WILLIAMS COMPANIES INC
Form 10-Q
April 30, 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 March 31, 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 of Incorporation)	(IRS Employer Identification Number)
ONE WILLIAMS CENTER, TULSA, OKLAHOMA	74172
(Address of principal executive office)	(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). o 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 April 27, 2009
Common Stock, $1 par value	580,096,386 Shares

The Williams Companies, Inc.
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Certain matters contained in this report include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements discuss our expected future results based on current and pending business operations. 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, might, planned, potential, projects, expressions. These forward-looking statements 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 (NGL) 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 which could cause actual results to differ from those in the forward-looking statements include:

- 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;
- 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;
- Our exposure to the credit risk of our customers;
- 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 Form 10-Q.

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

(Dollars in millions, except per-share amounts)	**Three months ended March 31, 2009**	**2008**
Revenues:		
Exploration & Production	$ 553	$ 728
Gas Pipeline	401	413
Midstream Gas & Liquids	899	1,557
Gas Marketing Services	867	1,650
Other	7	6
Intercompany eliminations	(599)	(1,150)
Total revenues	2,128	3,204
Segment costs and expenses:		
Costs and operating expenses	1,668	2,353
Selling, general and administrative expenses	123	112
Provision for doubtful accounts and notes	50	(1)
Other (income) expense net	270	(117)
Total segment costs and expenses	2,111	2,347
General corporate expenses	40	42
Operating income (loss):		
Exploration & Production	74	427
Gas Pipeline	164	170
Midstream Gas & Liquids	(220)	238
Gas Marketing Services	(2)	21
Other	1	1
General corporate expenses	(40)	(42)
Total operating income (loss)	(23)	815
Interest accrued	(166)	(165)
Interest capitalized	20	8
Investing income (loss)	(61)	55
Other income (expense) net	(2)	5
Income (loss) from continuing operations before income taxes	(232)	718
Provision (benefit) for income taxes	(15)	263

Income (loss) from continuing operations	(217)	455
Income (loss) from discontinued operations	(7)	84
Net income (loss)	(224)	539
Less: Net income (loss) attributable to noncontrolling interests	(52)	39
Net income (loss) attributable to The Williams Companies, Inc.	$ (172)	$ 500
Amounts attributable to The Williams Companies, Inc.:		
Income (loss) from continuing operations	$ (165)	$ 416
Income (loss) from discontinued operations	(7)	84
Net income (loss)	$ (172)	$ 500
Basic earnings (loss) per common share:		
Income (loss) from continuing operations	$ (.29)	$ .71
Income (loss) from discontinued operations	(.01)	.14
Net income (loss)	$ (.30)	$ .85
Weighted-average shares (thousands)	579,495	585,518
Diluted earnings (loss) per common share:		
Income (loss) from continuing operations	$ (.29)	$ .70
Income (loss) from discontinued operations	(.01)	.14
Net income (loss)	$ (.30)	$ .84
Weighted-average shares (thousands)	579,495	598,627
Cash dividends declared per common share	$ .11	$ .10

See accompanying notes.

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

(Dollars in millions, except per-share amounts)	March 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,786	$ 1,439
Accounts and notes receivable (net of allowance of $90 at March 31, 2009 and $40 at December 31, 2008)	683	941
Inventories	242	260
Derivative assets	1,077	1,464
Other current assets and deferred charges	271	307
Total current assets	4,059	4,411
Investments	902	971
Property, plant and equipment, at cost	25,926	25,936
Less accumulated depreciation, depletion and amortization	(7,932)	(7,871)
Property, plant and equipment net	17,994	18,065
Derivative assets	877	986
Goodwill	1,011	1,011
Other assets and deferred charges	525	562
Total assets	$ 25,368	$ 26,006
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 828	$ 1,059
Accrued liabilities	1,058	1,171
Derivative liabilities	567	1,093
Long-term debt due within one year	164	196
Total current liabilities	2,617	3,519
Long-term debt	8,278	7,683
Deferred income taxes	3,374	3,390
Derivative liabilities	746	875
Other liabilities and deferred income	1,497	1,485
Contingent liabilities and commitments (Note 14)		
Equity:		
Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 615 million issued at March 31, 2009 and 613 million shares issued at December 31, 2008)	615	613

Capital in excess of par value	8,076	8,074
Retained earnings	639	874
Accumulated other comprehensive income (loss)	37	(80)
Less treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders equity	8,326	8,440
Noncontrolling interests in consolidated subsidiaries	530	614
Total equity	8,856	9,054
Total liabilities and equity	$ 25,368	$ 26,006

See accompanying notes.

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

	Three months ended March 31,					
	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:						
Net income (loss)	(172)	(52)	(224)	500	39	539
Other comprehensive income (loss), net of tax:						
Net unrealized gain (loss) on cash flow hedges, net of reclassification adjustments	123		123	(122)	2	(120)
Foreign currency translation adjustments	(13)		(13)	(21)		(21)
Pension benefits amortization of net actuarial loss	7		7	2		2
Total other comprehensive income (loss)	117		117	(141)	2	(139)
Total comprehensive income (loss)	(55)	(52)	(107)	359	41	400
Cash dividends common stock	(64)		(64)	(59)		(59)
Dividends and distributions to noncontrolling interests		(33)	(33)		(24)	(24)
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				(126)		(126)
Stock-based compensation, net of tax	5		5	19		19
Other		1	1	8	(1)	7
Ending balance	$ 8,326	$ 530	$ 8,856	$ 7,801	$ 583	$ 8,384

See accompanying notes.

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

(Dollars in millions)	Three months ended March 31, 2009	2008
OPERATING ACTIVITIES:		
Net income (loss)	$ (224)	$ 539
Adjustments to reconcile to net cash provided by operations:		
Depreciation, depletion and amortization	367	302
Provision (benefit) for deferred income taxes	(38)	153
Provision for loss on investments, property and other assets	339	2
Gain on sale of contractual production rights		(118)
Provision for doubtful accounts and notes	50	(1)
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	245	(62)
Inventories	13	(80)
Margin deposits and customer margin deposits payable	(2)	38
Other current assets and deferred charges	(13)	8
Accounts payable	(60)	98
Accrued liabilities	(216)	(117)
Changes in current and noncurrent derivative assets and liabilities	37	(19)
Other, including changes in noncurrent assets and liabilities	14	50
Net cash provided by operating activities	512	793
FINANCING ACTIVITIES:		
Proceeds from long-term debt	595	100
Payments of long-term debt	(31)	(115)
Proceeds from sale of limited partner units of consolidated partnerships		362
Dividends paid	(64)	(59)
Purchase of treasury stock		(93)
Dividends and distributions paid to noncontrolling interests	(33)	(24)
Changes in restricted cash	36	7
Changes in cash overdrafts	(41)	(31)
Other net	(6)	15
Net cash provided by financing activities	456	162
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(484)	(579)
Changes in accounts payable and accrued liabilities	(128)	43
Proceeds from sale of contractual production rights		118
Other net	(9)	4

Net cash used by investing activities	(621)	(414)
Increase in cash and cash equivalents	347	541
Cash and cash equivalents at beginning of period	1,439	1,699
Cash and cash equivalents at end of period	$ 1,786	$ 2,240

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 our Annual Report on Form 10-K. 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 March 31, 2009, and results of operations and cash flows for the three months ended March 31, 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 consider a decrease in our total market capitalization below our consolidated stockholders equity to be an indicator of potential goodwill impairment. As of March 31, 2009, our total market capitalization was below our consolidated stockholders equity. We performed an interim evaluation as of March 31, 2009, and determined that no impairment of our goodwill was necessary. It is reasonably possible that we may be required to conduct an interim goodwill impairment evaluation again during 2009, which could result in a material impairment of goodwill.

Note 2. Basis of Presentation

Prior period amounts reported for Exploration & Production have been adjusted to reflect the presentation of certain revenues and costs on a net basis. These adjustments reduced *revenues* and reduced *costs and operating expenses* by the same amount, with no net impact on segment profit. The reductions for first quarter of 2008 were $20 million.

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

Noncontrolling Interests in Consolidated Subsidiaries

In January 2009, we adopted Statement of Financial Accounting Standards (SFAS) No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51. SFAS No. 160 establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries (previously referred to as minority interests) and is applied prospectively with the exception of the presentation and disclosure requirements which must be applied retrospectively for all periods presented. Noncontrolling ownership interests in consolidated subsidiaries are now presented in the consolidated balance sheet within equity as a component separate from stockholders equity. *Net income (loss)* now includes earnings (loss) attributable to both The Williams Companies, Inc., and the noncontrolling interests. Earnings per share continues to be based on earnings attributable to only The Williams Companies, Inc.

