentures	2,264	6,918	3,827	7,185
Diluted weighted-average shares	590,059	589,138	588,693	594,630
Earnings per common share from continuing operations:				
Basic	$ .24	$ .62	$ .45	$ 2.03
Diluted	$ .24	$ .61	$ .45	$ 1.99

(1) The nine-month period ended September 30, 2009 includes $1 million and the three- and nine-month periods ended September 30, 2008 include $1 million and $2 million, respectively, of interest expense, net of tax, associated with our convertible debentures. These amounts have been added back to *income from continuing operations attributable to The Williams Companies, Inc. available to common stockholders* to calculate diluted earnings per common share.

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

	September 30, 2009	September 30, 2008
Options excluded (millions)	6.1	1.9
Weighted-average exercise prices of options excluded	$ 25.99	$ 37.04
Exercise price ranges of options excluded	$ 17.10 - $42.29	$ 32.05 - $42.29
Third quarter weighted-average market price	$ 16.73	$ 30.22

Note 7. Employee Benefit Plans

Net periodic benefit expense is as follows:

	Pension Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(Millions)			
Components of net periodic pension expense:				
Service cost	$ 8	$ 6	$ 24	$ 17
Interest cost	16	15	47	45
Expected return on plan assets	(16)	(20)	(46)	(59)
Amortization of prior service cost			1	
Amortization of net actuarial loss	11	3	32	10
Amortization of regulatory asset	1		1	
Net periodic pension expense	$ 20	$ 4	$ 59	$ 13

	Other Postretirement Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(Millions)			
Components of net periodic other postretirement benefit expense:				
Service cost	$	$ 1	$ 1	$ 2
Interest cost	4	5	12	14
Expected return on plan assets	(2)	(4)	(6)	(10)
Amortization of prior service credit	(3)		(8)	
Amortization of net actuarial loss	1		2	
Amortization of regulatory asset	2	1	4	3
Net periodic other postretirement benefit expense	$ 2	$ 3	$ 5	$ 9

During the nine months ended September 30, 2009, we contributed $61 million to our pension plans and $11 million to our other postretirement benefit plans. We do not presently anticipate making any additional contributions to our pension plans in the remainder of 2009. We presently anticipate making additional contributions of approximately $4 million to our other postretirement benefit plans in 2009 for a total of approximately $15 million.

Note 8. Inventories

Inventories are as follows:

	September 30, 2009	December 31, 2008
	(Millions)	
Natural gas liquids and olefins	$ 58	$ 57
Natural gas in underground storage	63	97
Materials, supplies and other	111	106
	$ 232	$ 260

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Note 9. Debt and Banking Arrangements

Revolving Credit and Letter of Credit Facilities (Credit Facilities)

At September 30, 2009, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Credit Facilities Expiration	Letters of Credit at September 30, 2009 (Millions)
$700 million unsecured credit facilities	October 2010	$ 222
$1.5 billion unsecured credit facility	May 2012	
$200 million Williams Partners L.P. unsecured credit facility	December 2012	
		$ 222

Lehman Commercial Paper Inc., which is committed to fund up to $70 million of our $1.5 billion revolving credit facility, filed for bankruptcy in October 2008. Lehman Brothers Commercial Bank, which has not filed for bankruptcy, is committed to fund up to $12 million of Williams Partners L.P. s $200 million revolving credit facility. We expect that our ability to borrow under these facilities is reduced by these committed amounts. The committed amounts of other participating banks under these agreements remain in effect and are not impacted by the above.

In second-quarter 2009, two of our unsecured revolving credit facilities totaling $500 million expired and were not renewed. These facilities were originated primarily in support of our former power business.

Issuances

On March 5, 2009, we issued $600 million aggregate principal amount of 8.75 percent senior unsecured notes due 2020 to certain institutional investors in a private debt placement. In August 2009, we completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

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.

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 primarily consists 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 primarily consists of over-the-counter (OTC) instruments such as forwards, swaps, and options. These options, 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

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standard Black-Scholes option pricing model. Prior to the third quarter of 2009, these options were included in Level 3 as a significant input to the model, implied volatility by location, was considered unobservable. However, due to increased transparency over the past several quarters, we now consider this input to be observable and have included these options in Level 2.

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 consists of instruments valued using industry standard pricing models and other valuation methods that utilize 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.

Fair Value Measurements Using:

	September 30, 2009				December 31, 2008			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Assets:								
Energy derivatives	$ 208	$ 1,070	$ 7	$ 1,285	$ 680	$ 1,223	$ 547	$ 2,450
Other assets	21			21	13		7	20
Total assets	$ 229	$ 1,070	$ 7	$ 1,306	$ 693	$ 1,223	$ 554	$ 2,470
Liabilities:								
Energy derivatives	$ 206	$ 964	$ 2	$ 1,172	$ 615	$ 1,313	$ 40	$ 1,968
Total liabilities	$ 206	$ 964	$ 2	$ 1,172	$ 615	$ 1,313	$ 40	$ 1,968

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 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.

Contracts for which fair value can be estimated from executed transactions or broker quotes corroborated by other market data are generally classified within Level 2. 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 expiring in the next

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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 requiring valuation models 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 September 30, 2009, consist of natural gas liquids swaps for our Midstream segment as well as natural gas index transactions that are used to manage the physical requirements of our Exploration & Production segment and our Midstream segment.

The following tables present a reconciliation of changes in the fair value of net 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 September 30,			
	2009		2008	
	Net Derivatives	Other Assets	Net Derivatives	Other Assets
	(Millions)			
Beginning balance	$ 413	$	$ (641)	$ 10
Realized and unrealized gains (losses):				
Included in *income from continuing operations*	161		(2)	
Included in *other comprehensive income (loss)*	(233)		894	
Purchases, issuances, and settlements	(163)		27	
Transfers into Level 3			4	
Transfers out of Level 3	(173)			
Ending balance	$ 5	$	$ 282	$ 10
Net unrealized gains (losses) included in *income from continuing operations* relating to instruments still held at September 30	$ (1)	$	$ 22	$

	Nine months ended September 30,			
	2009		2008	
	Net Derivatives	Other Assets	Net Derivatives	Other Assets
	(Millions)			
Beginning balance	$ 507	$ 7	$ (14)	$ 10
Realized and unrealized gains (losses):				
Included in *income from continuing operations*	480		(51)	
Included in *other comprehensive income (loss)*	(329)		254	
Purchases, issuances, and settlements	(480)	(7)	91	
Transfers into Level 3			3	
Transfers out of Level 3	(173)		(1)	
Ending balance	$ 5	$	$ 282	$ 10
	$ 2	$	$ 7	$

Net unrealized gains included in *income from continuing operations* relating to instruments still held at September 30

Realized and unrealized gains (losses) included in *income from continuing operations* for the above periods are reported in *revenues* in our Consolidated Statement of Income. Reclassification of fair value into and out of Level 3 is made at the end of each quarter.

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The following table presents, by level within the fair value hierarchy, certain assets that have been measured at fair value on a nonrecurring basis, including certain items reported as discontinued operations.

Fair Value Measurements Using:

	September 30, 2009				Total Losses for three months ended September 30, 2009	Total Losses for nine months ended September 30, 2009
	Level 1	Level 2	Level 3			
	(Millions)					
Impairments:						
Midstream Venezuelan property (see Note 3)	$	$	$	(a)	$	$ (211)
Midstream investment in Accroven (see Note 4)				(b)		(75)
Exploration & Production cost-based investment (see Note 4)				(b)		(11)
	$	$	$		$	$ (297)

(a) Fair value measured at March 31, 2009, was $106 million. These assets were expropriated by the Venezuelan government during the second quarter of 2009 and the entities that previously owned these assets are no longer consolidated within our Midstream segment. We recorded our retained noncontrolling investment in

these entities at zero and recognized a gain of $9 million on the deconsolidation. (See Note 3.)

(b) Fair value measured at March 31, 2009, was zero.

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 Transcontinental Gas Pipeline Company, LLC (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 September 30, 2009 and December 31, 2008, approximately 97 percent of our long-term debt was publicly traded.

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 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 notes and other noncurrent receivables, margin deposits, customer margin deposits payable, cost-based investments and auction rate securities.

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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

	September 30, 2009		December 31, 2008	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
		(Millions)		
Cash and cash equivalents	$ 1,640	$ 1,640	$ 1,438	$ 1,438
Restricted cash (current and noncurrent)	$ 34	$ 34	$ 37	$ 37
ARO Trust Investments	$ 21	$ 21	$ 13	$ 13
Long-term debt, including current portion(a)	$(8,274)	$(8,903)	$(7,697)	$(6,140)
Guarantees	$ (37)	$ (33)	$ (38)	$ (32)
Other	$ 12	$ 8 (b)	$ 4	$ (13) (b)
Net energy derivatives:				
Energy commodity cash flow hedges	$ 222	$ 222	$ 458	$ 458
Other energy derivatives	$ (109)	$ (109)	$ 24	$ 24

(a) Excludes capital lease obligations.

(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 $3 million and $17 million at September 30, 2009 and December 31, 2008, respectively.

Energy Commodity Derivatives

Risk Management Activities

We are exposed to market risk from changes in energy commodity prices within our operations. We manage this risk on an enterprise basis and may utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases and sales of natural gas and forecasted sales of NGLs attributable to commodity price risk. Certain of these derivatives utilized for risk management purposes have been designated as cash flow

hedges, while other derivatives have not been designated as cash flow hedges or do not qualify for hedge accounting despite hedging our future cash flows on an economic basis.

Exploration & Production produces, buys and sells natural gas at different locations throughout the United States. To reduce exposure to a decrease in revenues 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. Exploration & Production s 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.

Midstream produces and sells NGLs at different locations throughout the United States. Midstream also buys natural gas to satisfy the required fuel and shrink needed to generate NGLs. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices or increases in costs and operating expenses from fluctuations in natural gas market prices, we may enter into NGL or natural gas swap agreements, financial forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs and purchases of natural gas. Midstream s 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.

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Gas Marketing Services supports our natural gas business by providing marketing and risk management services, which include marketing the gas produced by Exploration & Production and procuring fuel and shrink for Midstream. Gas Marketing Services also enters 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 margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements, and financial option contracts to mitigate the price risk associated with these contracts. Hedges for transportation contracts are designated as cash flow hedges and 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. Hedges for storage contracts have not been designated as hedging instruments, despite economically hedging the expected cash flows generated by those agreements.

Other activities

Gas Marketing Services also enters into 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 amounts of the net long (short) positions in our commodity derivatives portfolio as of September 30, 2009. Natural gas is presented in millions of British Thermal Units (MMBtu) and NGLs is presented in gallons. The volumes presented for options that comprise zero-cost collars represent one side of the short position. While the index volumes are significant, they represent less than 1 percent of the fair value of our net derivative balance.

