UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

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 *(State or Other Jurisdiction of Incorporation or Organization)*	**73-0569878** *(IRS Employer Identification No.)*
One Williams Center, Tulsa, Oklahoma *(Address of Principal Executive Offices)*	**74172** *(Zip Code)*

918-573-2000
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $1.00 par value	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
5.50% Junior Subordinated Convertible Debentures due 2033

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ☑

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 ☑ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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 ☑	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 Act). Yes o No ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant's most recently completed second quarter was approximately $18,963,794,420.

The number of shares outstanding of the registrant's common stock outstanding at February 21, 2008 was 585,021,071.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Annual Meeting of Stockholders to be held May 15, 2008 (Proxy Statement)	Part III

THE WILLIAMS COMPANIES, INC.
FORM 10-K

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DEFINITIONS

We use the following oil and gas measurements in this report:

Bcfe — means one billion cubic feet of gas equivalent determined using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

Bcf/d — means one billion cubic feet per day.

British Thermal Unit or BTU — means a unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

BBtud — means one billion BTUs per day.

Dekatherms or Dth or Dt — means a unit of energy equal to one million BTUs.

Mbbls/d — means one thousand barrels per day.

Mcfe — means one thousand cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

Mdt/d — means one thousand dekatherms per day.

MMcf — means one million cubic feet.

MMcf/d — means one million cubic feet per day.

MMcfe — means one million cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

MMdt — means one million dekatherms or approximately one trillion BTUs.

MMdt/d — means one million dekatherms per day.

PART I

Item 1. *Business*

In this report, Williams (which includes The Williams Companies, Inc. and, unless the context otherwise requires, all of our subsidiaries) is at times referred to in the first person as "we," "us" or "our." We also sometimes refer to Williams as the "Company."

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents electronically with the Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934, as amended (Exchange Act). You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC's Internet website at *http://www.sec.gov.*

Our Internet website is *http://www.williams.com.* We make available free of charge on or through our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Our Corporate Governance Guidelines, Code of Ethics, board committee charters and Code of Business Conduct are also available on our Internet website. We will also provide, free of charge, a copy of any of our corporate documents listed above upon written request to our Secretary at Williams, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172.

GENERAL

We are a natural gas company originally incorporated under the laws of the state of Nevada in 1949 and reincorporated under the laws of the state of Delaware in 1987. We were founded in 1908 when two Williams brothers began a construction company in Fort Smith, Arkansas. Today, we primarily find, produce, gather, process and transport natural gas. Our operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, and the Eastern Seaboard.

We continue to use Economic Value Added®(EVA®)[1] as the basis for disciplined decision making around the use of capital. EVA® is a tool that considers both financial earnings and a cost of capital in measuring performance. It is based on the idea that earning profits from an economic perspective requires that a company cover not only all of its operating expenses but also all of its capital costs. The two main components of EVA® are net operating profit after taxes and a charge for the opportunity cost of capital. We derive these amounts by making various adjustments to our reported results and financial position, and by applying a cost of capital. We look for opportunities to improve EVA® because we believe there is a strong correlation between EVA® improvement and creation of shareholder value.

Our goal is to create superior sustainable growth in EVA® and shareholder value. In early 2006, we set some ambitious three-year goals referred to as our game plan for growth. Our success in achieving the game plan for growth contributed to our significant accomplishments in 2007 designed to increase shareholder value, including:

- As a result of the sale of substantially all of our power assets to Bear Energy LP, a unit of The Bear Stearns Companies Inc. (NYSE: BSC) and strong business performance, our credit ratings were raised to investment grade.
- Continuing to increase our natural gas production through organic growth — natural gas production increased by 21 percent for the year.

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[1] Economic Value Added® (EVA®) is a registered trademark of Stern, Stewart & Co.

- Initiating a $1 billion stock repurchase program.
- Creating a new pipeline-focused master limited partnership, Williams Pipeline Partners L.P. (WMZ)
- Continuing growing our midstream-focused master limited partnership, Williams Partners L.P. (WPZ), with two significant drop-down transactions.
- Successfully executing rate cases on both of our major pipeline systems, driving increased earnings in Gas Pipeline.