Master Limited Partnerships

We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the presumption of control of the general partner in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights, Williams Partners L.P. is consolidated within our Midstream Gas & Liquids

Notes (Continued)

(Midstream) segment. For 2009 distribution periods, we have agreed to waive our general partner incentive distribution rights, which we estimate would total $29 million based on current 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 hold approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, we consolidate Williams Pipeline Partners L.P. within our Gas Pipeline segment due to our control through the general partner.

Note 3. Venezuela Operations and Investments

Our Venezuela operations are primarily within our Midstream segment and are operated under long-term agreements for the exclusive benefit of the Venezuelan state-owned oil company, Petróleos de Venezuela S.A. (PDVSA). These operations include majority ownership in entities that own and operate gas compression facilities, as well as our equity investment in Accroven, which owns gas processing facilities and an NGL fractionation plant. Construction of these assets was funded through project financing that is collateralized by the stock, assets, and contract rights of the entities and is nonrecourse to us.

The collection of receivables from PDVSA has historically been slower and required more effort than other customers due to its policies and the political environment in Venezuela. As noted in our Annual Report on Form 10-K for the year ended December 31, 2008, PDVSA had failed to make regular payments to many service providers, including us. The past due payments from PDVSA triggered technical default of the related project debt in the fourth quarter of 2008, which resulted in classification of the entire debt balance as current. As of March 31, 2009, *long-term debt due within one year* includes $161 million of this debt, of which $38 million has a stated maturity within one year.

We previously expected PDVSA to resume regular payments following a February 15, 2009, referendum vote in Venezuela; however, that has not happened. PDVSA s continued nonperformance with us and others in the industry, their financial distress, and lack of communications with us has caused us to revise our assessment. We now believe it is probable that PDVSA will not cure the defaults. Without substantial payments from PDVSA, these operations will be forced to shut down. As required under our agreements, we have provided PDVSA with default notices for our majority-owned operations and expect Accroven to send similar notice in May 2009. In the event that PDVSA does not cure the defaults and does not comply with its contractual obligations to purchase the related assets, we will pursue all rights available to us under our agreements, including international arbitration.

As previously noted, the debt supporting these operations is fully secured by the assets, contract rights, and the stock of the project entities. The default under the loan agreements allows the lenders to, among other things, terminate their commitment to lend, accelerate the payments due, protect their rights and remedies by appropriate proceedings, or seek to enforce the agreements. To date, the lenders have elected to either defer or not pursue their available rights.

As a result of these circumstances and developments and our assessment of the low likelihood of PDVSA curing the defaults, we have fully reserved accounts receivable from PDVSA. In addition, we have ceased revenue recognition of these operations for the first quarter of 2009 as we no longer believe that the collectibility of revenues is reasonably assured. This indicator of impairment caused us to review our Venezuelan property, plant and equipment for recoverability and record an impairment charge based on the excess of the carrying value of the assets over their estimated fair value. We estimated fair value 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 impairment charge. We applied similar estimates and assumptions in evaluating our investment in Accroven and recognized an other-than-temporary loss in value. Certain deferred charges and credits have also been written off because the related future cash inflows and outflows are no longer expected to occur.

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Notes (Continued)

In addition, 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 for our remaining investment balance.

All of these charges, along with the corresponding tax impact, are summarized as follows:

Impact of Impairments and Related Charges on Consolidated Statement of Operations		**Three months ended March 31, 2009**	
		(Millions)	
Fully reserve accounts receivable	$	48	(a)
Impairment of property, plant and equipment		211	(b)
Write-off of deferred charges and credits		30	(b)
Other		6	(b)
		295	
Impairment of equity investment in Accroven		75	(c)
Impairment of Exploration & Production s cost-based investment		11	(d)
Income tax benefit from reversal of deferred tax balances		(76)	(e)
Net loss	$	305	
Net loss attributable to noncontrolling interests	$	64	
Net loss attributable to The Williams Companies, Inc.	$	241	

Classification within Consolidated Statement of Operations:

(a) Provision for doubtful accounts and notes

(b) Other (income) expense net within segment costs and expenses

(c) Loss from investments within Investing income (loss)

(d) Investing income (loss)

(e) Provision (benefit) for income taxes

Included within *Other* above is a $2 million loss related to an interest rate cap that was previously designated as a cash flow hedge. We concluded that related future interest payments were probable of not occurring and, thus, discontinued cash flow hedge accounting and reclassified this amount from accumulated other comprehensive income into earnings.

In addition to the above charges, Midstream s Venezuela operations incurred an additional first-quarter 2009 net loss of $10 million, of which $5 million is attributable to noncontrolling interests.

After these adjustments, our carrying value as of March 31, 2009, associated with these operations is primarily comprised of $67 million of restricted cash, $106 million of property, plant and equipment, and $161 million of secured debt.

Note 4. Discontinued Operations

Results of discontinued operations are summarized as follows:

	Three months ended March 31,	
	2009	2008
	(Millions)	
Revenues	$	$
Income (loss) from discontinued operations before income taxes	$ (7)	$ 132
Provision for income taxes		(48)
Income (loss) from discontinued operations	$ (7)	$ 84

In first-quarter 2008, we recognized pre-tax income of $128 million in *income (loss) from discontinued operations before income taxes* related to our former Alaska operations. This amount includes $74 million related to cash received upon the favorable resolution of a matter involving pipeline transportation rates and $54 million related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank.

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Note 5. Asset Sales, Impairments and Other Accruals

The following table presents significant gains or losses from asset sales, impairments and other accruals or adjustments reflected in *other (income) expense net* within *segment costs and expenses*.

	Three months ended March 31, 2009	Three months ended March 31, 2008
	(Millions)	
Exploration & Production		
Gain on sale of contractual right to an international production payment	$	$(118)
Penalties from early release of drilling rigs	34	
Impairments of certain gathering assets (see Note 12)	5	
Midstream		
Impairments and related charges associated with Venezuela operations (see Note 3)	247	

Note 6. Provision (Benefit) for Income Taxes

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

	Three months ended March 31, 2009	Three months ended March 31, 2008
	(Millions)	
Current:		
Federal	$ 12	$ 108
State	2	17
Foreign	9	14
	23	139
Deferred:		
Federal	34	102
State	4	16
Foreign	(76)	6
	(38)	124
Total provision (benefit)	$ (15)	$ 263

The effective income tax rate on the total benefit for the three months ended March 31, 2009 is less than the federal statutory rate due primarily to the valuation allowance on foreign taxes related to the Venezuelan impairments and write-offs partially offset by the impact of nontaxable noncontrolling interests. (See Note 3.)

The effective income tax rate on the total provision for the three months ended March 31, 2008 is greater than the federal statutory rate due primarily to the effect of state income taxes partially offset by the impact of nontaxable noncontrolling interests.

During the next twelve months, we do not expect ultimate resolution of any unrecognized tax benefit associated with a domestic or international matter will have a material impact on our financial position. However, certain matters we have contested to the Internal Revenue Service Appeals Division could be resolved and result in a reduction to our unrecognized tax benefit.

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Notes (Continued)

Note 7. Earnings (Loss) Per Common Share from Continuing Operations

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

	Three months ended March 31, 2009	2008
	(Dollars in millions, except per share amounts; shares in thousands)	
Income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders for basic and diluted earnings (loss) per common share (1)	$ (165)	$ 416
Basic weighted-average shares (2)	579,495	585,518
Effect of dilutive securities:		
Nonvested restricted stock units		1,465
Stock options		4,325
Convertible debentures		7,319
Diluted weighted-average shares	579,495	598,627
Earnings (loss) per common share from continuing operations:		
Basic	$ (.29)	$ .71
Diluted	$ (.29)	$ .70

(1) The three months ended March 31, 2008 includes $1 million of interest expense, net of tax, associated with our convertible debentures. This amount has been added back to *income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders* to calculate diluted earnings per common share.

(2) The decrease in the basic weighted-average shares is due primarily to our stock repurchases, partially offset by stock issuances related to conversions of our convertible debentures, stock-based compensation, and employee purchases of company stock under the Employee Stock Purchase Plan during the period from April 1, 2008 to March 31, 2009.

For the three months ended March 31, 2009, 1.4 million weighted-average nonvested restricted stock units and 1.5 million weighted-average stock options have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive due to the loss from continuing operations attributable to The Williams Companies, Inc.