Derivative Notional Volumes		Measurement	Fixed Price	Basis	Index	Options
Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(69,905,000)	(67,140,000)		(282,355,000)
Gas Marketing Services	Risk Management	MMBtu	*	*		
Midstream	Risk Management	MMBtu	1,405,000	1,405,000		
Midstream	Risk Management	Gallons	(33,453,000)			
Not Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu			(70,636,726)	

Gas Marketing Services	Risk Management	MMBtu	(10,027,499)	(6,940,000)	449,996
Midstream	Risk Management	MMBtu			67,250,563
Midstream	Risk Management	Gallons	(6,930,000)		(5,997,600)
Gas Marketing Services	Other	MMBtu	(859,969)	(5,572,500)	

* Volumes related to offsetting positions net to zero.

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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 twelve months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	September 30, 2009	
	Assets	Liabilities
	(Millions)	
Designated as hedging instruments	$ 419	$ 197
Not designated as hedging instruments:		
Legacy natural gas contracts from former power business	589	613
All other	277	362
Total derivatives not designated as hedging instruments	866	975
Total derivatives	$ 1,285	$ 1,172

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 (AOCI) or revenues.

	Three months ended September 30, 2009 (Millions)	Nine months ended September 30, 2009 (Millions)	Classification
Net gain (loss) recognized in other comprehensive income (effective portion)	$ (91)	$ 180	AOCI
Net gain reclassified from accumulated other comprehensive income into income (effective portion)	$ 176	$ 506	Revenues
Gain (loss) recognized in income (ineffective portion)	$ (1)	$ 1	Revenues

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness.

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

	Three months ended September 30, 2009 (Millions)	Nine months ended September 30, 2009 (Millions)
Revenues	$ 8	$ 28
Costs and operating expenses	13	27

Net gain (loss)	$ (5)	$ 1

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

Credit-risk-related features

Certain of our derivative contracts contain credit-risk-related provisions that would require us, in certain circumstances, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor s and/or Moody s Investors Service. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability. Additionally, Exploration & Production has an unsecured credit agreement with certain banks related to hedging activities. We are not required to provide collateral support for net derivative liability positions under the credit agreement as long as the value of Exploration & Production s domestic natural gas

Notes (Continued)

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 positions on hedges entered into under the credit agreement.

As of September 30, 2009, we have collateral posted to derivative counterparties totaling $78 million, all of which is 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 $154 million, which includes a reduction of $4 million to our liability balance for our 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, is $80 million.

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 September 30, 2009, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to four years. Based on recorded values at September 30, 2009, $100 million of net gains (net of income tax provision of $61 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of September 30, 2009. 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 connection with agreements executed to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers that may require the indemnification of certain claims for additional royalties that the producers may be required to pay as a result of such settlements. Transco, through its agent, Gas Marketing Services, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received certain demands and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined. However, management believes that the probability of material payments is remote.

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), our Exploration & Production segment entered into a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, we guarantee a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. We have an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to exceed the minimum purchase price.

We are required by certain lenders to ensure that the interest rates received by them under various loan agreements are not reduced by taxes by providing for the reimbursement of any taxes required to be paid by the lender. The maximum potential amount of future payments under these indemnifications is based on the related borrowings. 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.

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

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approximately $41 million at September 30, 2009. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is approximately $37 million at September 30, 2009.

Former managing directors of Gulf Liquids are involved in litigation related to the construction of gas processing plants. Gulf Liquids has indemnity obligations to the former managing directors for legal fees and potential losses that may result from this litigation. Claims against these former managing directors have been settled and dismissed after payments on their behalf by directors and officers insurers. Some unresolved issues remain between us and these insurers, but no amounts have been accrued for any potential liability.

We have guaranteed the performance of a former subsidiary of our wholly owned subsidiary MAPCO Inc., under a coal supply contract. This guarantee was granted by MAPCO Inc. upon the sale of its former subsidiary to a third party in 1996. The guaranteed contract provides for an annual supply of a minimum of 2.25 million tons of coal. Our potential exposure is dependent on the difference between current market prices of coal and the pricing terms of the contract, both of which are variable, and the remaining term of the contract. Given the variability of the terms, the maximum future potential payments cannot be determined. We believe that our likelihood of performance under this guarantee is remote. In the event we are required to perform, we are fully indemnified by the purchaser of MAPCO Inc. s former subsidiary. This guarantee expires in December 2010 and has no carrying value.

We have guaranteed commercial letters of credit totaling $20 million on behalf of Accroven. These expire in January 2010 and have no carrying value.

We have provided guarantees on behalf of certain entities in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. There are no expiration dates associated with these guarantees. No amounts have been accrued at September 30, 2009.

At September 30, 2009, we do not expect any of these guarantees to have a material impact on our future liquidity or financial position. However, if we are required to perform on any of 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 September 30, 2009, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 22	$ 23
Energy marketers and traders	32	526
Financial institutions	736	736
	$ 790	1,285
Credit reserves		
Gross credit exposure from derivatives		$ 1,285

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We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of September 30, 2009, excluding collateral support discussed below, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 2	$ 2
Energy marketers and traders	25	35
Financial institutions	230	230
	$ 257	267
Credit reserves		
Net credit exposure from derivatives		$ 267

(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 seven largest net counterparty positions represent approximately 95 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are five counterparty positions, representing 73 percent of our net credit exposure from derivatives, associated with Exploration & Production s hedging facility. Under certain conditions, the terms of this credit agreement may require the participating financial institutions to deliver collateral support to a designated collateral agent (which is another participating financial institution in the agreement). The level of collateral support required is dependent on whether the net position of the counterparty financial institution exceeds specified thresholds. The thresholds may be subject to prescribed reductions based on changes in the credit rating of the counterparty financial institution.

At September 30, 2009, the designated collateral agent holds $52 million of collateral support on our behalf under Exploration & Production s hedging facility. In addition, we hold collateral support, including letters of credit, of $2 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.

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Refund proceedings

Although we entered into the State Settlement and Utilities Settlement, which resolved 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 we anticipate will satisfy 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 September 30, 2009. Collection of the interest and the payment of interest on refund amounts from the escrow accounts is 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:

State court litigation in California brought on behalf of certain business and governmental entities that purchased gas for their use. On March 23, 2009, we reached a settlement for an insignificant amount that resolved all California gas index litigation. In May 2009, these cases were dismissed with prejudice.

Class action 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 October 29, 2008, the Tennessee appellate court reversed the state court s dismissal of the plaintiffs claims on federal preemption grounds and sent the case back to the lower court for further proceedings. We and other defendants appealed the reversal to the Tennessee Supreme Court, and we expect the court s ruling in 2010.

On January 13, 2009, the Missouri state court dismissed a case for lack of standing. The plaintiff has appealed.

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

Notes (Continued)

costs of any such remediation will depend upon the scope of the remediation. At September 30, 2009, 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 September 30, 2009, we have accrued liabilities of $8 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. The new standards would 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 of these additions that may be required to meet these regulations. We expect that costs associated with these compliance efforts will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At September 30, 2009, we have accrued liabilities totaling $6 million for these costs.

In April 2007, the New Mexico Environment Department s (NMED) Air Quality Bureau issued a notice of violation (NOV) to Williams Four Corners, LLC (Four Corners) that alleged various emission and reporting violations in connection with our Lybrook gas processing plant s flare and leak detection and repair program. In December 2007, the NMED proposed a penalty of approximately $3 million. In July 2008, the NMED issued an NOV to Four Corners that alleged air emissions permit exceedances for three glycol dehydrators at one of our compressor facilities and proposed a penalty of approximately $103,000. We are discussing the proposed penalties with the NMED.

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.

Former operations, including operations classified as discontinued

In connection with the sale of certain assets and businesses, we have retained responsibility, through indemnification of the purchasers, for environmental and other liabilities existing at the time the sale was consummated, as described below.

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Notes (Continued)

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At September 30, 2009, we have accrued liabilities of $8 million for such excess costs.

Other

At September 30, 2009, we have accrued environmental liabilities of $14 million related primarily to our:

- Potential indemnification obligations to purchasers of our 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.

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.

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 the amount cannot be reasonably estimated at this time.

Other Legal Matters

Will Price (formerly Quinque)

In 2001, fourteen 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. We are awaiting a decision from the court. The amount of any possible liability cannot be reasonably estimated at this time.

Grynberg

In 1998, the U.S. Department of Justice (DOJ) informed us that Jack Grynberg, an individual, had filed claims on behalf of himself and the federal government, in the United States District Court for the District of Colorado under the False Claims Act against us, certain of our wholly owned subsidiaries and approximately 300 other energy companies. The claims sought an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys fees, and costs. In connection with our sales of Kern River Gas Transmission in 2002 and Texas Gas Transmission Corporation in 2003, we agreed to indemnify the purchasers for any liability relating to this claim, including legal fees. In 1999, the DOJ announced that it would not intervene in any of the Grynberg cases. Also in 1999, the Panel on Multi-District Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. The District Court dismissed all claims against us and our wholly owned subsidiaries. On March 17, 2009, the Tenth Circuit Court of Appeals

Notes (Continued)

affirmed the District Court s dismissal. On October 5, 2009, the United States Supreme Court denied Grynberg s petition for a writ of certiorari requesting review of the Tenth Circuit Court of Appeal s ruling. This matter is concluded.

Securities class actions

Shareholder class action suits were filed against us in 2002 in the United States District Court for the Northern District of Oklahoma alleging that we and co-defendants, WilTel, previously a subsidiary known as Williams Communications, and certain corporate officers, acted jointly and separately to inflate the price of WilTel securities.

In 2007, the court granted various defendants motions for summary judgment and entered judgment for us and the other defendants. On February 18, 2009, the Tenth Circuit Court of Appeals affirmed the lower court s decision. The plaintiffs did not request a writ of certiorari from the United States Supreme Court to appeal the Tenth Circuit s ruling. This matter is concluded.

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.

Wyoming severance taxes

In August 2006, the Wyoming Department of Audit (DOA) assessed our subsidiary, Williams Production RMT Company, additional severance tax and interest for the production years 2000 through 2002. In addition, the DOA notified us of an increase in the taxable value of our interests for ad valorem tax purposes. We disputed the DOA s interpretation of the statutory obligation and appealed this assessment to the Wyoming State Board of Equalization (SBOE). The SBOE upheld the assessment and remanded it to the DOA to address the disallowance of a credit. We appealed to the Wyoming Supreme Court but the court ruled against us in December 2008. The negative assessment for the 2000-2002 time period resulted in additional severance and ad valorem taxes of $4 million. During 2009, we have made partial payments totaling $30 million, including interest, for periods through 2008 and have an additional $9 million accrued at September 30, 2009, related to this matter representing our estimated remaining exposure, including interest. On April 14, 2009, the Wyoming Supreme Court denied our petition for rehearing and issued its mandate affirming its prior published decision in this case.