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 918-573-2000.

2007 HIGHLIGHTS

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. The underwriters also exercised their option to purchase an additional 1.65 million common units at the same price.

In December 2007, Williams Partners L.P. (WPZ) acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million.

In December 2007, we repurchased $213 million of 7.125 percent notes due September 2011 and $22 million of 8.125 percent notes due March 2012.

On November 28, 2007, Transcontinental Gas Pipe Line Corporation (Transco) filed a formal stipulation and agreement with the Federal Energy Regulatory Commission (FERC) resolving all substantive issues in Transco's pending 2006 rate case. Final resolution of the rate case is subject to approval by the FERC.

On November 9, 2007, we closed on the sale of substantially all of our power business to Bear Energy, LP, a unit of The Bear Stearns Companies, Inc., for $496 million, subject to post-closing adjustments. The assets sold included tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software. This sale reduces the risk and complexity of our overall business.

In November 2007, our credit ratings were raised to investment grade based on improvements in our credit outlook. As we continue to invest and grow our natural gas businesses, our improved credit rating is expected to provide greater access to capital and more favorable loan terms. See additional discussion of credit ratings in *Management's Discussion and Analysis of Financial Condition*.

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open-market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. During 2007, we repurchased approximately 16 million shares for $526 million (including transaction costs) at an average cost of $33.08 per share.

In April 2007, our Board of Directors approved a regular quarterly dividend of 10 cents per share, which reflects an increase of 11 percent compared to the 9 cents per share that we paid in each of the four prior quarters and marks the fourth increase in our dividend since late 2004.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the rate case for Northwest Pipeline GP (Northwest Pipeline), formerly Northwest Pipeline Corporation.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 17 of our Notes to Consolidated Financial Statements for information with respect to each segment's revenues, profits or losses and total assets. See Note 9 for information with respect to property, plant and equipment for each segment.

BUSINESS SEGMENTS

Substantially all our operations are conducted through our subsidiaries. To achieve organizational and operating efficiencies, our activities are primarily operated through the following business segments:

- *Exploration & Production* — produces, develops and manages natural gas reserves primarily located in the Rocky Mountain and Mid-Continent regions of the United States and is comprised of several wholly owned and partially owned subsidiaries including Williams Production Company LLC and Williams Production RMT Company.
- *Gas Pipeline* — includes our interstate natural gas pipelines and pipeline joint venture investments organized under our wholly owned subsidiary, Williams Gas Pipeline Company, LLC. Gas Pipeline also includes WMZ, our master limited partnership formed in 2007.
- *Midstream Gas & Liquids* — includes our natural gas gathering, treating and processing business and is comprised of several wholly owned and partially owned subsidiaries including Williams Field Services Group LLC and Williams Natural Gas Liquids, Inc. Midstream also includes WPZ, our master limited partnership formed in 2005.
- *Gas Marketing Services*— manages our natural gas commodity risk through purchases, sales and other related transactions, under our wholly owned subsidiary Williams Gas Marketing, Inc.
- *Other* — primarily consists of corporate operations. Other also includes our interest in Longhorn Partners Pipeline, L.P. (Longhorn).

This report is organized to reflect this structure.

Detailed discussion of each of our business segments follows.

Exploration & Production

Our Exploration & Production segment, which is comprised of several wholly owned and partially owned subsidiaries, including Williams Production Company LLC and Williams Production RMT Company (RMT), produces, develops, and manages natural gas reserves primarily located in the Rocky Mountain (primarily New Mexico, Wyoming and Colorado) and Mid-Continent (Oklahoma and Texas) regions of the United States. We specialize in natural gas production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Arkoma, Green River and Fort Worth basins. Over 99 percent of Exploration & Production's domestic reserves are natural gas. Our Exploration & Production segment also has international oil and gas interests, which include a 69 percent equity interest in Apco Argentina Inc. (Apco Argentina), an oil and gas exploration and production company with operations in Argentina, and a four percent equity interest in Petrowayu S.A., a Venezuelan corporation that is the operator of a 100 percent interest in the La Concepcion block located in Western Venezuela.