Additionally, for the three months ended March 31, 2009, 4.8 million weighted-average shares related to the assumed conversion of our convertible debentures, as well as the related interest, net of tax, have been excluded from the computation of diluted earnings per common share. Inclusion of these shares would have an antidilutive effect on the diluted earnings per common share. We estimate that if *income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders* was $54 million of income for the three months ended March 31, 2009, then these shares would become dilutive.

The table below includes information related to stock options that were outstanding at March 31 of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the first quarter weighted-average market price of our common shares.

	March 31, 2009	**March 31, 2008**
Options excluded (millions)	6.7	2.2
Weighted-average exercise prices of options excluded	$25.62	$37.10
Exercise price ranges of options excluded	$ 15.71 - $42.29	$ 34.54 - $42.29
First quarter weighted-average market price	$13.05	$33.97

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Notes (Continued)

Note 8. Employee Benefit Plans

Net periodic benefit expense is as follows:

	Pension Benefits Three months ended March 31,		Other Postretirement Benefits Three months ended March 31,	
	2009	2008	2009	2008
	(Millions)			
Components of net periodic benefit expense:				
Service cost	$ 7	$ 5	$	$ 1
Interest cost	15	14	4	4
Expected return on plan assets	(14)	(20)	(2)	(3)
Amortization of prior service credit			(2)	
Amortization of net actuarial loss	11	2	1	
Amortization of regulatory asset			1	1
Net periodic benefit expense	$ 19	$ 1	$ 2	$ 3

During the three months ended March 31, 2009, we contributed $16 million to our pension plans and $4 million to our other postretirement benefit plans. During April 2009, we contributed an additional $45 million to our pension plans for a total of $61 million. 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 $12 million to our other postretirement benefit plans in 2009 for a total of approximately $16 million.

Note 9. Inventories

Inventories are as follows:

	March 31, 2009	December 31, 2008
	(Millions)	
Natural gas liquids	$ 45	$ 56
Natural gas in underground storage	82	97
Materials, supplies and other	115	107
	$ 242	$ 260

Note 10. Debt and Banking Arrangements

Revolving Credit and Letter of Credit Facilities (Credit Facilities)

At March 31, 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 March 31, 2009 (Millions)
$400 million unsecured credit facility	April 2009	$
$100 million unsecured credit facility	May 2009	

$700 million unsecured credit facilities	September 2010		236
$1.5 billion unsecured credit facility	May 2012		75
$200 million Williams Partners L.P. unsecured credit facility	December 2012		
		$	311

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.

Notes (Continued)

Issuances and Retirements

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 connection with this issuance, we are obligated to file a registration statement offering to exchange the notes for a new issue of substantially identical notes (except they will not be subject to transfer restrictions) to be registered under the Securities Act of 1933, as amended, within 180 days after the March 5, 2009 closing. We are obligated to use commercially reasonable efforts to cause such registration statements to be declared effective within 270 days after closing. We may also be required to provide a shelf registration statement to cover resales of the notes under certain circumstances. If we fail to fulfill these obligations, we may be required to pay additional interest on the affected securities. The rate of additional interest will be 0.25 percent per annum on the principal amount of the affected securities for the first 90-day period immediately following the default, increasing over time up to a maximum amount of 0.5 percent annually.

Note 11. 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. For the three months ended March 31, 2009, we have not incurred any significant losses due to counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of March 31, 2009, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 37	$ 38
Energy marketers and traders	81	658
Financial institutions	1,268	1,269
	$ 1,386	1,965
Credit reserves		(11)
Gross credit exposure from derivatives		$ 1,954

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 March 31, 2009, excluding collateral support discussed below, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$	$ 1
Energy marketers and traders	70	75

Financial institutions	767	767
	$ 837	843
Credit reserves		(11)
Net credit exposure from derivatives		$ 832

(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.

Notes (Continued)

Our nine largest net counterparty positions represent approximately 99 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are six counterparty positions, representing 81 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 March 31, 2009, the designated collateral agent held $378 million of collateral support on our behalf under Exploration & Production s hedging facility. In addition, we held collateral support, including letters of credit, of $36 million related to our other derivative positions.

Note 12. 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 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 in active markets or liabilities 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, including certain instruments that were part of sales transactions in 2007 and remain to be assigned to the purchaser. These unassigned instruments are entirely offset by reciprocal positions entered into directly with the purchaser. These reciprocal positions have also been included in Level 1.

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 and swaps.

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. Instruments in this category primarily include OTC options.

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.

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Notes (Continued)

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:

	March 31, 2009				December 31, 2008			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Assets:								
Energy derivatives	$ 322	$ 945	$ 687	$ 1,954	$ 680	$ 1,223	$ 547	$ 2,450
Other assets	11		7	18	13		7	20
Total assets	$ 333	$ 945	$ 694	$ 1,972	$ 693	$ 1,223	$ 554	$ 2,470
Liabilities:								
Energy derivatives	$ 296	$ 969	$ 48	$ 1,313	$ 615	$ 1,313	$ 40	$ 1,968
Total liabilities	$ 296	$ 969	$ 48	$ 1,313	$ 615	$ 1,313	$ 40	$ 1,968

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures 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 also incorporates the time value of money and credit risk factors including the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash deposits and letters of credit) and our nonperformance risk on our liabilities.

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 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 by management.

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 fair value of options is estimated using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas other model inputs, such as implied volatility by location, are unobservable and require judgment in estimating. The instruments included in Level 3 at March 31, 2009, predominantly consist of options that primarily hedge future sales of production from our

Exploration & Production segment, are structured as costless collars, which combine an option to purchase and an option to sell in order to set a minimum and maximum transaction price, and are financially settled.

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Notes (Continued)

The following table presents 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 March 31,			
	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 (loss) from continuing operations*	137		6	
Included in *other comprehensive income (loss)*	133		(179)	
Purchases, issuances, and settlements	(138)		2	
Transfers into Level 3			(1)	
Transfers out of Level 3				
Ending balance	$ 639	$ 7	$ (186)	$ 10
Unrealized gains (losses) included in *income (loss) from continuing operations* relating to instruments still held at March 31	$	$	$ 1	$

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

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

Fair Value Measurements Using:

	March 31, 2009				
	Level 1	Level 2	Level 3	Total	Total Losses for three months ended March 31, 2008
			(Millions)		
Impairments:					
Midstream Venezuelan property (see Note 3)	$	$	$ 106	$ 106	$ (211)
Midstream investment in Accroven (see Note 3)					(75)
Exploration & Production gathering assets			11	11	(5)

Exploration & Production cost-based investment (see Note 3)					(11)
	$	$	$ 117	$ 117	$ (302)

Exploration & Production recorded an impairment charge of $5 million related to certain gathering assets. This impairment analysis was based on a comparison of the estimated fair value to the carrying value, including an assessment of undiscounted and discounted future cash flows.

Note 13. 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 under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, while other derivatives have not been designated as 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

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Notes (Continued)

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 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. Midstream does not have any commodity-related cash flow hedges at March 31, 2009.

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 SFAS No. 133 hedges, 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, basis, index, and options. The fixed price category includes physical and financial derivative transactions that settle at a fixed location price. The basis category includes financial derivative transactions priced off the difference in value between a commodity at two specific delivery points. The index category includes physical derivative transactions at an unknown future price. The options category includes all fixed price options or combination of options (collars) that set a floor and/or ceiling for the transaction price of a commodity.

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Notes (Continued)

The following table depicts the notional amounts in millions of British Thermal Units of the net long (short) positions in our commodity derivatives portfolio as of March 31, 2009. 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 (MMBtu)		Fixed Price	Basis	Index	Options
Designated					
Exploration & Production	Risk Management	(54,700,000)	(49,850,000)		(264,325,000)
Gas Marketing Services	Risk Management	*	*		
Not Designated					
Exploration & Production	Risk Management			(41,298,800)	
Gas Marketing Services	Risk Management	(7,767,499)	(7,900,000)	600,000	
Midstream	Risk Management			93,045,413	
Gas Marketing Services	Other	(351,286)	591,000		

* Volumes related to offsetting positions net to zero.

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 and 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.

	March 31, 2009	
	Assets	Liabilities
	(Millions)	
Designated as hedging instruments	$ 902	$ 129
Not designated as hedging instruments:		
Legacy natural gas contracts from former power business	725	756
All other	327	428
Total derivatives not designated as hedging instruments	1,052	1,184
Total derivatives	$ 1,954	$ 1,313

The following table presents gains and losses for our energy commodity derivatives designated as cash flow hedges.