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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. The plaintiffs claim that the class might be in excess of 500 individuals and seek an accounting and damages. We have reached a final partial settlement agreement for an amount that was previously accrued. We anticipate trial in 2010 on remaining issues related to royalty payment calculation and obligations under specific lease provisions. 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.

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 September 30, 2009, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

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

Summary

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

Note 13. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Our master limited partnerships, Williams Partners L.P. and Williams Pipeline Partners L.P., are consolidated within our Midstream and Gas Pipeline segments, respectively. (See Note 2.) Other primarily consists of corporate operations.

Performance Measurement

We currently evaluate performance based upon *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses*, *equity earnings (losses)* and *income*

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Notes (Continued)

(loss) from investments. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

External revenues of our Exploration & Production segment are presented net of transportation expenses and royalties due third parties on intersegment sales. In some periods, transportation expenses and royalties due third parties on intersegment sales may exceed other external revenues.

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

	Exploration & Production	Gas Pipeline	Midstream	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
Three months ended September 30, 2009							
Segment revenues:							
External	$ 159	$ 374	$ 970	$ 593	$ 2	$	$ 2,098
Internal	363	5	21	104	4	(497)	
Total revenues	$ 522	$ 379	$ 991	$ 697	$ 6	$ (497)	$ 2,098
Segment profit (loss)	$ 106	$ 157	$ 222	$ (6)	$ (1)	$	$ 478
Less equity earnings	4	19	21				44
Segment operating income (loss)	$ 102	$ 138	$ 201	$ (6)	$ (1)	$	434
General corporate expenses							(40)
Total operating income							$ 394
Three months ended September 30, 2008							
Segment revenues:							
External	$ (101)	$ 403	$ 1,398	$ 1,499	$ 2	$	$ 3,201
Internal	962	4	(6)	217	4	(1,181)	
Total revenues	$ 861	$ 407	$ 1,392	$ 1,716	$ 6	$ (1,181)	$ 3,201
Segment profit (loss)	$ 361	$ 173	$ 229	$ 16	$ (2)	$	$ 777
Less equity earnings	5	21	28				54
Segment operating income (loss)	$ 356	$ 152	$ 201	$ 16	$ (2)	$	723
General corporate expenses							(34)

Total operating income	$ 689

	Exploration & Production	Gas Pipeline	Midstream	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
Nine months ended September 30, 2009							
Segment revenues:							
External	$ 458	$ 1,180	$ 2,439	$ 1,843	$ 9	$	$ 5,929
Internal	1,147	21	50	319	11	(1,548)	
Total revenues	$ 1,605	$ 1,201	$ 2,489	$ 2,162	$ 20	$ (1,548)	$ 5,929
Segment profit (loss)	$ 303	$ 498	$ 371	$ (14)	$ 3	$	$ 1,161
Less:							
Equity earnings	12	49	32				93
Loss from investments			(75)				(75)
Segment operating income (loss)	$ 291	$ 449	$ 414	$ (14)	$ 3	$	1,143
General corporate expenses							(118)
Total operating income							$ 1,025
Nine months ended September 30, 2008							
Segment revenues:							
External	$ (276)	$ 1,200	$ 4,619	$ 4,472	$ 7	$	$ 10,022
Internal	2,813	26		904	11	(3,754)	
Total revenues	$ 2,537	$ 1,226	$ 4,619	$ 5,376	$ 18	$ (3,754)	$ 10,022
Segment profit (loss)	$ 1,287	$ 532	$ 737	$ (9)	$ (2)	$	$ 2,545
Less equity earnings	14	46	67				127
Segment operating income (loss)	$ 1,273	$ 486	$ 670	$ (9)	$ (2)	$	2,418
General corporate expenses							(118)
Total operating income							$ 2,300

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Notes (Continued)

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

	Total Assets	
	September 30, 2009	December 31, 2008
	(Millions)	
Exploration & Production	$ 9,662	$ 10,286
Gas Pipeline	9,315	9,149
Midstream	7,095	6,501
Gas Marketing Services (1)	1,382	3,064
Other	3,307	3,532
Eliminations (2)	(5,810)	(7,055)
	24,951	25,477
Discontinued operations (see Note 3)	1	529
Total	$ 24,952	$ 26,006

(1) The decrease in Gas Marketing Services total assets is primarily due to the fluctuations in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Gas Marketing Services derivative assets are substantially offset by their derivative liabilities.

(2) The decrease in Eliminations is primarily due to a decrease in the intercompany

derivative balances.

Property Insurance Changes

As a result of damage caused by recent hurricanes, the availability of named windstorm insurance has been significantly reduced. Additionally, named windstorm insurance coverage that is available for offshore assets comes at significantly higher premium amounts, higher deductibles and lower coverage limits. Considering these changes, we have reduced the overall named windstorm property insurance coverage for our assets in the Gulf of Mexico area beginning in the second quarter of 2009. In addition, certain assets are no longer covered for named windstorm losses, primarily including certain offshore lateral pipelines and a processing plant. The changes in named windstorm coverage are summarized as follows:

Named Windstorm Property Insurance

	Current Coverage		**Prior Coverage**	
	Offshore	**Onshore**	**Offshore**	**Onshore**
	($ millions)			
Deductible per occurrence	$ 50	$16	$10 combined	
Aggregate limit per policy year	$37.5*	$90	$150 combined	

* 50 percent of losses above $50 million

Note 14. Accounting Standards Issued But Not Yet Adopted

In September 2009, The Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2009-12, Fair Value Measurements and Disclosures (Topic 820): Investments in Certain Entities That Calculate Net Asset Value Per Share (or Its Equivalent). This Update amends Topic 820 by providing additional guidance for the fair value measurement of investments in certain entities that calculate net asset value per share (or its equivalent). The amendments in this Update permit, as a practical expedient, a reporting entity to estimate the fair value of an investment that is within its scope using the net asset value per share of the investment (or its equivalent) if the net asset value of the investment is calculated in a manner consistent with the measurement principles of Topic 946 as of the reporting entity s measurement date, including measurement of all or substantially all of the underlying investments of the investee. The amendments also require disclosures, by major category of investment, about the attributes of investments within the scope of this Update, such as the nature of any restrictions on the investor s ability to redeem its investments at the measurement date, any unfunded commitments, and the investment strategies of the investees. The amendments in this Update are effective for interim and annual periods ending after December 15, 2009. We will assess the application of this Update on our Consolidated Financial Statements.

In August 2009, the FASB issued Accounting Standards Update No. 2009-5, Fair Value Measurements and Disclosures (Topic 820) Measuring Liabilities at Fair Value. This Update provides clarification that in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting

Notes (Continued)

entity is required to measure fair value using one or more prescribed techniques. The amendments in this Update also clarify that when estimating the fair value of a liability, a reporting entity is not required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents the transfer of the liability. Additionally, this Update clarifies that both a quoted price in an active market for the identical liability at the measurement date and the quoted price for the identical liability when traded as an asset in an active market when no adjustments to the quoted price of the asset are required are Level 1 fair value measurements. The guidance provided in this Update is effective for us beginning with the fourth quarter of 2009. We are currently evaluating this Update to determine the impact to our Consolidated Financial Statements.

In December 2008, the FASB issued FASB Staff Position No. FAS 132 (R)-1, Employers Disclosures about Postretirement Benefit Plan Assets (FSP FAS 132 (R)-1). This FASB Staff Position (FSP) amends FASB Statement No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits (SFAS No. 132 (R)), to provide guidance on an employer s disclosures about plan assets of a defined benefit pension or other postretirement plan. FSP FAS 132 (R)-1 applies to an employer that is subject to the disclosure requirements of SFAS No. 132(R). An employer is required to disclose information about how investment allocation decisions are made, including factors that are pertinent to an understanding of investment policies and strategies. An employer should disclose separately for pension plans and other postretirement benefit plans the fair value of each major category of plan assets as of each annual reporting date for which a statement of financial position is presented. Asset categories should be based on the nature and risks of assets in an employer s plan(s). An employer is required to disclose information that enables users of financial statements to assess the inputs and valuation techniques used to develop fair value measurements of plan assets at the annual reporting date. For fair value measurements using significant unobservable inputs (Level 3), an employer should disclose the effect of the measurements on changes in plan assets for the period. An employer should provide users of financial statements with an understanding of significant concentrations of risk in plan assets. The disclosures about plan assets required by FSP FAS 132 (R)-1 are to be provided for fiscal years ending after December 15, 2009. Upon initial application, the provisions of FSP FAS 132 (R)-1 are not required for earlier periods that are otherwise presented for comparative purposes. Earlier application of the provisions of FSP FAS 132 (R)-1 is permitted. We are evaluating the application of this FSP on our disclosures in our Consolidated Financial Statements.

In June 2009, the FASB issued SFAS No. 167, Amendments to FASB Interpretation No. 46(R) (SFAS No. 167). This Statement amends Interpretation 46(R) to require an entity to perform a qualitative analysis to determine whether the entity s variable interest or interests give it a controlling financial interest in a variable interest entity (VIE). This analysis identifies the primary beneficiary of a VIE as the entity that has both the power to direct the activities that most significantly impact the VIE s economic performance and the obligation to absorb losses or the right to receive benefits of the VIE. SFAS No. 167 amends Interpretation 46(R) to replace the quantitative-based risks and rewards approach previously required for determining the primary beneficiary of a VIE. SFAS No. 167 is effective as of the beginning of an entity s first annual reporting period that begins after November 15, 2009 and for interim periods within that first annual reporting period. Earlier application is prohibited. We will assess the application of this Statement on our Consolidated Financial Statements.

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

Company Outlook

The overall economic recession, related lower energy commodity price environment, and challenging financial markets during the past year have resulted in sharply lower results of operations, cash flow from operations and capital expenditures in 2009 compared to 2008. Anticipating these circumstances, our plan for 2009 was built around the transition from significant growth to a focus on sustaining our current operations and reducing costs where appropriate. Although capital expenditures were reduced compared to the prior year, we continued to invest in our businesses with a focus on completing major projects, meeting legal, regulatory, and/or contractual commitments, and maintaining a reduced level of natural gas production development. During this period, we were also able to take advantage of market conditions and seize opportunities to enter new markets and expand our presence in existing markets to further position our businesses for future growth.

We believe we are well positioned to capture growth opportunities as economic conditions improve and commodity prices strengthen. The economic environment in the third quarter has improved compared to earlier in the year. In addition, economic and commodity price indicators for 2010 and beyond reflect continued improvement in the economic environment. However, given the potential volatility of these measures, it is reasonably possible that the economy and/or commodity prices could decline, negatively impacting future operating results and increasing the risk of nonperformance of counterparties or impairments of goodwill and long-lived assets.