Exploration & Production's primary strategy is to utilize its expertise in the development of tight-sands, shale, and coal bed methane reserves. Exploration & Production's current proved undeveloped and probable reserves provide us with strong capital investment opportunities for several years into the future. Exploration & Production's goal is to drill its existing proved undeveloped reserves, which comprise approximately 46 percent of proved reserves and to drill in areas of probable reserves. In addition, Exploration & Production provides a significant amount of equity production that is gathered and/or processed by our Midstream facilities in the San Juan basin.

Information for our Exploration & Production segment relates only to domestic activity unless otherwise noted. We use the terms "gross" to refer to all wells or acreage in which we have at least a partial working interest and "net" to refer to our ownership represented by that working interest.

Gas reserves and wells

The following table summarizes our U.S. natural gas reserves as of December 31 (using market prices on December 31 held constant) for the year indicated:

	2007	2006	2005
		(Bcfe)	
Proved developed natural gas reserves	2,252	1,945	1,643
Proved undeveloped natural gas reserves	1,891	1,756	1,739
Total proved natural gas reserves	4,143	3,701	3,382

No major discovery or other favorable or adverse event has caused a significant change in estimated gas reserves since year-end 2007. We have not filed on a recurring basis estimates of our total proved net oil and gas reserves with any U.S. regulatory authority or agency other than the Department of Energy (DOE) and the SEC. The estimates furnished to the DOE have been consistent with those furnished to the SEC, although Exploration & Production has not yet filed any information with respect to its estimated total reserves at December 31, 2007, with the DOE. Certain estimates filed with the DOE may not necessarily be directly comparable due to special DOE reporting requirements, such as the requirement to report gross operated reserves only. In 2006 and 2005 the underlying estimated reserves for the DOE did not differ by more than five percent from the underlying estimated reserves utilized in preparing the estimated reserves reported to the SEC.

Approximately 98 percent of our year-end 2007 United States proved reserves estimates were audited in each separate basin by Netherland, Sewell & Associates, Inc. (NSAI). When compared on a well-by-well basis, some of our estimates are greater and some are less than the estimates of NSAI. However, in the opinion of NSAI, the estimates of our proved reserves are in the aggregate reasonable by basin and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles. These principles are set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. NSAI is satisfied with our methods and procedures in preparing the December 31, 2007 reserve estimates and saw nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, as prepared by us. Reserve estimates related to properties underlying the Williams Coal Seam Gas Royalty Trust, which comprise approximately two percent of our total U.S. proved reserves, were prepared by Miller and Lents, LTD.

On December 12, 2007, the SEC issued a "Concept Release" to obtain information about the extent and nature of the public's interest in revising oil and gas reserves disclosure requirements which exist in their current form in Regulation S-K and Regulation S-X under the Securities Act of 1933 and the Securities Exchange Act of 1934. The Commission adopted the current oil and gas reserves disclosure requirement between 1978 and 1982. The Concept Release is intended to address significant changes in the oil and gas industry. Some commentators have expressed concern that the Commission's rules have not adapted to current practices and may not provide investors with the most useful picture of oil and gas reserves public companies hold. Comments were due to the Commission on February 19, 2008. At this time it is not possible to determine what effect changes the SEC may make, if any, will have on our reserve estimates and disclosures.

Oil and gas properties and reserves by basin

The table below summarizes 2007 activity and reserves for each of our areas, with further discussion following the table.

	Wells Drilled (Gross)	Wells Drilled (Operated)	Wells Producing (Gross)	Wells Producing (Net)	Wellhead Production (Net Bcfe)	Proved Reserves (Bcfe)	% of Total Proved Reserves
Piceance	574	544	2,467	2,295	197	2,847	69%
San Juan	146	47	3,109	821	55	576	14%
Powder River	637	457	4,831	2,200	62	413	10%
Mid-Continent	80	63	539	339	17	184	4%
Other	153	1	454	18	3	123	3%
Total	1,590	1,112	11,400	5,673	334	4,143	100%

Piceance basin

The Piceance basin is located in northwestern Colorado and is our largest area of concentrated development. During 2007 we operated an average of 25 drilling rigs in the basin. As of December 2007, 14 of these rigs were the new high efficiency rigs designed to drill up to 22 wells from one location. This area has approximately 1,760 undrilled proved locations in inventory. Within this basin we own and operate natural gas gathering facilities including some 280 miles of gathering lines and associated field compression. Approximately 88% of the gas gathered is our own equity production. The gathering system also includes six processing plants and associated treating facilities with a total capacity of 900,000 Mcfd. During 2007, these plants recovered approximately 54 million gallons of natural gas liquids (NGL's) which were marketed separately from the residue natural gas.