	Three months ended March 31, 2009 (Millions)	Classification
Net gain recognized in other comprehensive income (effective portion)	$ 325	
Net loss reclassified from accumulated other comprehensive income into income (effective portion)	$ (129)	Revenues
Gain recognized in income (ineffective portion)	$ 1	Revenues

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

Net gains from energy commodity derivatives not designated as hedging instruments were $11 million for the quarter ended March 31, 2009, and included $15 million in revenues partially offset by $4 million in costs and operating expenses.

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

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Notes (Continued)

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.

As of March 31, 2009, we have collateral posted to derivative counterparties totaling $110 million, all of which is in the form of letters of credit, to support the aggregate fair value of our net derivative liability position of $191 million, which includes a reduction of $15 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 were triggered, was $96 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 are 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 March 31, 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 March 31, 2009, $311 million of net gains (net of income tax provision of $189 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of March 31, 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.

Note 14. 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.

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Notes (Continued)

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

Refund proceedings

Although we entered into the State Settlement and Utilities Settlement, which resolved 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 March 31, 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. Because of our settlements, we do not expect that the final resolution of refund obligations will have a material impact on us. 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.

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 in principle that will resolve all California litigation.

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.

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.

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 Transcontinental Gas Pipe Line Company, LLC (Transco) subsidiary has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At March 31, 2009, we had accrued liabilities of $5 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

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Notes (Continued)

$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 remediation activities at certain sites to comply with Washington s current environmental standards. At March 31, 2009, we have accrued liabilities of $9 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

In March 2008, the EPA issued a new air quality standard for ground level ozone. The new standard will likely impact the operations of our interstate gas pipelines and cause us to incur additional capital expenditures to comply. At this time we are unable to estimate the cost of these additions that may be required to meet the new 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 March 31, 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.

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.

<u>Agrico</u>

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 March 31, 2009, we have accrued liabilities of $9 million for such excess costs.

Notes (Continued)

Other

At March 31, 2009, we have accrued environmental liabilities of $13 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 have opposed class certification and a hearing on plaintiffs second motion to certify the class was held in April 2005. 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 and certain of our wholly owned subsidiaries. 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. The maximum amount of future payments that we could potentially be required to pay under these indemnifications depends upon the ultimate resolution of the claim and cannot currently be determined. Grynberg had also filed claims against approximately 300 other energy companies alleging that the defendants violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. 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 affirmed the District Court s dismissal. On April 14, 2009, Grynberg filed a petition for rehearing of the Tenth Circuit s judgment.

Notes (Continued)

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. WilTel was dismissed as a defendant as a result of its bankruptcy.

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 might request a writ of certiorari from the United States Supreme Court to appeal the Tenth Circuit s ruling. Any obligation of ours to the WilTel equity holders as a result of a settlement, or as a result of trial in the event of a successful appeal of the court s judgment, will not likely be covered by insurance. The extent of any such obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure could materially exceed amounts accrued for this matter.

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. We have accrued a total liability of $42 million related to this matter representing our exposure, including interest, through March 31, 2009. 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.

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

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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. We are not able to estimate the amount of any additional exposure at this time.

Certain other royalty matters are currently being litigated by other producers with a federal regulatory agency and with a state agency in New Mexico. Although we are not a party to these matters, the final outcome of those cases might lead to a future unfavorable impact on our results of operations.

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 March 31, 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 financial position.

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.

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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 approximately $41 million at March 31, 2009. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is approximately $37 million at March 31, 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 March 31, 2009.

Note 15. 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 (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.

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Notes (Continued)

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

	Exploration & Production	Gas Pipeline	Midstream	Gas Marketing Services (Millions)	Other	Eliminations	Total
Three months ended March 31, 2009							
Segment revenues:							
External	$ 101	$ 393	$ 885	$ 745	$ 4	$	$ 2,128
Internal	452	8	14	122	3	(599)	
Total revenues	$ 553	$ 401	$ 899	$ 867	$ 7	$ (599)	$ 2,128
Segment profit (loss)	$ 78	$ 179	$ (291)	$ (2)	$ 1	$	$ (35)
Less:							
Equity earnings	4	15	4				23
Loss from investments			(75)				(75)
Segment operating income (loss)	$ 74	$ 164	$ (220)	$ (2)	$ 1	$	17
General corporate expenses							(40)
Total operating loss							$ (23)
Three months ended March 31, 2008							
Segment revenues:							
External	$ (66)	$ 402	$ 1,544	$ 1,320	$ 4	$	$ 3,204
Internal	794	11	13	330	2	(1,150)	
Total revenues	$ 728	$ 413	$ 1,557	$ 1,650	$ 6	$ (1,150)	$ 3,204
Segment profit	$ 430	$ 180	$ 261	$ 21	$ 1	$	$ 893
Less equity earnings	3	10	23				36
Segment operating income	$ 427	$ 170	$ 238	$ 21	$ 1	$	857
General corporate expenses							(42)
Total operating income							$ 815

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

	Total Assets	
	March 31, 2009	December 31, 2008

	(Millions)	
Exploration & Production	$ 10,026	$ 10,286
Gas Pipeline	9,205	9,149
Midstream	6,655	7,024
Gas Marketing Services (1)	1,783	3,064
Other	3,474	3,532
Eliminations	(5,786)	(7,055)
	25,357	26,000
Assets of discontinued operations	11	6
Total	$ 25,368	$ 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.

Note 16. Recent Accounting Standards

In December 2008, the Financial Accounting Standards Board (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

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Notes (Continued)

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 will assess the application of this FSP on our disclosures in our Consolidated Financial Statements.

In April 2009, the FASB issued FSP No. FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (FSP FAS 107-1 and APB 28-1) that would amend FASB Statement No. 107, Disclosures about Fair Value of Financial Instruments (SFAS No. 107), to require disclosures about the fair value of financial instruments in interim financial statements as well as in annual financial statements. This FSP applies to all financial instruments and entities within the scope of SFAS No. 107. An entity is required to disclose the fair value of all financial instruments, whether recognized or not recognized in the statement of financial position, along with the related carrying amount. An entity is also required to disclose the method(s) and significant assumptions used to estimate the fair value of financial instruments. This FSP is effective for interim and annual reporting periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. This FSP does not require disclosures for earlier periods presented for comparative purposes at initial adoption. In periods after initial adoption, this FSP requires comparative disclosures only for periods ending subsequent to initial adoption. We are currently assessing the impact of the FSP on our disclosures in our Consolidated Financial Statements and will adopt the FSP in the second quarter of 2009.

In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2 Recognition and Presentation of Other-Than-Temporary Impairments (FSP FAS 115-2 and FAS 124-2) that would amend FASB Statements No. 115, Accounting for Certain Investments in Debt and Equity Securities and No. 124, Accounting for Certain Investments Held by Not-for-Profit Organizations . This FSP applies to other-than-temporary impairments of debt securities. This FSP is effective for interim and annual reporting periods ending after June 15, 2009, and is applied prospectively. We do not believe this FSP will have a material impact on our Consolidated Financial Statements.

In April 2009, the FASB issued FSP No. FAS 157-4 Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That are Not Orderly (FSP FAS 157-4). This FSP clarifies that in markets where there has been a significant decrease in the volume and level of activity that transactions in those markets may not be orderly and therefore significant adjustments to transactions or quoted prices from those markets may be necessary when measuring fair value. Reporting entities are required to disclose a change in valuation technique and the related inputs resulting from the application of this FSP and to quantify its effects. This FSP is effective for interim and annual periods ending after June 15, 2009, and is applied prospectively. We do not believe this FSP will have a material impact on our Consolidated Financial Statements.

Note 17. Subsequent Events

In April 2009, we announced the formation of a new midstream venture, Laurel Mountain Midstream LLC. In exchange for a 51 percent ownership interest in the new entity, we expect to contribute $102 million, subject to certain post-closing adjustments, and issue a $26 million note payable to the new entity. Our partner in the venture expects to contribute its Marcellus Shale gathering system located in southwest Pennsylvania. In addition to our ownership interest, we would operate the gathering system. We expect to account for this investment within our Midstream segment under the equity method due to the significant participatory rights of our partner such that we do not control the investment. The transaction is expected to close in second-quarter 2009.