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 our gathering and processing and interstate natural gas pipeline systems;
- Continuing to invest in our natural gas production development, although at a lower level than in recent years;
- Retaining the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions, as well as seizing attractive opportunities.

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

- Lower than anticipated 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 drilling success or abandonment of projects by third parties served by Midstream and Gas Pipeline;
- Additional general economic, financial markets, or industry downturn;
- Changes in the political and regulatory environments;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 12 of Notes to Consolidated Financial Statements).

Management s Discussion and Analysis (Continued)

We continue to address these risks through utilization of commodity hedging strategies, focused efforts to resolve regulatory issues and litigation claims, disciplined investment strategies, and maintaining at least $1 billion in liquidity from cash and cash equivalents and unused revolving credit facilities. In addition, we utilize master netting agreements and collateral requirements with our counterparties.

Overview of Nine Months Ended September 30, 2009

Income from continuing operations attributable to The Williams Companies, Inc., for the nine months ended September 30, 2009, decreased by $917 million compared to the nine months ended September 30, 2008. This decrease is reflective of:

- The overall unfavorable commodity price environment in the first nine months of 2009 as compared to 2008;
- The absence of a $148 million pre-tax gain recorded in the first nine months of 2008 associated with the sale of Exploration & Production s Peru interests.
- A $75 million pre-tax impairment charge in the first quarter of 2009 related to Midstream s Venezuelan investment in 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 nine months ended September 30, 2009, decreased $848 million compared to the nine months ended September 30, 2008, primarily due to the decrease in our operating results. See additional discussion in Management s Discussion and Analysis of Financial Condition and Liquidity.

Recent Events

In March 2009, we issued $600 million aggregate principal amount of 8.75 percent senior unsecured notes due 2020 to certain institutional investors in a private debt placement. In August 2009, we completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

In April 2009, Midstream announced its plan to build a 261-mile natural gas liquid pipeline in Canada at an estimated cost of $283 million. Construction is expected to begin in 2010 with completion expected in 2012.

In May 2009, certain of Midstream s Venezuela operations were expropriated by the Venezuelan government. As a result, these operations are now reflected as discontinued operations and have been deconsolidated. (See Note 3 of Notes to Consolidated Financial Statements.)

In June 2009, Midstream finalized the formation of a new joint venture in the Marcellus Shale located in southwest Pennsylvania. (See Results of Operations Segments, Midstream Gas & Liquids).

In June 2009, Exploration & Production entered into an agreement to develop properties in the Marcellus Shale. (See Results of Operations Segments, Exploration & Production.)

In September 2009, Exploration & Production completed the purchase of additional properties in the Piceance basin of Colorado for $255 million. (See Results of Operations Segments, Exploration & Production.)

In September 2009, Gas Pipeline received approval from the FERC to begin construction of the 85 North expansion project at an estimated cost of $241 million. (See Results of Operations Segments, Gas Pipeline.)

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 included in Item 1 of this document and our annual consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated August 27, 2009.

Fair Value Measurements

Certain of our energy derivative assets and liabilities and other assets 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 September 30, 2009, less than 1 percent of the total assets and total 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.

As of September 30, 2009, Level 2 includes option contracts that hedge future sales of production from our Exploration & Production segment; these options are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Prior to the third quarter of 2009, these options were included in Level 3 as a significant input to the model, implied volatility by location, was considered unobservable. However, due to increased transparency over the past several quarters, we now consider this input to be observable and have included these options in Level 2.

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 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. 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 September 30, 2009, the credit reserve is less than $1 million on our net derivative assets and $4 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.

As of September 30, 2009, 85 percent of our derivatives portfolio expires in the next 12 months and more than 99 percent of our derivatives portfolio 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 September 30, 2009, consist of natural gas liquids swaps for our Midstream segment as well as natural gas index transactions that are used to manage the physical requirements of our Exploration & Production segment and our Midstream 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 2013 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 nine months ended September 30, 2009, we have recognized impairments of certain assets that have been measured at fair value on a nonrecurring basis. These impairment measurements are included within 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.)

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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 nine months ended September 30, 2009, compared to the three and nine months ended September 30, 2008. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended September 30,				Nine months ended September 30,			
	2009	2008	$ Change*	% Change*	2009	2008	$ Change*	% Change*
	(Millions)				(Millions)			
Revenues	$ 2,098	$ 3,201	-1,103	-34%	$ 5,929	$ 10,022	-4,093	-41%
Costs and expenses:								
Costs and operating expenses	1,537	2,344	+807	+34%	4,373	7,374	+3,001	+41%
Selling, general and administrative expenses	126	133	+7	+5%	380	375	-5	-1%
Other (income) expense net	1	1			33	(145)	-178	NM
General corporate expenses	40	34	-6	-18%	118	118		
Total costs and expenses	1,704	2,512			4,904	7,722		
Operating income	394	689			1,025	2,300		
Interest accrued net	(153)	(146)	-7	-5%	(440)	(443)	+3	+1%
Investing income	39	65	-26	-40%	2	174	-172	-99%
Other income (expense) net	(1)	2	-3	NM	(2)	6	-8	NM
Income from continuing operations before income taxes	279	610			585	2,037		
Provision for income taxes	87	199	+112	+56%	223	707	+484	+68%
Income from continuing operations	192	411			362	1,330		
Income (loss) from discontinued operations	2	10	-8	-80%	(223)	130	-353	NM
Net income	194	421			139	1,460		

Less: Net income attributable to noncontrolling interests	51	55	+4	+7%	26	157	+131	+83%
Net income attributable to The Williams Companies, Inc.	$ 143	$ 366			$ 113	$ 1,303		

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

Three months ended September 30, 2009 vs. three months ended September 30, 2008

The decrease in *revenues* is primarily due to decreased realized revenue at Gas Marketing primarily reflecting a decrease in average natural gas prices as well as lower NGL and olefin production revenues, and lower NGL, olefin and crude marketing revenues at Midstream. In addition, Exploration & Production revenues decreased primarily due to lower net realized average prices, partially offset by higher production volumes sold.

The decrease in *costs and operating expenses* is primarily due to decreased costs at Gas Marketing primarily reflecting a decrease in average natural gas prices as well as decreased costs associated with our olefin production business, NGL, olefin and crude marketing purchases and decreased costs associated with our NGL production business at Midstream.

Other (income) expense net within *operating income* in 2008 includes a $14 million impairment of certain natural gas producing properties at Exploration & Production, partially offset by a gain of $10 million on the sale of certain south Texas assets at Gas Pipeline and $7 million of net gains on foreign currency exchanges at Midstream.

The decrease in *operating income* reflects an overall unfavorable energy commodity price environment in the third quarter of 2009 compared to the same period in 2008.

The unfavorable change in *investing income* is primarily due to lower equity earnings and a decrease in interest income largely resulting from lower average interest rates in 2009 compared to 2008.

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.

Management s Discussion and Analysis (Continued)

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

Nine months ended September 30, 2009 vs. nine months ended September 30, 2008

The decrease in *revenues* is primarily due to decreased realized revenue at Gas Marketing primarily reflecting a decrease in average natural gas prices as well as lower NGL, olefin and crude marketing revenues and lower NGL and olefin production revenues at Midstream. In addition, Exploration & Production revenues decreased primarily due to lower net realized average prices, partially offset by higher production volumes sold.

The decrease in *costs and operating expenses* is primarily due to decreased costs at Gas Marketing primarily reflecting a decrease in average natural gas prices as well as decreased NGL, olefin and crude marketing purchases and decreased costs associated with our olefin and NGL production businesses at Midstream.

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.

Other (income) expense net within *operating income* in 2008 includes a gain of $148 million on the sale of our Peru interests at Exploration & Production, $13 million of net gains on foreign currency exchanges at Midstream, and a gain of $10 million on the sale of certain south Texas assets at Gas Pipeline. These items are partially offset by $21 million of project development costs at Gas Pipeline and a $14 million impairment of certain natural gas producing properties at Exploration & Production.

The decrease in *operating income* reflects an overall unfavorable energy commodity price environment in the first nine months of 2009 compared to the first nine months of 2008, the absence of a $148 million gain on the sale of our Peru interests at Exploration & Production in 2008, and other changes as discussed previously.

Interest accrued net decreased primarily due to an increase in capitalized interest resulting from ongoing construction projects at Midstream, partially offset by higher interest expense primarily associated with our March 2009 debt issuance.

The unfavorable change in *investing income* is due primarily to a $75 million impairment of Midstream s Accroven investment and an $11 million impairment of a cost-based investment at Exploration & Production. (See Note 4 of Notes to Consolidated Financial Statements.) A decrease in equity earnings, primarily at Midstream, and a decrease in interest income, primarily due to lower average interest rates in 2009 compared to 2008, also contributed to the unfavorable change in *investing income.*

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*.

Net income attributable to noncontrolling interests decreased reflecting the first-quarter 2009 impairments and related charges associated with Midstream s discontinued Venezuela operations (see Note 3 of Notes to Consolidated Financial Statements) and the decline in Williams Partners L.P. s operating results primarily driven by lower NGL margins.

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Management s Discussion and Analysis (Continued)

Results of Operations Segments

Exploration & Production

Overview of Nine Months Ended September 30, 2009

Segment revenues and segment profit for the first nine months of 2009 were significantly lower than the first nine months of 2008 primarily due to a sharp decline in net realized average prices partially offset by higher production volumes. Additionally, the first nine months of 2009 include expense of $32 million associated with contractual penalties from the early termination of drilling rig contracts. The first nine months of 2008 include a $148 million gain on sale of our Peru interests. Highlights of the comparative periods include:

	For the nine months ended September 30,		
	2009	2008	% Change
Average daily domestic production (MMcfe) (1)	1,184	1,073	+10%
Average daily total production (MMcfe)	1,237	1,122	+10%
Domestic net realized average price ($/Mcfe) (2)	$ 4.11	$ 7.22	-43%
Capital expenditures incurred ($ millions)	$1,004	$1,902	-47%
Segment revenues ($ millions)	$1,605	$2,537	-37%
Segment profit ($ millions)	$ 303	$1,287	-76%

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

(2) Mcfe is equal to one thousand cubic feet of gas equivalent.

The increased production is primarily within the Piceance, Powder River, and Fort Worth basins. As previously discussed in Company Outlook, we have reduced development activities and related capital expenditures in 2009 which has resulted in production peaking during the first quarter of 2009, then decreasing slightly thereafter.

Net realized average prices include market prices, net of fuel and shrink and hedge gains and losses, less gathering and transportation expenses.