San Juan basin

The San Juan basin is located in northwest New Mexico and southwest Colorado.

Powder River basin

The Powder River basin is located in northeast Wyoming. The Powder River basin includes large areas with multiple coal seam potential, targeting thick coal bed methane formations at shallow depths. We have a significant inventory of undrilled locations, providing long-term drilling opportunities.

Mid-Continent properties

The Mid-Continent properties are located in the southeastern Oklahoma portion of the Arkoma basin and the Barnett Shale in the Fort Worth basin of Texas.

Other properties

Other properties are primarily comprised of interests in the Green River basin in southwestern Wyoming. Also included is exploration activity and other miscellaneous activity.

The following table summarizes our leased acreage as of December 31, 2007:

	Gross Acres	Net Acres
Developed	873,923	447,820
Undeveloped	1,211,865	627,393

Operating statistics

We focus on lower-risk development drilling. Our drilling success rate was 99 percent in 2007, 2006 and 2005. The following tables summarize domestic drilling activity by number and type of well for the periods indicated:

Number of Wells	Gross Wells	Net Wells
Development:		
Drilled		
2007	1,590	904
2006	1,783	954
2005	1,627	867
Successful		
2007	1,581	899
2006	1,770	948
2005	1,615	859

Because we currently have a low-risk drilling program in proven basins, the main component of risk that we manage is price risk. In February 2007, we entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Margin requirements, if any, under this new facility are dependent on the level of hedging with the banks and on natural gas reserves value. Exploration & Production natural gas hedges for 2008 domestic natural gas production consist of NYMEX fixed price contracts of 70 MMcf/d (whole year) and approximately 397 MMcf/d in regional collars (whole year). Our natural gas production hedges in 2007 consisted of 172 MMcf/d in NYMEX fixed price hedges and an additional 271 MMcf/d in NYMEX and basin level collars. A collar is an option contract that sets a gas price floor and ceiling for a certain volume of natural gas. Hedging decisions are made considering the overall Williams commodity risk exposure and are not executed independently by Exploration & Production; there are expected future gas purchases for other Williams entities which when taken as a net position may offset price risk related to Exploration & Production's expected future gas sales.

The following table summarizes our domestic sales and cost information for the years indicated:

	2007	2006	2005
Total net production sold (in Bcfe)	333.1	274.4	223.5
Average production costs including production taxes per thousand cubic feet of gas equivalent (Mcfe) produced	$ 0.98	$ 1.02	$ .92
Average sales price per Mcfe	$ 4.92	$ 5.24	$ 6.41
Realized impact of hedging contracts (Loss)	$ 0.16	$ (0.73)	$ (1.61)

Acquisitions & divestitures

Through transactions totaling approximately $77 million, Exploration & Production expanded its acreage position and purchased producing properties in the Fort Worth basin in north-central Texas and also expanded its acreage position in the Highlands area of the Piceance basin.

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production in Peru for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We will recognize a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received. As a result of the contract termination, we have no further interests associated with the crude oil concession. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

Other information

In 1993, Exploration & Production conveyed a net profits interest in certain of its properties to the Williams Coal Seam Gas Royalty Trust. Substantially all of the production attributable to the properties conveyed to the trust was from the Fruitland coal formation and constituted coal seam gas. We subsequently sold trust units to the public in an underwritten public offering and retained 3,568,791 trust units then representing 36.8 percent of outstanding trust units. We have previously sold trust units on the open market, with our last sales in June 2005. As of February 1, 2008, we own 789,291 trust units.

International exploration and production interests

We also have investments in international oil and gas interests. If combined with our domestic proved reserves, our international interests would make up approximately 3.6 percent of our total proved reserves.