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

Company Outlook

We expect the current overall economic recession and related lower energy commodity price environment as well as the challenging financial markets to continue throughout 2009. This is expected to result in sharply lower results of operations and cash flow from operations compared to 2008 levels and could also result in a further reduction in capital expenditures. The impacts could include the future nonperformance of counterparties or impairments of goodwill and long-lived assets. Considering this environment, 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. However, we believe we are well positioned to capture growth opportunities when commodity prices strengthen and as economic conditions improve. Although we expect a reduction in capital expenditures compared to the prior year, near-term investment in our businesses will remain significant and focused on completing major projects, meeting legal, regulatory, and/or contractual commitments, and maintaining a reduced level of natural gas production development.

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 14 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.

Income (loss) from continuing operations attributable to The Williams Companies, Inc., for the three months ended March 31, 2009, changed unfavorably by $581 million compared to the three months ended March 31, 2008. This decrease is reflective of:

A net after-tax loss of $246 million related to impairments and other charges associated with our Venezuela operations and investments (see Note 3 of Notes to Consolidated Financial Statements);

The overall unfavorable commodity price environment in the first quarter of 2009 as compared to 2008;

The absence of a $118 million pre-tax gain recorded in the first quarter of 2008 associated with the sale of our Peru interests.

See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for the three months ended March 31, 2009, decreased $281 million compared to the three months ended March 31, 2008, primarily due to the decrease in our operating results. See additional discussion in Management s Discussion and Analysis of Financial Condition.

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. (See Note 10 of Notes to Consolidated Financial Statements.)

In April 2009, we announced the formation of a new midstream venture in the Marcellus Shale located in southwest Pennsylvania. (See Note 17 of Notes to Consolidated Financial Statements.)

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 2008 Annual Report on Form 10-K.

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 March 31, 2009, 35 percent of the total assets and 4 percent of the 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.

The determination of fair value also incorporates the time value of money and credit risk factors including the credit standing of the counterparties involved, the existence of master netting arrangements, the impact of credit enhancements (such as cash deposits and letters of credit) and our nonperformance risk on our liabilities. Currently, our approach is to 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 through 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 March 31, 2009, the credit reserve is $11 million on our net derivative assets and $15 million on our net derivative liabilities. Considering these factors and that we do not

Management s Discussion and Analysis (Continued)
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 March 31, 2009, 80 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 March 31, 2009, predominantly consist of options that hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled. The options are valued using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas a significant input, implied volatility by location, is unobservable. The impact of volatility on changes in the overall fair value of the options structured as collars is mitigated by the offsetting nature of the put and call positions. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices. The hedges are accounted for as cash flow hedges where net unrealized gains and losses from changes in fair value are recorded, to the extent effective, in *other comprehensive income (loss)* and subsequently impact earnings when the underlying hedged production is sold.

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 three months ended March 31, 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 12 of Notes to Consolidated Financial Statements.)

Critical Accounting Estimates

Impairment of Goodwill

We have goodwill of approximately $1 billion at Exploration & Production related to its domestic operations (the reporting unit) primarily resulting from a 2001 acquisition. As disclosed in our 2008 Annual Report on Form 10-K, we perform interim assessments of goodwill if an indicator of impairment is present. One example of an impairment indicator is a decline in total market capitalization below our total stockholders equity. As of March 31, 2009, our total market capitalization is below our total stockholders equity balance. Because quoted market prices are not available for the reporting unit, management applied a range of reasonable judgments in estimating its fair value. We estimated the fair value of the reporting unit on a stand-alone basis and also considered our market capitalization in corroborating our estimate of the fair value of the reporting unit. As of March 31, 2009, the estimated fair value of the reporting unit exceeds its carrying value, including goodwill, indicating no impairment of Exploration & Production s goodwill.

We estimated the fair value of the reporting unit on a stand-alone basis primarily by valuing proved and unproved reserves. We used an income approach (discounted cash flows) for valuing reserves. The significant inputs into the valuation of proved reserves included reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves and appropriate discount rates. Unproved reserves were valued using similar assumptions adjusted further for the uncertainty associated with these reserves.

In estimating the inputs, management must make assumptions that require judgments and are subject to change in response to changing market conditions and other future events. Significant assumptions in valuing proved reserves included prior year-end reserve quantities updated for first-quarter 2009 production, natural gas prices, adjusted for locational differences, averaging approximately $5.77 per Mcfe, and a pre-tax discount rate of 15 percent. Our discount rate was developed considering the risk inherent in the cash flows of an exploration and production business, recognizing that market participants may use varying discount factors when evaluating the fair value of a comparable business portfolio.

Management s Discussion and Analysis (Continued)

We further reviewed the fair value of the reporting unit estimated on a stand-alone basis, by considering our market capitalization in a reconciliation of the fair values of all our businesses, including the reporting unit. In this reconciliation, we determined our market capitalization, including a control premium, and estimated the fair values of all our businesses considering certain financial performance metrics. The range of control premiums that we considered were consistent with historical market sales transactions and also considered the current market environment. Market capitalization was based on our traded stock price for a reasonably short period of time before and after March 31, 2009. This analysis allowed management to consider market expectations in corroborating the reasonableness of the estimated fair value of the reporting unit.

We cannot predict future market conditions and events that might adversely affect the estimated fair value of the Exploration & Production reporting unit and possibly the reported value of goodwill. The estimated fair value of the reporting unit is significantly affected by natural gas prices, reserve quantities and market expectations for required rates of return. Further declines in natural gas prices would lower our estimates of fair value. There are numerous uncertainties inherent in estimating quantities of reserves that could affect our reserve quantities. Low prices for natural gas, regulatory limitations, or the lack of available capital for projects could adversely affect the development and production of additional reserves. Given the significant challenges affecting our businesses and the energy industry in 2009, these factors could impact us and require us to assess goodwill for possible impairment again during 2009.

Impairments of Venezuela Operations and Investments

For the three months ended March 31, 2009, we have recognized significant impairment charges related to our Venezuela operations and investments. These impairment measurements required management to evaluate different factors and scenarios and make considerably subjective estimates and assumptions regarding matters that are susceptible to change. The use of alternate estimates and/or assumptions would have resulted in the recognition of different impairment charges. (See Note 3 of Notes to Consolidated Financial Statements.)

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2009, compared to the three months ended March 31, 2008. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended March 31,			
	2009	2008	$ Change*	% Change*
	(Millions)			
Revenues	$ 2,128	$ 3,204	-1,076	-34%
Costs and expenses:				
Costs and operating expenses	1,668	2,353	+685	+29%
Selling, general and administrative expenses	123	112	-11	-10%
Provision for doubtful accounts and notes	50	(1)	-51	NM
Other (income) expense net	270	(117)	-387	NM
General corporate expenses	40	42	+2	+5%
Total costs and expenses	2,151	2,389		
Operating income (loss)	(23)	815		
Interest accrued net	(146)	(157)	+11	+7%
Investing income (loss)	(61)	55	-116	NM
Other income (expense) net	(2)	5	-7	NM

Income (loss) from continuing operations before income taxes	(232)	718		
Provision (benefit) for income taxes	(15)	263	+278	NM
Income (loss) from continuing operations	(217)	455		
Income (loss) from discontinued operations	(7)	84	-91	NM
Net income (loss)	(224)	539		
Less: Net income (loss) attributable to noncontrolling interests	(52)	39		
Net income (loss) attributable to The Williams Companies, Inc.	$ (172)	$ 500		

* + = Favorable change to *net income*; = Unfavorable change to *net income*; NM = A percentage calculation is not meaningful due to change in signs or a percentage change greater than 200.

Three months ended March 31, 2009 vs. three months ended March 31, 2008

The decrease in *revenues* is due primarily to lower natural gas liquid (NGL) and olefin production revenues and lower NGL, olefin and crude marketing revenues at Midstream. Additionally, Exploration & Production revenues decreased due to lower net realized average prices, partially offset by increased production volumes sold.

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Management s Discussion and Analysis (Continued)

The decrease in *costs and operating expenses* is due primarily to decreased NGL, olefin and crude marketing purchases and decreased costs associated with our olefins production business at Midstream.

The increase in *provision for doubtful accounts and notes* is due primarily to the $48 million charge to fully reserve Midstream s receivables from Petróleos de Venezuela S.A. (See Note 3 of Notes to Consolidated Financial Statements.)

Other (income) expense net within *operating income* in 2009 includes $247 million of impairments and related charges associated with Midstream s Venezuela operations. (See Note 3 of Notes to Consolidated Financial Statements.) Also included are $34 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 $118 million on the sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production. Also included are $10 million of net gains on foreign currency exchanges, primarily at Midstream.