Significant events

In June 2009, we entered into an agreement that allows us to acquire, through a drill to earn structure, a 50 percent interest in approximately 44,000 net acres in Pennsylvania s Marcellus Shale. This agreement requires us to fund $33 million of drilling and completion costs on behalf of our partner and $41 million of our own costs and expenses prior to the end of 2011 to earn our 50 percent interest. This growth opportunity leverages our experience in developing non-conventional natural gas reserves.

In September 2009, we completed the purchase of additional unproved leasehold acreage and proved properties in the Piceance basin for $255 million, subject to post closing adjustments.

Outlook for the Remainder of 2009

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

A reduced development drilling program, as compared to the prior year, in the Piceance, Powder River, San Juan and Fort Worth basins. Our remaining capital expenditures for 2009 are projected to be between

$221 million and $321 million, which is reflective of a reduction in drilling rigs deployed and any additional capital expenditures to be incurred in 2009 in Marcellus Shale and Piceance as a result of the previously described agreement and acquisition.

Modest growth in our annual average daily domestic production level compared to 2008, although fourth quarter 2009 volumes are likely to be less than fourth quarter 2008 volumes. As previously discussed, average daily domestic production peaked during the first quarter of 2009.

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Management s Discussion and Analysis (Continued)

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 the condition of the global economy. A further decline in natural gas prices could 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. For example, the Colorado Oil & Gas Conservation Commission has enacted new rules effective in April 2009 which have increased our costs of permitting and environmental compliance and could potentially delay drilling permits. The new rules include additional environmental and operational requirements as part of permit approvals, tracking of certain chemicals brought on location, increased wildlife stipulations, new pit and waste management procedures and increased notifications and approvals from surface landowners. Our current outlook incorporates these changes; however, the extent and magnitude of these changes could be greater than our current assumptions.

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 2009, we have the following contracts for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

		Remainder of 2009	
		Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Collars	Rockies	150	$ 6.11 - $9.04
Collars	San Juan	245	$ 6.58 - $9.62
Collars	Mid-Continent	95	$ 7.08 - $9.73
NYMEX and basis fixed-price		106	$3.92

The following is a summary of our contracts for daily production for the three and nine months ended September 30, 2009 and 2008:

		2009		2008	
		Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Third Quarter:					
Collars	Rockies	150	$ 6.11 - $9.04	160	$ 6.08 - $9.04
Collars	San Juan	245	$ 6.58 - $9.62	220	$ 6.37 - $9.00
Collars	Mid-Continent	95	$ 7.08 - $9.73	80	$ 7.02 - $9.77
NYMEX and basis fixed-price		106	$3.59	70	$3.90
Year-to-Date:					
Collars	Rockies	150	$ 6.11 - $9.04	173	$ 6.18 - $9.18
Collars	San Juan	245	$ 6.58- $9.62	196	$ 6.34 - $8.94
Collars	Mid-Continent	95	$ 7.08 - $9.73	57	$ 7.03 - $9.71
NYMEX and basis fixed-price		106	$3.59	70	$3.94

Additionally, we utilize contracted pipeline capacity through Gas Marketing Services to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We also expect additional pipeline capacity to be put into service in late 2009 which will transport gas into the Midwest.

Period-Over-Period Results

	Three months ended	Nine months ended

	September 30,		September 30,	
	2009	2008	2009	2008
	(Millions)		(Millions)	
Segment revenues	$ 522	$ 861	$ 1,605	$ 2,537
Segment profit	$ 106	$ 361	$ 303	$ 1,287

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Management s Discussion and Analysis (Continued)

Three months ended September 30, 2009 vs. three months ended September 30, 2008

Total *segment revenues* decreased $339 million, or 39 percent, primarily due to the following:

- $252 million, or 34 percent, decrease in domestic production revenues reflecting $287 million associated with a 40 percent decrease in net realized average prices, partially offset by an increase of $35 million associated with a 5 percent increase in production volumes sold. Production revenues in 2009 and 2008 include approximately $22 million and $32 million, respectively, related to natural gas liquids and approximately $11 million and $25 million, respectively, related to condensate;

- $57 million decrease primarily reflecting lower average sales prices for gas management activities related to gas sold on behalf of certain outside parties, which is offset by a similar decrease in *segment costs and expenses*;

- $19 million unfavorable change related to hedge ineffectiveness due to $1 million in net realized losses from hedge ineffectiveness in 2009 compared to $18 million in net realized gains in 2008.

Total *segment costs and expenses* decreased $85 million, primarily due to the following:

- $51 million decrease primarily reflecting lower average sales prices for gas management activities related to gas purchased on behalf of certain outside parties, which is offset by a similar decrease in *segment revenues*;

- $46 million lower operating taxes due primarily to 61 percent lower average market prices (excluding the impact of hedges), partially offset by higher production volumes sold;

- $14 million decrease due to the absence in 2009 of an impairment recorded in the third quarter of 2008;

- $10 million decrease in lease and other operating expenses primarily due to reduced costs throughout the industry.

Partially offsetting the decreased costs is:

- $30 million of higher depreciation, depletion and amortization expense primarily due to higher capitalized drilling costs and higher production volumes compared to the prior year;

- $9 million increase in gathering fees primarily related to higher production volumes and the processing fees for natural gas liquids at the Willow Creek plant, which began processing in August 2009.

The $255 million decrease in s*egment profit* is primarily due to the 40 percent decrease in net realized average domestic prices and the other previously discussed changes in *segment revenues* and *segment costs and expenses.*

Nine months ended September 30, 2009 vs. nine months ended September 30, 2008

Total *segment revenues* decreased $932 million, or 37 percent, primarily due to the following:

- $776 million, or 35 percent, decrease in domestic production revenues reflecting $995 million associated with a 43 percent decrease in net realized average prices, partially offset by an increase of $219 million associated with a 10 percent increase in production volumes sold. Production revenues in 2009 and 2008 include approximately $45 million and $75 million, respectively, related to natural gas liquids and approximately $25 million and $60 million, respectively, related to condensate;

- $153 million decrease primarily reflecting lower average sales prices for gas management activities related to gas sold on behalf of certain outside parties, which is offset by a similar decrease in *segment costs and expenses.*

Management s Discussion and Analysis (Continued)

Total *segment costs and expenses* increased $50 million, primarily due to the following:

- The absence of a $148 million gain recorded in 2008 associated with the sale of our Peru interests;
- $118 million higher depreciation, depletion and amortization expense primarily due to higher capitalized drilling costs and higher production volumes compared to the prior year;
- $32 million of expense related to penalties from the early release of rigs as previously discussed;
- $32 million higher exploratory expense in 2009, primarily related to seismic costs;
- $18 million higher gathering fees primarily due to higher production volumes and the processing fees for natural gas liquids at the Willow Creek plant, which began processing in August 2009.

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

- $150 million decrease primarily reflecting lower average sales prices for gas management activities related to gas purchased on behalf of certain outside parties, which is offset by a similar decrease in *segment revenues*;
- $133 million lower operating taxes due primarily to 63 percent lower average market prices (excluding the impact of hedges), partially offset by higher production volumes sold;
- $14 million due primarily to the absence in 2009 of an impairment recorded in the third quarter of 2008.

The $984 million decrease in s*egment profit* is primarily due to the 43 percent decrease in net realized average domestic prices and the other previously discussed changes in *segment revenues* and *segment costs and expenses.*

Gas Pipeline

Overview of Nine Months Ended September 30, 2009

Gulfstream Phase IV expansion project

In September 2007, our 50 percent-owned equity investee, Gulfstream Natural Gas System, L.L.C. (Gulfstream), received FERC approval to construct 17.8 miles of 20-inch pipeline and to install a new compressor facility. The pipeline expansion was placed into service in the fourth quarter of 2008, and the compressor facility was placed into service in January 2009. The expansion increased capacity by 155 thousand dekatherms per day (Mdt/d). Gulfstream s estimated cost of this project is $190 million.

85 North expansion project

In September 2009, we received approval from the FERC to construct 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 is anticipated to begin in July 2010 and will increase capacity by 90 Mdt/d. Phase II service is anticipated to begin in May 2011 and will increase capacity by 218 Mdt/d.

Mobile Bay South expansion project

In May 2009, we received approval from the FERC to construct a compression facility in Alabama allowing transportation service to various southbound delivery points. The cost of the project is estimated to be $37 million. The estimated project in-service date is May 2010 and will increase capacity by 253 Mdt/d.

Management s Discussion and Analysis (Continued)

Sundance Trail expansion project

In May 2009, we filed an application with the FERC to construct approximately 16 miles of 30-inch pipeline between our existing compressor stations in Wyoming. The project also includes an upgrade to our existing compressor station and is estimated to cost $65 million. The estimated in-service date is November 2010 and will increase capacity by 150 Mdt/d.

Williams Pipeline Partners L.P.

We own approximately 47.7 percent of Williams Pipeline Partners L.P., including 100 percent of the general partner and incentive distribution rights. Considering the presumption of control of the general partner, Williams Pipeline Partners L.P. is consolidated within our Gas Pipeline segment. Gas Pipeline s segment profit includes 100 percent of Williams Pipeline Partners L.P. s segment profit.

Outlook for the Remainder of 2009

Sentinel expansion project

In August 2008, we received FERC approval to construct an expansion in the northeast United States. The cost of the project is estimated to be $229 million. We placed Phase I into service in December 2008 increasing capacity by 40 Mdt/d. Phase II will provide an additional 102 Mdt/d and is expected to be placed into service in November 2009.

Colorado Hub Connection project

In April 2009, we received approval from the FERC and began construction in June 2009 of a 27-mile pipeline to provide increased access to the Rockies natural gas supplies. The estimated cost of the project is $60 million with service targeted to commence in November 2009. We will combine the lateral capacity with existing mainline capacity to provide approximately 363 Mdt/d of firm transportation from various receipt points for delivery to Ignacio, Colorado.

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(Millions)		(Millions)	
Segment revenues	$ 379	$ 407	$ 1,201	$ 1,226
Segment profit	$ 157	$ 173	$ 498	$ 532

Three months ended September 30, 2009 vs. three months ended September 30, 2008

Segment revenues decreased primarily due to a $25 million decrease in revenues from transportation imbalance settlements (offset in *costs and operating expenses*).

Costs and operating expenses decreased $14 million, or 7 percent, primarily due to a $25 million decrease associated with transportation imbalance settlements (offset in *segment revenues*), partially offset by a $6 million increase in transportation-related fuel expense resulting from less favorable recovery from customers due to pricing differences and a $4 million increase in depreciation expense.

Other (income) expense net reflects the absence of a $10 million gain on the sale of certain south Texas assets in third-quarter 2008 by Transco, substantially offset by $9 million lower project development costs in 2009.

Segment profit decreased primarily due to the previously described changes.

Nine months ended September 30, 2009 vs. nine months ended September 30, 2008

Segment revenues decreased primarily due to a $31 million decrease in revenues from transportation imbalance settlements (offset in *costs and operating expenses*), partially offset by a $15 million increase in other service revenues.