Gas Pipeline

We own and operate, through Williams Gas Pipeline Company, LLC (WMZ) and its subsidiaries, a combined total of approximately 14,200 miles of pipelines with a total annual throughput of approximately 2,700 trillion British Thermal Units of natural gas and peak-day delivery capacity of approximately 12 MMdt of gas. Gas Pipeline consists of Transcontinental Gas Pipe Line Corporation and Northwest Pipeline GP. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 50 percent interest in Gulfstream Natural Gas System, L.L.C. Gas Pipeline also includes our new master limited partnership, Williams Pipeline Partners, L.P.

Transcontinental Gas Pipe Line Corporation (Transco)

Transco is an interstate natural gas transportation company that owns and operates a 10,300-mile natural gas pipeline system extending from Texas, Louisiana, Mississippi and the offshore Gulf of Mexico through Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania, and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 11 southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, New York, New Jersey, and Pennsylvania.

Pipeline system and customers

At December 31, 2007, Transco's system had a mainline delivery capacity of approximately 4.7 MMdt of natural gas per day from its production areas to its primary markets. Using its Leidy Line along with market-area storage and transportation capacity, Transco can deliver an additional 3.7 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.4 MMdt of natural gas per day. Transco's system includes 45 compressor stations, five underground storage fields, two liquefied natural gas (LNG) storage facilities. Compression facilities at a sea level-rated capacity total approximately 1.5 million horsepower.

Transco's major natural gas transportation customers are public utilities and municipalities that provide service to residential, commercial, industrial and electric generation end users. Shippers on Transco's system include public utilities, municipalities, intrastate pipelines, direct industrial users, electrical generators, gas marketers and producers. One customer accounted for approximately 12 percent of Transco's total revenues in 2007. Transco's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Transco's business. Additionally, Transco offers storage services and interruptible transportation services under short-term agreements.

Transco has natural gas storage capacity in five underground storage fields located on or near its pipeline system or market areas and operates three of these storage fields. Transco also has storage capacity in an LNG storage facility and operates the facility. The total usable gas storage capacity available to Transco and its customers in such underground storage fields and LNG storage facility and through storage service contracts is approximately 216 billion cubic feet of gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent ownership interest in Pine Needle LNG Company, LLC, an LNG storage facility with 4 billion cubic feet of storage capacity. Storage capacity permits Transco's customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Transco expansion projects

The pipeline projects listed below were completed during 2007 or are future pipeline projects for which we have customer commitments.

Potomac Expansion Project

In November 2007, we placed into service the Potomac Expansion Project, an expansion of our existing natural gas transmission system from receipt points in North Carolina to delivery points in the greater Baltimore and Washington, D.C. metropolitan areas. The second phase of the project involving installation of certain appurtenant facilities will be completed in fall 2008. The capital cost of the project is estimated to be approximately $88 million.

Leidy to Long Island Expansion Project

In December 2007, we placed into service the Leidy to Long Island Expansion Project, an expansion of our existing natural gas transmission system in Zone 6 from the Leidy Hub in Pennsylvania to Long Island, New York. The capital cost of the project is estimated to be approximately $169 million.

Sentinel Expansion Project

The Sentinel Expansion Project will involve an expansion of our existing natural gas transmission system from the Leidy Hub in Clinton County, Pennsylvania and from the Pleasant Valley interconnection with Cove Point LNG in Fairfax County, Virginia to various delivery points requested by the shippers under the project. The capital cost of the project is estimated to be up to approximately $169 million. Transco plans to place the project into service in phases, in late 2008 and late 2009.

Pascagoula Expansion Project

The Pascagoula Expansion Project will involve the construction of a new pipeline to be jointly owned with Florida Gas Transmission connecting Transco's existing Mobile Bay Lateral to the outlet pipeline of a proposed liquefied natural gas import terminal in Mississippi. Transco's share of the estimated capital cost of the project is up to $37 million. Transco plans to place the project into service in mid-2011.