The unfavorable change in *operating income (loss)* reflects the $295 million of impairments and related charges associated with Midstream s Venezuela operations, an overall unfavorable energy commodity price environment in the first quarter of 2009 compared to the first quarter of 2008, the absence of $118 million gain on the sale 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.

The unfavorable change in *investing income (loss)* is due primarily to a $75 million impairment of Midstream s Accroven equity investment and an $11 million impairment of a cost-based investment at Exploration & Production. (See Note 3 of Notes to Consolidated Financial Statements.)

Provision (benefit) for income taxes changed favorably primarily due to the pre-tax loss associated with the three months ended March 31, 2009. See Note 6 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 4 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations*.

Net income (loss) attributable to noncontrolling interests decreased primarily due to the impairments and related charges associated with Midstream s Venezuela operations. (See Note 3 of Notes to Consolidated Financial Statements.)

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Management s Discussion and Analysis (Continued)

Results of Operations Segments

Exploration & Production

Overview of Three Months Ended March 31, 2009

Segment revenues and segment profit for the first three months of 2009 were significantly lower than the first three months of 2008 primarily due to the unfavorable effect of a significant decline in net realized average prices partially offset by higher production volumes. Additionally, the first three months of 2009 include expense of $34 million associated with contractual penalties from the early termination of drilling rig contracts. The first three months of 2008 include a $118 million gain on sale of our Peru interests. Highlights of the comparative periods include:

	For the three months ended March 31,		
	2009	**2008**	**% Change**
Average daily domestic production (MMcfe) (1)	1,225	1,013	+21%
Average daily total production (MMcfe)	1,278	1,062	+20%
Domestic net realized average price ($/Mcfe) (2)	$ 4.21	$ 6.58	-36%
Capital expenditures ($ millions)	$ 320	$ 391	-18%
Segment revenues ($ millions)	$ 553	$ 728	-24%
Segment profit ($ millions)	$ 78	$ 430	-82%

(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 due to continued development within the Piceance, Powder River, and Fort Worth basins.

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

The decrease in capital expenditures reflects our decision to reduce development activities in 2009 because of declining natural gas prices.

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 projected capital expenditures for 2009 are projected to be between $630 million and $730 million, which includes the reduction in drilling rigs deployed.

Slight growth in our annual average daily domestic production level compared to 2008, with fourth quarter 2009 volumes likely to be less than the prior comparable period.

Declines in cost of services and materials associated with development activities as demand for these resources decreases.

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 downturn in the global economy. A further decline in natural gas prices would impact these expectations for the remainder of the year.

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 will increase

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Management s Discussion and Analysis (Continued)

our costs of permitting and environmental compliance and 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.

Commodity Price Risk Strategy

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative forward sales contracts that fix the sales price relating to a portion of our future production using NYMEX and basis fixed-price contracts and collar agreements.

For the remainder of 2009, we have the following agreements and 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
Collar agreements Rockies	150	$ 6.11 - $9.04
Collar agreements San Juan	245	$ 6.58 - $9.62
Collar agreements Mid-Continent	95	$ 7.08 - $9.73
NYMEX and basis fixed-price	106	$ 3.71

The following is a summary of our agreements and contracts for daily production for the three months ended March 31, 2009 and 2008:

	Three months ended March 31,			
	2009		2008	
	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Collars Rockies	150	$ 6.11 - $9.04	200	$ 6.33 - $9.41
Collars San Juan	245	$ 6.58 - $9.62	147	$ 6.26 - $8.78
Collars Mid-Continent	95	$ 7.08 - $9.73	10	$ 7.12 - $8.67
NYMEX and basis fixed-price	107	$ 3.57	70	$ 3.92

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 March 31,	
	2009	2008
	(Millions)	
Segment revenues	$ 553	$ 728
Segment profit	$ 78	$ 430

Three months ended March 31, 2009 vs. three months ended March 31, 2008

Total *segment revenues* decreased $175 million, or 24 percent, primarily due to the following:

$138 million, or 22 percent, decrease in domestic production revenues reflecting $259 million associated with a 36 percent decrease in net realized average prices, partially offset by an increase of $121 million associated with a 20 percent increase in production volumes sold. Production revenues in 2009 and 2008 include approximately $9 million and $17 million, respectively, related to natural gas liquids and approximately $6 million and $14 million, respectively, related to condensate;

Management s Discussion and Analysis (Continued)

- $38 million decrease in revenues 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 expense.*

Total *segment costs and expenses* increased $178 million, primarily due to the following:

- The absence of a $118 million gain recorded in the first quarter of 2008 associated with the sale of our Peru interests;
- $53 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and the increased capitalized drilling costs;
- $34 million of expense related to penalties from the early release of rigs as previously discussed;
- $11 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins;
- $10 million higher exploratory expense in 2009, primarily related to 3-D seismic costs;
- $5 million of impairments of certain gathering assets in 2009.

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

- $38 million decrease in expenses 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 increase in *segment revenues*;
- $21 million lower operating taxes due to lower average market prices, partially offset by higher production volumes sold.

The $352 million decrease in s*egment profit* is primarily due to the 36 percent decrease in net realized average domestic prices, the absence of a $118 million gain associated with the sale of our Peru interests in 2008, $53 million higher depreciation, depletion and amortization expense and $34 million of expense related to rig release penalties, partially offset by the 20 percent increase in domestic production volumes sold.

Gas Pipeline

Overview of Three Months Ended March 31, 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 $192 million.

85 North Expansion Project

In the first quarter of 2009, we filed an application with 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 $248 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.

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Management s Discussion and Analysis (Continued)

Williams Pipeline Partners L.P.

We own approximately 47.7 percent of Williams Pipeline Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. We consolidate Williams Pipeline Partners L.P. within our Gas Pipeline segment due to our control through the general partner. (See Note 2 of Notes to Consolidated Financial Statements.) 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 up to $200 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 by November 2009.

Colorado Hub Connection project

In April 2009, we received approval from the FERC to construct 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 March 31,	
	2009	**2008**
	(Millions)	
Segment revenues	$ 401	$ 413
Segment profit	$ 179	$ 180

Three months ended March 31, 2009 vs. three months ended March 31, 2008

Segment revenues decreased $12 million, or 3 percent, due primarily to a $16 million decrease in revenues from transportation imbalance settlements (offset in *costs and operating expenses*) partially offset by an $8 million increase in other service revenues.

Costs and operating expenses decreased $6 million, or 3 percent, due primarily to a decrease in costs of $16 million associated with transportation imbalance settlements (offset in *segment revenues*) partially offset by a $6 million increase in depreciation expense.

Selling, general and administrative expenses (SG&A) increased $6 million, or 17 percent, due primarily to an increase in pension expense. We expect these higher costs to continue throughout 2009.

Other income (expense) net changed favorably by $6 million due primarily to lower project development costs.

Segment profit was comparable to the prior year due to the previously described changes and $5 million higher equity earnings primarily attributable to the completion of Gulfstream expansion projects.

Midstream Gas & Liquids

Overview of Three Months Ended March 31, 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.

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Management s Discussion and Analysis (Continued)

Significant events during 2009 include the following:

Venezuela Operations

As a result of circumstances and developments related to our Venezuela operations and investments, segment profit includes:

- Impairment charges of $211 million related to property, plant and equipment;
- Impairment charge of $75 million related to our equity investment in Accroven;
- Provision for doubtful accounts of $48 million to fully reserve our accounts receivable balance from PDVSA;
- $36 million of other related charges and write-offs.

In addition, we have ceased revenue recognition for these operations for the first quarter of 2009 as we no longer believe that the collectability of revenues is reasonably assured. See Note 3 of Notes to Consolidated Financial Statements for further discussion.

As a result of these circumstances, we expect the future results of our Venezuela operations may be reduced or eliminated. Our previous expectation was that these operations would generate $80 million in total segment profit for 2009.

Volatile commodity prices

Average NGL and natural gas prices, along with most other energy commodities, continued to be impacted in the first quarter of 2009 by the weakened economy. While prices experienced a further decline from average prices in the fourth quarter of 2008, they have stabilized compared to prices at the end of 2008. During the first quarter of 2008, strong per-unit NGL prices, driven by higher crude prices which impact NGL prices, in relationship to natural gas prices, contributed significantly to our realized NGL margins. NGL prices, especially ethane prices, were significantly lower in the first quarter of 2009 compared to the same period in 2008. Average natural gas prices decreased from first quarter 2008 to first quarter 2009, but relatively less than the decline in NGL prices. However, we continued to benefit from favorable gas price differentials in the Rocky Mountain area. These differentials contributed to realized per-unit margins that were generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and for liquids fractionated and sold at Mont Belvieu, Texas.