Management s Discussion and Analysis (Continued)

Costs and operating expenses increased $5 million, or 1 percent, primarily due to a $13 million increase in transportation-related fuel expense resulting from less favorable recovery from customers due to pricing differences, a $12 million increase in depreciation expense, and $8 million higher employee-related expenses. These increases were partially offset by a $31 million decrease in costs associated with transportation imbalance settlements (offset in *segment revenues*).

Selling, general and administrative expenses increased $4 million, or 3 percent, primarily due to an increase in pension expense. We expect the higher pension costs to continue throughout 2009.

Other (income) expense net reflects the absence of a $10 million gain on the sale of certain south Texas assets in third-quarter 2008 by Transco and a $9 million gain recorded in second-quarter 2008 on the sale of excess inventory gas. Partially offsetting these unfavorable changes is $16 million lower project development costs in 2009.

Segment profit decreased primarily due to the previously described changes.

Midstream Gas & Liquids

Overview of Nine Months Ended September 30, 2009

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

Significant events during 2009 include the following:

Willow Creek

The Willow Creek facility in western Colorado began processing Exploration & Production s natural gas production and extracting NGLs in early August and achieved full processing operations in September. The 450-million-cubic-feet-per-day (MMcfd) gas processing plant has a peak capacity of 30,000 barrels per day and is currently recovering up to 20,000 barrels per day of NGLs. In the processing arrangement with Exploration & Production, Midstream receives a volumetric-based processing fee and a percent of the NGLs extracted.

Laurel Mountain Midstream, LLC

In June 2009, we completed the formation of a new joint venture in the Marcellus Shale located in southwest Pennsylvania. Our partner in the venture contributed its existing Appalachian Basin gathering system, which includes approximately 1,800 miles of intrastate natural gas gathering lines servicing 6,900 wells. The system currently has an average throughput in excess of 100 MMcf/d. In exchange for a 51 percent interest, we contributed $100 million and issued a $26 million note payable. We account for this investment under the equity method due to the significant participatory rights of our partner such that we do not control the investment. We continue the process of transitioning operational control from our partner to us and evaluating growth opportunities.

Venezuela

In May 2009, the Venezuelan government expropriated the El Furrial and PIGAP II assets that we operated in Venezuela. As a result, these operations are now reflected as discontinued operations for all periods presented and are no longer included in Midstream s results. Our investment in Accroven, whose assets have not been expropriated, is still included within Midstream and reflects a first-quarter 2009 impairment charge of $75 million. (See Notes 3 and 4 of Notes to Consolidated Financial Statements for further discussion.)

Volatile commodity prices

Average NGL and natural gas prices, along with most other energy commodities, continue to be impacted by the weakened economy. NGL prices, especially ethane prices, as well as natural gas prices, were significantly lower in the nine months ended September 30, 2009, compared to the same period in 2008. While NGL margins in the third

quarter of 2009 are still significantly lower than the same period in 2008, they have improved since the first and second quarters of 2009. During 2009, natural gas prices have declined significantly and beginning in the second quarter of 2009, NGL prices, especially ethane, have increased. We continue to benefit from favorable natural gas price differentials in the Rocky Mountain area, although the differentials have narrowed during 2009 along with the overall reduction in gas prices. These differentials contributed to realized per-unit margins that were generally 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 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.

Hurricane Ike

As a result of Hurricane Ike in September 2008, our Cameron Meadows NGL processing plant sustained significant damage, and operations were temporarily suspended. We have rebuilt a portion of the Cameron plant and operations resumed in the third quarter of 2009. In October 2009 we signed an agreement, subject to certain additional approvals, for the sale of our Cameron Meadows plant. We expect the sales price will exceed our net book value and result in a pretax gain in the fourth quarter of 2009.

While our insurance expense has increased modestly in 2009 compared to 2008, the overall level of coverage on our offshore assets in the Gulf Coast region against named windstorm events has substantially decreased, including the absence of coverage on certain of our assets. (See Note 13 of Notes to Consolidated Financial Statements.)

Williams Partners L.P.

We own approximately 23.6 percent of Williams Partners L.P., including 100 percent of the general partner and incentive distribution rights. Considering the presumption of control of the general partner, Williams Partners L.P. is consolidated within the Midstream segment. (See Note 2 of Notes to Consolidated Financial Statements.) Midstream s segment profit includes 100 percent of Williams Partners L.P. s segment profit.

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Management s Discussion and Analysis (Continued)

Outlook for the Remainder of 2009

The following factors could impact our business in 2009.

Commodity price changes

NGL, crude and natural gas prices are highly volatile. NGL price changes have historically tracked with changes in the price of crude oil. We expect per-unit margins in the fourth quarter of 2009 to be slightly higher than our rolling five-year average per-unit margins.

Margins in our NGL and olefins business are highly dependent upon continued demand within the global economy. NGL products are currently the preferred feedstock for ethylene and propylene production, which are the building blocks of polyethylene or plastics. Although forecasted domestic and global demand for polyethylene has been impacted by the current weakness in the global economy, propylene and ethylene production processes have increasingly shifted from the more expensive crude-based feedstocks to NGL-based feedstocks. Bolstered by abundant long-term domestic natural gas supplies, we expect to benefit from these dynamics in the broader global petrochemical markets.

In our olefin production business, we anticipate margins for the fourth quarter of 2009 to approximate third-quarter 2009 levels.

To reduce the exposure to changes in market prices, we have entered into NGL swap agreements to fix the prices of a portion of our anticipated NGL sales for the remainder of 2009. As part of our efforts to manage commodity price risks on an enterprise basis, we continue to evaluate our commodity hedging strategies.

Gathering and processing volumes

The growth of onshore natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities. The current commodity price environment would indicate a reduction in certain producer drilling activities. Our customers in the West region are generally large producers and we have not experienced and do not anticipate an overall dramatic decline in drilling activity.

In the West, we expect higher fee revenues, NGL volumes, depreciation expense and operating expenses in the fourth quarter of 2009 compared to the third quarter of 2009 as our Willow Creek facility moves into a full quarter of operation.

We expect fee revenues, depreciation expense, and operating expenses in our offshore Gulf Coast region in the fourth quarter of 2009 to approximate third-quarter 2009 levels. Increases from our Devils Tower infrastructure expansions serving the Blind Faith and Bass Lite prospects are expected to be partially offset by lower volumes in other Gulf Coast areas due to expected natural declines.

Allocation of capital to expansion projects

We expect to spend $420 million in 2009 on our major expansion projects, of which approximately $130 million remains to be spent. The ongoing commitments related to our major expansion projects include:

The Perdido Norte project, in the western deepwater of the Gulf of Mexico, which will include an expansion of our Markham gas processing facility and oil and gas lines that will expand the scale of our existing infrastructure. Significant milestones have been reached and, considering the progress of our customer s drilling and tie-in construction, we expect this project to begin contributing to our segment profit in early 2010.

Additional processing and NGL production capacities at our Echo Springs facility, in the Wamsutter area of Wyoming, which we expect to be in service at the end of 2010.

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Management s Discussion and Analysis (Continued)

Other factors for consideration

The current economic and commodity price environment may cause financial difficulties for certain of our customers. Many of our marketing counterparties are in the petrochemicals industry, which has been under severe stress from the current economic conditions. Although we actively manage our credit exposure through certain collateral or payment terms and arrangements, continued economic weakness may result in significant credit or bad debt losses.

We expect continued savings in certain NGL transportation costs in the West region due to the transition from our previous shipping arrangement to transportation on the Overland Pass pipeline. NGL volumes from our Wyoming plants began to flow into the Overland Pass pipeline in the fourth quarter of 2008, relieving pipeline capacity constraints and resulting in an expected increase in NGL volumes for 2009.

Period-Over-Period Operating Results

	Three months ended September 30,		Nine Months ended September 30,	
	2009	2008	2009	2008
	(Millions)		(Millions)	
Segment revenues	$ 991	$ 1,392	$ 2,489	$ 4,619
Segment profit (loss):				
Domestic gathering & processing	$ 186	$ 225	$ 393	$ 661
NGL marketing, olefins, and other	58	23	111	139
Venezuela		5	(68)	11
Indirect general and administrative expense	(22)	(24)	(65)	(74)
Total	$ 222	$ 229	$ 371	$ 737

In order to provide additional clarity, our management s discussion and analysis of operating results separately reflects the portion of general and administrative expense not allocated to an asset group as *indirect general and administrative expense*. These charges represent any overhead cost not directly attributable to one of the specific asset groups noted in this discussion.

Three months ended September 30, 2009 vs. three months ended September 30, 2008

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

A $180 million decrease in revenues associated with the production of NGLs primarily due to lower average NGL prices, partially offset by higher volumes.

A $135 million decrease in revenues in our olefins production business primarily due to lower average product prices, partially offset by higher volumes.

A $102 million decrease in NGL, olefin and crude marketing revenues primarily due to lower average NGL and crude prices, partially offset by higher volumes.

These decreases are partially offset by a $20 million increase in fee revenues primarily due to higher volumes resulting from connecting new supplies in the deepwater Gulf of Mexico in the latter part of 2008 and new fees for processing Exploration & Production s natural gas production at Willow Creek.

Segment costs and expenses decreased $401 million, or 34 percent, primarily as a result of:

A $147 million decrease in costs in our olefins production business primarily due to lower per-unit feedstock costs, partially offset by higher volumes.

A $137 million decrease in NGL, olefin and crude marketing purchases primarily due to lower average NGL and crude prices, partially offset by higher volumes.

A $121 million decrease in costs associated with the production of NGLs primarily due to lower average natural gas prices, partially offset by higher volumes.

Management s Discussion and Analysis (Continued)

These decreases are partially offset by the absence of an $8 million gain recognized in 2008 related to a final earn- out payment on a 2005 asset sale.

The decrease in Midstream s *segment profit* reflects the previously described changes in *segment revenues* and *segment costs and expenses.*

A more detailed analysis of the segment profit of certain Midstream operations is presented as follows.

Domestic gathering & processing

The decrease in *domestic gathering & processing segment profit* includes a $35 million decrease in the West region and a $4 million decrease in the Gulf Coast region.

The decrease in our West region s *segment profit* includes:

- A $43 million decrease in NGL margins due to a significant decrease in average NGL prices, partially offset by a significant decrease in production costs reflecting lower natural gas prices, and an increase in volumes sold. NGL equity sales volumes are favorable compared to unusually low volumes in the third quarter of 2008, primarily due to lower ethane recoveries to accommodate restrictions on the volume of NGLs we could deliver into third-party pipelines caused by a lack of capacity, and to hurricane-related disruptions at a third-party fractionation facility at Mont Belvieu, Texas, which resulted in an NGL inventory build-up. While volumes are higher overall, NGL equity sales volumes were unfavorably impacted when certain producers elected to convert, in accordance with those gas processing agreements, from keep-whole to fee-based processing at the beginning of 2009. Lower NGL transportation costs in the West region due to the transition from our previous shipping arrangement to transportation on the Overland Pass pipeline also favorably impacted NGL margins in 2009.
- An $11 million increase in fee revenues due primarily to new fees for processing Exploration & Production s natural gas production at Willow Creek.