Operating statistics

The following table summarizes transportation data for the Transco system for the periods indicated:

	2007	2006	2005
		(In trillion British Thermal Units)	
Market-area deliveries:			
Long-haul transportation	839	795	755
Market-area transportation	875	817	853
Total market-area deliveries	1,714	1,612	1,608
Production-area transportation	190	247	278
Total system deliveries	1,904	1,859	1,886
Average Daily Transportation Volumes	5.2	5.1	5.2
Average Daily Firm Reserved Capacity	6.6	6.6	6.6

Transco's facilities are divided into eight rate zones. Five are located in the production area, and three are located in the market area. Long-haul transportation involves gas that Transco receives in one of the production-area zones and delivers to a market-area zone. Market-area transportation involves gas that Transco both receives and delivers within the market-area zones. Production-area transportation involves gas that Transco both receives and delivers within the production-area zones.

Northwest Pipeline GP (Northwest Pipeline)

Northwest Pipeline is an interstate natural gas transportation company that owns and operates a natural gas pipeline system extending from the San Juan basin in northwestern New Mexico and southwestern Colorado through Colorado, Utah, Wyoming, Idaho, Oregon and Washington to a point on the Canadian border near Sumas, Washington. Northwest Pipeline provides services for markets in California, Arizona, New Mexico, Colorado, Utah, Nevada, Wyoming, Idaho, Oregon and Washington directly or indirectly through interconnections with other pipelines.

Pipeline system and customers

At December 31, 2007, Northwest Pipeline's system, having long-term firm transportation agreements with peaking capacity of approximately 3.4 MMdt of natural gas per day, was composed of approximately 3,900 miles of mainline and lateral transmission pipelines and 41 transmission compressor stations having a combined sea level-rated capacity of approximately 473,000 horsepower.

Northwest implemented new rates effective January 1, 2007 that were approved by FERC. The rate case settlement established that general system firm transportation rates on Northwest's system increased from $0.30760 to $0.40984 per Dth.

In 2007, Northwest Pipeline served a total of 132 transportation and storage customers. Transportation customers include distribution companies, municipalities, interstate and intrastate pipelines, gas marketers and direct industrial users. The two largest customers of Northwest Pipeline in 2007 accounted for approximately 20 percent and 11.5 percent, of its total operating revenues. No other customer accounted for more than 10 percent of Northwest Pipeline's total operating revenues in 2007. Northwest Pipeline's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Northwest Pipeline's business. Additionally, Northwest Pipeline offers interruptible and short-term firm transportation service.

As a part of its transportation services, Northwest Pipeline utilizes underground storage facilities in Utah and Washington enabling it to balance daily receipts and deliveries. Northwest Pipeline also owns and operates an LNG storage facility in Washington that provides service for customers during a few days of extreme demands. These storage facilities have an aggregate firm delivery capacity of approximately 600 million cubic feet of gas per day.

Northwest Pipeline expansion projects

The pipeline projects listed below were completed during 2007 or are future pipeline projects for which we have customer commitments.

Jackson Prairie Underground Expansion

The Jackson Prairie Storage Project, connected to Northwest's transmission system near Chehalis, Washington, is operated by Puget Sound Energy and is jointly owned by Northwest, Puget Sound Energy and Avista Corporation. A phased capacity expansion is currently underway and a deliverability expansion is planned for 2008. Northwest's one-third interest in the project includes 104 MMcf per day of planned 2008 deliverability expansion and approximately 1.2 Bcf of working natural gas storage capacity to be developed over approximately a four year period from 2007 through 2010. Northwest's one-third share of the cost of the deliverability expansion is estimated to be $16 million. Northwest's estimated capital cost for the capacity expansion component of the new storage service is $6.1 million, primarily for base natural gas.

Colorado Hub Connection Project

Northwest has proposed installing a new lateral to connect the White River Hub near Meeker, Colorado to Northwest's mainline near Sand Springs, Colorado. This project is referred to as the Colorado Hub

Connection, or CHC Project. It is estimated that the construction of the CHC Project would cost up to $53 million and could begin service as early as November 2009.

Parachute Lateral

Northwest placed its Parachute Lateral facilities in service on May 16, 2007, and began collecting revenues of approximately $0.87 million per month. The expansion increased capacity by 450 Mdt/d at a cost of approximately $86 million.