Our average realized NGL per-unit margin at our processing plants during the first quarter of 2009 was 20 cents per gallon (cpg), compared to 64 cpg in the first quarter of 2008. Strong NGL margins in 2007 and early 2008 significantly increased our rolling five-year average from 26 cpg at the end of 2007 to 37 cpg at the end of the first quarter of 2009.

Our average realized NGL per-unit margin has declined significantly from 59 cpg in the fourth quarter of 2008, which had benefited from:

- Financial hedging contracts in place during 2008;
- Recognizing NGL margins upon production at the plant, while the effect of the significant and rapid decline in NGL prices in the fourth quarter of 2008 impacted the NGL marketing business, which realized significant losses on NGL volumes in transit from processing plants to downstream markets;
- A favorable product mix reflecting a higher percentage of non-ethane to ethane volumes sold due to unfavorable ethane recovery economics.

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.

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Management s Discussion and Analysis (Continued)

Marcellus Shale Venture

In April 2009, we announced the formation of a new venture in the Marcellus Shale located in southwest Pennsylvania. Our partner in the venture expects to contribute 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. See Note 17 of Notes to Consolidated Financial Statements for further discussion.

Hurricane Ike

As a result of Hurricane Ike in September 2008, our Cameron Meadows NGL processing plant sustained significant damage. We plan to rebuild a portion of the Cameron Meadows NGL processing facility. Operations at our Cameron plant are suspended until we complete the reconstruction, which is expected in mid-2009. In the West region, we had to store NGL inventories due to the hurricane-related suspension of operations at a third-party fractionation facility at Mont Belvieu, Texas. A portion of this inventory was sold in the fourth quarter of 2008 and the remaining excess inventory was sold in the first quarter of 2009. While we expect business interruption insurance to largely mitigate any losses associated with outages beyond 60 days, the timing to resolve these claims is uncertain.

While our insurance premiums will increase modestly in 2009 compared to 2008, the overall level of coverage on our offshore assets in the Gulf Coast region against named windstorm events will significantly decrease as a result of significantly higher deductible amounts and significantly lower coverage limits.

Williams Partners L.P.

We own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. We consolidate Williams Partners L.P. within the Midstream segment due to our control through the general partner. (See Note 2 of Notes to Consolidated Financial Statements.) Midstream s segment profit includes 100 percent of Williams Partners L.P. s segment profit.

Management s Discussion and Analysis (Continued)

Outlook for the Remainder of 2009

The following factors could impact our business in 2009.

Commodity price changes

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. Forecasted domestic and global demand for polyethylene has weakened with the current instability in the global economy. A continued slow down in domestic and global economies could further reduce the demand for the petrochemical products we produce in both Canada and the United States. However, we continue to maintain a cost advantage in the broader petrochemical markets, as propylene and ethylene production processes which use NGL-based feedstocks are less expensive than other olefin production processes that use alternative crude-based feedstocks.

NGL, crude and natural gas prices are highly volatile. NGL price changes have historically tracked with changes in the price of crude oil; however, the recent relationship trend has been more volatile. With the decline in NGL prices, especially ethane, we expect lower per-unit NGL margins in 2009 compared to 2008. Additionally, we anticipate periods when it may not be economical to recover ethane in our Gulf Coast region, which will further reduce our segment profit. However, we expect continued favorable gas price differentials in the Rocky Mountain area to partially mitigate our per-unit margin declines and to minimize periods when it is not economical to recover ethane in the West region.

In our olefin production business, we expect both lower NGL-based feedstock costs and lower product prices and, as a result, we anticipate margins from our olefins production business for the total year 2009 to approximate 2008 levels.

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 is expected to reduce certain producer drilling activities. Although our customers in the West region are generally large producers and we anticipate they will continue with some level of drilling plans, we expect lower well-connects in 2009 as compared to 2008, which would impact our ability to grow gathering volumes over the long term.

We expect higher fee revenues, depreciation and operating expenses in our offshore Gulf Coast region as our Devils Tower infrastructure expansions serving the Blind Faith and Bass Lite prospects move into a full year of operation in 2009. We have not seen a reduction in offshore drilling and we expect to continue to connect new supplies in the deepwater. This increase is expected to be partially offset by lower volumes in other Gulf Coast areas due to natural declines.

Allocation of capital to expansion projects

We expect to spend $437 million in 2009 on our major expansion projects, of which approximately $344 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. We expect this project to begin contributing to our segment profit at the end of 2009.

The Willow Creek facility, in western Colorado, which we expect to begin processing Exploration & Production s natural gas production and contributing to our segment profit in the third quarter of 2009.

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 downturn. Although we actively manage our credit exposure through certain collateral or payment terms and arrangements, continued economic downturn may result in significant credit or bad debt losses.

We expect significant 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 March 31,	
	2009	**2008**
	(Millions)	
Segment revenues	$ 899	$ 1,557
Segment profit (loss):		
Domestic gathering & processing	$ 86	$ 204
Venezuela	(371)	26
NGL Marketing, Olefins, and Other	17	55
Indirect general and administrative expense	(23)	(24)
Total	$ (291)	$ 261

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 March 31, 2009 vs. three months ended March 31, 2008

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

A $233 million decrease in revenues associated with the production of NGLs primarily due to lower average NGL prices.

A $210 million decrease in NGL, olefin and crude marketing revenues primarily due to lower average NGL and crude prices, partially offset by higher crude volumes.

A $182 million decrease in revenues in our olefins production business primarily due to lower average product prices.

A $20 million decrease in fee-based revenues primarily due to $40 million lower revenues from our Venezuela operations primarily resulting from discontinuing revenue recognition as previously discussed, partially offset by $20 million in higher fee-based revenues in our domestic gathering and processing business.

Segment costs and expenses decreased $200 million, or 15 percent, primarily as a result of:

A $214 million decrease in NGL, olefin and crude marketing purchases primarily due to lower average NGL and crude prices, partially offset by higher crude volumes.

A $161 million decrease in costs in our olefins production business primarily due to lower feedstock costs.

A $95 million decrease in costs associated with the production of NGLs primarily due to lower average natural gas prices.

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Management s Discussion and Analysis (Continued)

A $17 million decrease in operating costs primarily due to lower system losses and gathering fuel, partially offset by higher depreciation, maintenance and repair expenses and pension expense.

These decreases are partially offset by $295 million of impairments and other charges related to our Venezuela operations, as previously discussed.

The decrease in Midstream s *segment profit* reflects the previously described changes in *segment revenues* and *segment costs and expenses,* the previously discussed $75 million loss from investment related to the impairment of our investment in Accroven, and lower equity earnings, primarily related to a $17 million decrease from Discovery Producer Services, LLC primarily due to lower processing margins and volumes.

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 $71 million decrease in the West region and a $47 million decrease in the Gulf Coast region.

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

A $93 million decrease in NGL margins due to a significant decrease in average NGL prices, partially offset by both a decrease in production costs reflecting lower natural gas prices and an increase in volumes sold. NGL equity volumes sold in the first quarter of 2008 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. While volumes were higher during the first quarter of 2009, NGL equity sales volumes were unfavorably impacted when certain gas processing agreements with producers converted from keep-whole to fee-based processing. Lower NGL transportation costs in the West region due to the transition from our previous shipping arrangement to transportation on the Overland Pass pipeline favorably impacted NGL margins in 2009.

A $23 million decrease in operating costs driven by unusually high system losses and gathering fuel expense in the first quarter of 2008 related to severe winter weather conditions.

A $12 million increase in fee revenues primarily due to 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* is primarily due to $45 million lower NGL margins reflecting lower volumes primarily due to periods during the first quarter of 2009 of reduced NGL recoveries due to unfavorable NGL economics and lower average NGL prices, partially offset by lower production costs reflecting lower natural gas prices. Also, depreciation was $7 million higher primarily due to expansion projects that came into service during the latter part of 2008, which is offset by $8 million higher fee revenues primarily due to connecting new supplies in the Bass Lite and Blind Faith prospects in the deepwater.

Venezuela

The decrease in *segment profit* for our Venezuela operations reflects the previously discussed total charges of $370 million related to impairments and other adjustments and to the previously discussed discontinuance of revenue recognition.

NGL marketing, olefins and other

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

$21 million in lower margins in our olefins production business primarily due to lower average prices for products produced in Canada.