The decrease in the Gulf Coast region s *segment profit* includes:

- A $16 million decrease in NGL margins reflecting lower average NGL prices, partially offset by lower production costs reflecting lower natural gas prices. NGL volumes are comparable in both periods reflecting favorable changes related to downtime and reduced volumes associated with hurricanes in the third quarter of 2008, offset by natural declines in production sources.
- A $13 million increase in fee revenues primarily due to higher volumes resulting from connecting new supplies in the Blind Faith and Bass Lite prospects in the deepwater in the latter part of 2008.

NGL marketing, olefins and other

The significant components of the increase in *segment profit* of our other operations include:

- $32 million in higher margins related to the marketing of NGLs and olefins due primarily to favorable changes in pricing while product was in transit during 2009 as compared to unfavorable changes in pricing in 2008 and the absence of a $14 million charge in 2008 relating to a lower-of-cost-or-market adjustment on NGL inventories.

- $12 million in higher margins in our olefins production business primarily due to higher volumes in 2009 related to the impact of third-party operational issues in 2008 that reduced off-gas supplies to our plant in Canada.

- An $11 million unfavorable change in foreign exchange gains and losses related to the revaluation of current assets held in U.S. dollars within our Canadian operations consisting of $3 million of losses in 2009, compared to $8 million of gains in 2008.

- A $11 million decrease in operating costs including the absence of hurricane repairs and property insurance deductibles in 2008 at our facility at Geismar.

Management s Discussion and Analysis (Continued)

The absence of an $8 million gain recognized in 2008 related to a final earn-out payment on a 2005 asset sale.

Nine Months ended September 30, 2009 vs. Nine Months ended September 30, 2008

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

A $927 million decrease in NGL, olefin and crude marketing revenues primarily due to lower average NGL and crude prices.

A $714 million decrease in revenues associated with the production of NGLs primarily due to lower average NGL prices.

A $500 million decrease in revenues in our olefins production business primarily due to lower average product prices, partially offset by higher volumes.

These decreases are partially offset by a $42 million increase in fee revenues primarily due to higher volumes resulting from connecting new supplies in the deepwater Gulf of Mexico in the latter part of 2008.

Segment costs and expenses decreased $1,874 million, or 47 percent, primarily as a result of:

A $970 million decrease in NGL, olefin and crude marketing purchases primarily due to lower average NGL and crude prices.

A $467 million decrease in costs in our olefins production business primarily due to lower per-unit feedstock costs, partially offset by higher volumes.

A $433 million decrease in costs associated with the production of NGLs primarily due to lower average natural gas prices.

The decrease in Midstream s *segment profit* reflects the previously described changes in *segment revenues* and *segment costs and expenses,* a $75 million loss from investment related to the impairment of our investment in Accroven, and lower equity earnings, primarily related to a $19 million decrease from Discovery Producer Services, LLC, and a $13 million decrease from Aux Sable Liquid Products, LP, both of which are primarily due to lower processing margins.

A more detailed analysis of the segment profit of certain Midstream operations is presented as follows.

Domestic gathering & processing

The decrease in *domestic gathering & processing segment profit* includes a $186 million decrease in the West region and an $82 million decrease in the Gulf Coast region.

The decrease in our West region s *segment profit* includes:

A $191 million decrease in NGL margins and an $8 million decrease in condensate margins due to a significant decrease in average NGL and condensate prices, partially offset by a significant decrease in production costs reflecting lower natural gas prices. NGL equity volumes were slightly higher as both periods were impacted by significant volume changes. Current year volumes include the unfavorable impact of certain producers electing to convert, in accordance with those gas processing agreements, from keep-whole to fee-based processing at the beginning of 2009. Prior year NGL equity volumes sold were unusually low primarily due to an increase in inventory as we transitioned from product sales at the plant to shipping volumes through a pipeline for sale downstream, lower ethane recoveries to accommodate restrictions on the volume of NGLs we could deliver into the pipelines and hurricane-related disruptions at a third-party fractionation facility at Mont Belvieu, Texas which resulted in an NGL inventory build-up. Lower NGL transportation costs in the West region due to the transition from our previous shipping arrangement to transportation on the Overland Pass pipeline also favorably impacted NGL margins in 2009.

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Management s Discussion and Analysis (Continued)

A $24 million increase in fee revenues primarily due to new fees for processing Exploration & Production s natural gas production at Willow Creek, unusually low gathering and processing volumes in the first quarter of 2008 related to severe winter weather conditions, and producers converting from keep-whole to fee-based processing in the first quarter of 2009.

The decrease in the Gulf Coast region s *segment profit* includes:

A $90 million decrease in NGL margins reflecting lower average NGL prices and lower volumes, primarily due to periods of reduced NGL recoveries during the first quarter of 2009 due to unfavorable NGL economics, and natural declines in production sources. Lower production costs reflecting lower natural gas prices partially offset these decreases.

$23 million higher fee revenues primarily due to higher volumes resulting from connecting new supplies in the Blind Faith prospect in the deepwater in the latter part of 2008.

A $17 million increase in depreciation primarily due to a $13 million increase related to our Blind Faith pipeline extensions that came into service during the latter part of 2008.

NGL marketing, olefins and other

The significant components of the decrease in *segment profit* of our other operations include:

$39 million in higher margins related to the marketing of NGLs and olefins due primarily to the absence of a $14 million charge in 2008 relating to a lower-of-cost-or-market adjustment on NGL inventories and favorable changes in pricing while product was in transit during 2009 as compared to unfavorable changes in 2008.

$33 million in lower margins in our olefins production business primarily due to lower average prices, partially offset by lower per-unit feedstock costs and higher volumes in 2009 related to the impact of third-party operational issues in 2008 that reduced off-gas supplies to our plant in Canada.

Lower equity earnings in Discovery Producer Services, LLC and Aux Sable Liquid Products, LP, as previously discussed.

A $20 million decrease in operating costs including the absence of hurricane repairs and property insurance deductibles in 2008 at our facility at Geismar.

A $14 million unfavorable change primarily due to the absence of $13 million of gains in 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations.

The absence of an $8 million gain recognized in 2008 related to a final earn-out payment on a 2005 asset sale.

Venezuela

The decrease in *segment profit* for our Venezuela operations primarily reflects the previously discussed $75 million loss from investment related to Accroven.

Gas Marketing Services

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring the majority of fuel and shrink gas and hedging natural gas liquids sales for Midstream. Gas Marketing also provides similar services to third parties, such as producers and processing companies. In addition, Gas Marketing manages various natural gas-related contracts such as transportation and storage, along with the

Management s Discussion and Analysis (Continued)

related hedges, including certain legacy natural gas contracts and positions. These legacy natural gas contracts and positions will expire in 2010.

Overview of Nine Months Ended September 30, 2009

Gas Marketing s operating results for the first nine months of 2009 are unfavorable compared to the first nine months of 2008 primarily due to lower realized margins on our storage contracts. This was partially offset by reduced net losses on proprietary trading and legacy contracts and reduced adjustments to the carrying value of our natural gas storage inventory.

Outlook for the Remainder of 2009

For the remainder of 2009, Gas Marketing will focus on providing services that support our natural gas businesses. Gas Marketing s earnings may continue to reflect mark-to-market volatility from commodity-based derivatives that represent economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting.

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(Millions)		(Millions)	
Realized revenues	$ 696	$ 1,687	$ 2,148	$ 5,363
Net forward unrealized mark-to-market gains	1	29	14	13
Segment revenues	$ 697	$ 1,716	$ 2,162	$ 5,376
Segment profit (loss)	$ (6)	$ 16	$ (14)	$ (9)

Three months ended September 30, 2009 vs. three months ended September 30, 2008

Realized revenues represent (1) revenue from the sale of natural gas or completion of gas-related services and (2) gains and losses from the net financial settlement of derivative contracts. *Realized revenues* decreased $991 million primarily due to a 62 percent decrease in average prices on physical natural gas sales, partially offset by a 11 percent increase in natural gas sales volumes. This decline in realized revenues is primarily related to both gas sales associated with our transportation contracts and gas sales associated with marketing Exploration & Production s gas volumes. These are offset by a similar decline in *segment costs and expenses.*

Net forward unrealized mark-to-market gains primarily represent changes in the fair values of certain derivative contracts with a future settlement or delivery date that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. The unfavorable change of $28 million is primarily the result of greater gas price increases in the third quarter of 2009 compared to the third quarter of 2008, which had an unfavorable impact on derivative contracts executed to economically hedge anticipated withdrawals of natural gas in storage.

Total *segment costs and expenses* decreased $997 million primarily due to a 62 percent decrease in average prices on physical natural gas purchases, partially offset by a 9 percent increase in natural gas purchase volumes. This decline is primarily related to the gas purchases associated with both our transportation contracts and gas purchases from Exploration & Production. The decline also reflects the absence in 2009 of a 2008 unfavorable adjustment of $24 million to the carrying value of our natural gas storage inventory.

The $22 million unfavorable change in *segment profit (loss)* is primarily due to unfavorable price movements on derivative contracts executed to economically hedge our natural gas storage activity and lower realized margins on storage contracts. These were partially offset by the absence of a 2008 unfavorable inventory adjustment.

Nine months ended September 30, 2009 vs. nine months ended September 30, 2008

Realized revenues decreased $3,215 million primarily due to a 62 percent decrease in average prices on physical natural gas sales, slightly offset by a 6 percent increase in natural gas sales volumes. This decline in realized revenues

is primarily related to both gas sales associated with our transportation contracts and gas sales associated with marketing Exploration & Production s gas volumes. This decline is offset by a similar decline in *segment costs*

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and expenses. The decline in *realized revenues* also includes a $45 million decrease associated with our storage contracts due primarily to declining prices.

The favorable change of $1 million in *net forward unrealized mark-to-market gains* is primarily the result of reduced net losses on proprietary and legacy contracts, partially offset by the absence of a $10 million favorable impact in 2008 due to considering our own nonperformance risk in estimating the fair value of our derivative liabilities.

Total *segment costs and expenses* decreased $3,209 million primarily due to a 62 percent decrease in average prices on physical natural gas purchases, slightly offset by a 6 percent increase in natural gas purchase volumes. This decline is primarily related to the previously discussed gas purchases associated with both our transportation contracts and gas purchases from Exploration & Production. The decline was partially offset by reduced unfavorable adjustments to the carrying value of our natural gas storage inventory. These adjustments totaled $7 million in 2009 compared to $32 million in 2008. Realized costs associated with our storage contracts were relatively comparable to the prior period.