Management s Discussion and Analysis (Continued)

$17 million in lower equity earnings in Discovery Producer Services, LLC as previously discussed.

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 fuel and shrink gas and hedging natural gas liquids sales for Midstream. Gas Marketing also provides similar services to third parties, such as producers. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage and related hedges, including certain legacy natural gas contracts and positions.

Overview of Three Months Ended March 31, 2009

Gas Marketing s operating results for the first three months of 2009 changed unfavorably compared to the first three months of 2008 primarily due to lower realized margins on our storage contracts and an inventory adjustment to the carrying value of the natural gas inventories in storage due to a decline in the price of natural gas. These were partially offset by favorable price movements on derivative positions executed to economically hedge the anticipated withdrawals of natural gas from storage and the absence of 2008 proprietary trading losses.

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 March 31,	
	2009	**2008**
	(Millions)	
Realized revenues	$ 855	$ 1,647
Net forward unrealized mark-to-market gains	12	3
Segment revenues	$ 867	$ 1,650
Segment profit (loss)	$ (2)	$ 21

Three months ended March 31, 2009 vs. three months ended March 31, 2008

Realized revenues represent (1) revenue from the sale of natural gas or completion of energy-related services and (2) gains and losses from the net financial settlement of derivative contracts. Realized revenues decreased $792 million due to a decrease in physical natural gas revenue as a result of a 52 percent decrease in average prices on physical natural gas sales which was slightly offset by a 7 percent increase in natural gas sales volumes. This decline is primarily related to gas sales associated with our transportation contracts and is offset by a similar decline in *segment costs and expenses* related to gas purchases associated with these same transportation contracts. The decline in *realized revenues* also includes a $42 million decrease associated with our storage contracts due to both declining prices and volumes.

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 favorable change of $9 million is primarily the result of favorable price movements on derivative contracts executed to economically hedge anticipated withdrawals of natural gas from storage, partially offset by the absence of an $11 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 $760 million primarily due to a 52 percent decrease in average prices on physical natural gas purchases which was slightly offset by a 10 percent increase in natural gas purchase volumes.

This decline is primarily related to the previously discussed gas purchases associated with our transportation contracts. Costs associated with our storage contracts were relatively comparable to the prior period.

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Management s Discussion and Analysis (Continued)

In addition, a $7 million unfavorable adjustment was made in 2009 to the carrying value of natural gas inventories in storage reflecting a decline in the price of natural gas.

The $23 million unfavorable change in *segment profit (loss)* is primarily due to a decline in realized margins on our storage contracts and an inventory adjustment due to declining prices, partially offset by mark-to-market gains on derivative positions executed to hedge the anticipated withdrawals of natural gas from storage and the absence of proprietary trading losses.

Other

Period-Over-Period Results

	Three months ended March 31,	
	2009	2008
	(Millions)	
Segment revenues	$ 7	$ 6
Segment profit	$ 1	$ 1

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

For the remainder of 2009, we expect operating results and cash flows to be sharply reduced from 2008 levels by the continued impact of lower energy commodity prices. This impact is 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 from 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.

In addition, we expect certain costs for services and materials to decline throughout the remainder of 2009 as demand for these resources declines.

Although the financial markets and energy commodity environment are expected to be depressed for at least 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 assumptions for the remainder of the year:

- 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 to be between $1.9 billion and $2.1 billion in 2009.

We estimate capital and investment expenditures will total $2.25 billion to $2.55 billion in 2009, with approximately $1.77 billion to $2.07 billion to be incurred over the remainder of the year. Of this total for 2009, approximately two-thirds 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 $250 million to $300 million for compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance.

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 year-end 2008 levels.
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 14 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. As noted below, certain of our unsecured revolving and letter of credit facilities are scheduled to expire in 2009 and 2010. These facilities were originated primarily in support of our former power business.

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

Management s Discussion and Analysis (Continued)

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 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	**March 31, 2009 (Millions)**
Cash and cash equivalents (1)		$ 1,786
Available capacity under our unsecured revolving and letter of credit facilities totaling $1.2 billion:		
$400 million facility	April 2009	400
$100 million facility	May 2009	100
$700 million facilities	September 2010	464
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility (2)	May 2012	1,355
Available capacity under Williams Partners L.P. s $200 million senior unsecured credit facility (3)	December 2012	188
		$ 4,293

(1) *Cash and cash equivalents* includes $22 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 $554 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) 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 10 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 March 31, 2009, we are significantly below the maximum allowed ratios.

(3) 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 10 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 March 31, 2009, they are in compliance with these covenants. However, since the ratios are calculated on a rolling four-quarter basis, the ratios at March 31, 2009, do not reflect the full-year impact of recent lower commodity prices.

Management s Discussion and Analysis (Continued)

Williams Partners L.P. has a shelf registration statement, which expires in October 2009, available for the issuance of $1.17 billion aggregate principal amount of debt and limited partnership unit securities.

At the parent-company level, we have a shelf registration statement, which as a well-known seasoned issuer, allows us to issue an unlimited amount of registered debt and equity securities. This shelf registration statement expires in May 2009. We expect to file a new shelf registration statement during the second quarter of 2009.

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 March 31, 2009, we estimate that a downgrade to a rating below investment grade would require us to post up to $375 million in additional collateral with third parties.

Sources (Uses) of Cash

	Three months ended March 31, 2009	Three months ended March 31, 2008
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 512	$ 793
Financing activities	456	162
Investing activities	(621)	(414)
Increase in cash and cash equivalents	$ 347	$ 541

Operating activities

Our *net cash provided by operating activities* for the three months ended March 31, 2009, decreased from the same period in 2008 due primarily to the decrease in our operating results. Included in the 2008 operating results is approximately $74 million of cash received in 2008 related to a favorable ruling from the Alaska Supreme Court in a matter involving pipeline transportation rates charged to our former Alaska refinery in prior periods.

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Management s Discussion and Analysis (Continued)

Financing activities

Our *net cash provided by financing activities* for the three months ended March 31, 2009, increased from the same period in 2008. Significant transactions include:

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 (see Note 10 of Notes to Consolidated Financial Statements).

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

Investing activities

Our *net cash used by investing activities* for the three months ended March 31, 2009, increased from the same period in 2008. Significant transactions include:

Capital expenditures totaled $484 million and $579 million for 2009 and 2008, respectively, and were largely related to Exploration & Production s drilling activity. *Net cash used by investing activities* in 2009 also includes $128 million primarily related to payments of previously accrued accounts payable and accrued liabilities associated with property, plant and equipment at Exploration & Production.

$118 million of cash received in 2008 from Exploration & Production s sale of a contractual right to a production payment.

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

We have various other guarantees and commitments which are disclosed in Note 14 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 three months of 2009. See Note 10 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 under SFAS No. 133 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 $23 million at March 31, 2009. Our value at risk for contracts held for trading purposes was $0.1 million at March 31, 2009 and $0.2 million at 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
Gas Marketing Services	Natural gas purchases and sales

The fair value of our nontrading derivatives was a net asset of $664 million at March 31, 2009.

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The value at risk for all derivative contracts held for nontrading purposes was $29 million at March 31, 2009, and $33 million at December 31, 2008. Derivative contracts included in our assets and liabilities of discontinued operations are included in the nontrading portfolio, but these had a value at risk amount of zero for both periods.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS No. 133. Of the total fair value of nontrading derivatives, SFAS No. 133 cash flow hedges had a net asset value of $773 million as of March 31, 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.

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.

First-Quarter 2009 Changes in Internal Controls Over Financial Reporting

There have been no changes during the first quarter of 2009 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 14 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.

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. Previously considered proposals have included, among other things, limitations on the amount of greenhouse gases that can be emitted (so-called caps) together with systems of emissions allowances. 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. Numerous states have also announced or adopted programs to stabilize and reduce greenhouse gases. If we are unable to recover or pass through all 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.

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

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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, as supplemented (filed on March 11, 2005 as Exhibit 3.1 to The Williams Companies, Inc. s Form 10-K) 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 4	Indenture dated as of March 5, 2009 between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on March 11, 2009 as Exhibit 4.1 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
Exhibit 10	Registration Rights Agreement dated as of March 5, 2009, between The Williams Companies, Inc. and Citigroup Global Markets Inc., on behalf of themselves and the Initial Purchasers listed on Schedule I thereto (filed on March 11, 2009 as Exhibit 10.1 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
Exhibit 12	Computation of Ratio of Earnings to Fixed Charges.*
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
Exhibit 32	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

* Filed 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)

April 30, 2009

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EXHIBIT INDEX

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