The $5 million unfavorable change in *segment profit (loss)* is primarily due to a decline in realized margins on our storage contracts partially offset by reduced adjustments to the carrying value of our natural gas storage inventory and reduced net losses on proprietary trading and legacy contracts.

Other

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(Millions)		(Millions)	
Segment revenues	$ 6	$ 6	$ 20	$ 18
Segment profit (loss)	$ (1)	$ (2)	$ 3	$ (2)

The results of our Other segment are comparable to the prior year.

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Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition and Liquidity

Outlook

Operating results and cash flows for 2009 have been sharply reduced from 2008 levels due to the impact of lower energy commodity prices during the year. This impact has been, and will continue to be, somewhat mitigated by certain of our cash flow streams that are substantially insulated from sustained lower commodity prices, as follows:

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

Although the financial markets and energy commodity environment may continue to be depressed for the near term, 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 expectations for the remainder of the year and through 2010:

- We expect to maintain 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, and utilization of our revolving credit facilities as needed. We estimate our cash flow from operations will be between $2.1 billion and $2.3 billion for 2009. Based on a range of market assumptions, we currently estimate our cash flow from operations for 2010 will be between $2.15 billion and $2.9 billion.

We expect capital and investment expenditures to total $2.45 billion to $2.675 billion in 2009, with approximately $737 million to $962 million to be incurred over the remainder of the year. Of this total to be incurred over the remainder of the year, substantially all is considered nondiscretionary to meet legal, regulatory, and/or contractual requirements, to fund committed growth projects, or to preserve the value of existing assets. Included within the total estimated expenditures for 2009 is $225 million to $240 million for compliance and maintenance-related projects at Gas Pipeline. Based on a range of market assumptions, we currently expect capital and investment expenditures to total $1.9 billion to $2.675 billion in 2010, with approximately one-half considered nondiscretionary.

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;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 12 of Notes to Consolidated Financial Statements).

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 2009 and 2010. Our internal and external sources of 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. While most of our sources are available to us at the parent level, others may be available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. and

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Management s Discussion and Analysis (Continued)

Williams Pipeline Partners L.P., our master limited partnerships. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

In response to the challenges encountered by many financial institutions, the U.S. Government has provided substantial support to financial institutions, some of which are providers under our credit facilities. We continue to closely monitor the credit status of all providers under our credit facilities.

Available Liquidity

	Credit Facilities	
	Expiration	September 30, 2009 (Millions)
Cash and cash equivalents (1)		$ 1,640
Available capacity under our unsecured revolving and letter of credit facilities:		
$700 million facilities (2)	October 2010	478
$1.5 billion facility (3)	May 2012	1,430
Available capacity under Williams Partners L.P. s $200 million senior unsecured credit facility (4)	December 2012	188
		$ 3,736

(1) *Cash and cash equivalents* includes $1 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 $605 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.

(3) Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. We expect that the ability of both Northwest Pipeline and Transco to borrow under this facility is reduced by approximately $19 million each due to the bankruptcy of a participating bank. We also expect that our consolidated ability to borrow under this facility is reduced by a total of $70 million, including the reductions related to Northwest Pipeline and Transco. The available liquidity in the table above reflects this $70 million reduction. (See Note 9 of Notes to Consolidated Financial Statements.) The committed amounts of other participating banks remain in effect and are not impacted by this reduction.

The credit agreement governing this facility contains financial covenants including the requirement that we not exceed stated debt to capitalization ratios. At September 30, 2009, we are significantly below the maximum allowed ratios.

(4) This facility is only available to Williams Partners L.P. We expect that Williams Partners L.P. s ability to borrow under this facility is reduced by $12 million due to the bankruptcy of a participating bank. The available liquidity in the table above reflects this $12 million reduction. (See Note 9 of Notes to Consolidated Financial Statements.) The committed amounts of other participating banks remain in effect and are not impacted by this reduction.

The credit agreement governing this facility contains financial covenants related to Williams Partners L.P. s EBITDA to interest

expense ratio and indebtedness to EBITDA ratio (all as defined in the credit agreement). At September 30, 2009, Williams Partners L.P. is in compliance with these covenants and expects to remain in compliance with these covenants.

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Management s Discussion and Analysis (Continued)

Williams Pipeline Partners L.P. filed a shelf registration statement for the issuance of up to $1.5 billion aggregate principal amount of debt and limited partnership unit securities. The registration statement was declared effective on August 3, 2009.

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

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

Exploration & Production has an unsecured credit agreement with certain banks that, so long as certain conditions are met, serves to reduce our use of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. The agreement extends through December 2013.

Credit Ratings

Standard & Poor s rates our senior unsecured debt at BB+ and our corporate credit at BBB- with a stable ratings outlook. With respect to Standard & Poor s, a rating of BBB or above indicates an investment grade rating. A rating below BBB indicates that the security has significant speculative characteristics. A BB rating indicates that Standard & 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.

Moody s Investors Service rates our senior unsecured debt at Baa3 with a stable ratings outlook. With respect to Moody s, a rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. The 1 , 2 and 3 modifiers show the relative standing within a major category. A 1 indicates tha 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.

Fitch Ratings rates our senior unsecured debt at BBB- with a stable ratings outlook. With respect to Fitch, a rating of BBB or above indicates an investment grade rating. A rating below BBB is considered speculative grade. Fitch may add a + or a - sign to show the obligor s relative standing within a major rating category.

Credit rating agencies perform independent analyses when assigning credit ratings. No assurance can be given that the credit rating agencies will continue to assign us investment grade ratings even if we meet or exceed their current criteria for investment grade ratios. A downgrade of our credit rating might increase our future cost of borrowing and would require us to post additional collateral with third parties, negatively impacting our available liquidity. As of September 30, 2009, we estimate that a downgrade to a rating below investment grade would require us to post up to $469 million in additional collateral with third parties.

Sources (Uses) of Cash

	Nine months ended September 30, 2009	Nine months ended September 30, 2008
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 1,758	$ 2,606
Financing activities	261	(316)
Investing activities	(1,818)	(2,465)
Increase (decrease) in cash and cash equivalents	$ 201	$ (175)

Operating activities

Our *net cash provided by operating activities* for the nine months ended September 30, 2009, decreased from the same period in 2008 due primarily to the decrease in our operating results.

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Management s Discussion and Analysis (Continued)

Significant transactions in 2008 include:

$144 million paid by Transco related to a general rate case with the FERC.

$128 million of cash received related to a favorable ruling from the Alaska Supreme Court.

Financing activities

Significant transactions include:

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

$474 million of cash payments in 2008 for the repurchase of our common stock.

$362 million of cash received in 2008 primarily from the completion of the Williams Pipeline Partners L.P. initial public offering.

$75 million net proceeds in 2008 from Gas Pipeline s debt transactions.

Investing activities

Significant transactions include:

Capital expenditures totaled $1,829 million and $2,591 million for 2009 and 2008, respectively, and were largely related to Exploration & Production. Included is a $255 million payment in September 2009 by Exploration & Production for the purchase of additional properties in the Piceance basin (see Results of Operations Segments, Exploration & Production.)

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

$148 million of cash received in 2008 from Exploration & Production s sale of a contractual right to a production payment.

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

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 interest rate risk exposure is primarily associated with our debt portfolio and has not materially changed during the first nine months of 2009. 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, as well as other market factors, such as market volatility and 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 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 portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Derivative 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 $13 million at September 30, 2009. Our value at risk for contracts held for trading purposes was less than $1 million at September 30, 2009 and December 31, 2008.

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
Exploration & Production	Natural gas sales
Midstream	Natural gas purchases NGL sales
Gas Marketing Services	Natural gas purchases and sales

The fair value of our nontrading derivatives was a net asset of $126 million at September 30, 2009.

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The value at risk for all derivative contracts held for nontrading purposes was $37 million at September 30, 2009, and $33 million at December 31, 2008.

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 $222 million as of September 30, 2009. 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 the Internal Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

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

Third-Quarter 2009 Changes in Internal Controls

There have been no changes during the third quarter of 2009 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, 2008, 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:

We are subject to risks associated with climate change.

There is a growing belief that emissions of greenhouse gases may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of greenhouse gases have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks.

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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.

Compliance with environmental laws requires significant expenditures, including clean up costs and damages arising out of contaminated properties. In addition, the possible failure to comply with environmental laws and regulations might result in the imposition of fines and penalties. 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 climate change create financial risk. The United States Congress and certain states have for some time been considering various forms of legislation related to greenhouse gas emissions. There have also been international efforts seeking legally binding reductions in emissions of greenhouse gases. In addition, increased public awareness and concern may result in more state, federal, and international proposals to reduce or mitigate the emission of greenhouse gases.

Several bills have been introduced in the United States Congress that would compel carbon dioxide emission reductions. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act which is intended to decrease annual greenhouse gas emissions through a variety of measures, including a cap and trade system which limits the amount of greenhouse gases 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 greenhouse gases. While it is not clear whether any federal climate change law will be passed this year, 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 greenhouse gas 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 greenhouse gases as a financial risk, this could negatively impact our cost of and access to capital.

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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Risks Related to Weather, other Natural Phenomena and Business Disruption

Our assets and operations can be adversely affected by weather and other natural phenomena.

Our assets and operations, including those located offshore, can be adversely affected by hurricanes, floods, earthquakes, tornadoes and other natural phenomena and weather conditions, including extreme temperatures, making it more difficult for us to realize the historic rates of return associated with these assets and operations. Insurance may be inadequate, and in some instances, we may be unable to obtain insurance on commercially reasonable terms, if at all. A significant disruption in operations or a significant liability for which we were not fully insured could have a material adverse effect on our business, results of operations and financial condition.

Our customers energy needs vary with weather conditions. To the extent weather conditions are affected by climate change or demand is impacted by regulations associated with climate change, customers energy use could increase or decrease depending on the duration and magnitude of the changes, leading to either increased investment or decreased revenues.

Item 6. Exhibits

Exhibit 3.1	Restated Certificate of Incorporation of The Williams Companies, Inc. (filed on August 6, 2009, as Exhibit 3.1 to The Williams Companies, Inc. s Form 10-Q) and incorporated herein by reference.
Exhibit 3.2	Restated By-Laws (filed on September 24, 2008 as Exhibit 3.1 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
Exhibit 12	Computation of Ratio of Earnings to Fixed Charges.(1)
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.(1)
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.(1)
Exhibit 32	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.(2)
Exhibit 101.INS	XBRL Instance Document.(2)
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.(2)
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.(2)
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.(2)
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.(2)
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.(2)

(1) Filed herewith

(2)

Furnished herewith

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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)

October 29, 2009