On August 24, 2007, Northwest filed an application with FERC to amend its certificate of public convenience and necessity issued for the Parachute Lateral to allow the transfer of the ownership of its Parachute Lateral facilities to a newly created entity, Parachute Pipeline LLC (Parachute), which is owned by Midstream through one of its wholly-owned subsidiaries Williams Field Services Company, LLC (Williams Field Services). This application was approved by FERC on November 15, 2007, and Northwest sold the Parachute on December 31, 2007. The Parachute Lateral facilities are located in Rio Blanco and Garfield counties, Colorado.

As contemplated in the application for amendment, Parachute has leased the facilities back to Northwest, and as a result of the sale has become a Midstream subsidiary. Northwest will continue to operate the facilities under the FERC certificate. When Midstream completes its Willow Creek Processing Plant, the lease (subject to further regulatory approval) will terminate, and Parachute will assume full operational control and responsibility for the Parachute Lateral.

Operating statistics

The following table summarizes volume and capacity data for the Northwest Pipeline system for the periods indicated:

	2007	2006	2005
	(In trillion British Thermal Units)		
Total Transportation Volume	757	676	673
Average Daily Transportation Volumes	2.1	1.9	1.8
Average Daily Reserved Capacity Under Long-Term Base Firm Contracts, excluding peak capacity	2.5	2.5	2.5
Average Daily Reserved Capacity Under Short-Term Firm Contracts(1)	.8	.9	.8

(1) Consists primarily of additional capacity created from time to time through the installation of new receipt or delivery points or the segmentation of existing mainline capacity. Such capacity is generally marketed on a short-term firm basis, because it does not involve the construction of additional mainline capacity.

Gulfstream Natural Gas System, L.L.C. (Gulfstream)

Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida. Gas Pipeline and Spectra Energy (formerly known as Duke Energy), through their respective subsidiaries, each holds a 50 percent ownership interest in Gulfstream and provides operating services for Gulfstream. At December 31, 2007, our equity investment in Gulfstream was $439 million.

Gulfstream expansion projects

Gulfstream has entered into a precedent agreement and a related firm transportation service agreement pursuant to which, subject to the receipt of all necessary regulatory approvals and other conditions precedent therein, Gulfstream intends to extend the pipeline system into South Florida and fully subscribe the remaining 345 Mdt/d of firm capacity on the existing pipeline system on a long-term basis. The estimated capital cost of this project is anticipated to be up to approximately $130 million, with Gas Pipeline’s share being 50 percent of such costs. Gulfstream also has executed a precedent agreement and a related firm transportation service agreement pursuant to which, subject to the receipt of all necessary regulatory approvals and other conditions precedent therein, it intends to construct and fully subscribe on a long-term basis the first incremental expansion of

Gulfstream's mainline capacity, increasing the current mainline capacity of 1.1 MMdt/d to 1.255 MMdt/d. The estimated capital cost of this expansion is anticipated to be up to approximately $153 million, with Gas Pipeline's share being 50 percent of such costs. No significant increase in operations personnel is expected as a result of these two projects.

Williams Pipeline Partners L.P

WMZ was formed to own and operate natural gas transportation and storage assets. We currently own approximately 45.7 percent limited partnership interest and a 2 percent general partner interest in WMZ. WMZ provides us with lower cost of capital that is expected to enable growth of our Gas Pipeline business. WMZ also creates a vehicle to monetize our qualifying assets. Such transactions, which are subject to approval by the boards of directors of Williams and WMZ's general partner, allow us to retain control of the assets through our ownership interest in WMZ. A subsidiary of ours serves as the general partner of WMZ. The initial asset of WMZ is a 35 percent interest in Northwest Pipeline.

Midstream Gas & Liquids

Our Midstream segment, one of the nation's largest natural gas gatherers and processors, has primary service areas concentrated in the major producing basins in Colorado, New Mexico, Wyoming, the Gulf of Mexico, Venezuela and western Canada. Midstream's primary businesses — natural gas gathering, treating, and processing; NGL fractionation, storage and transportation; and oil transportation — fall within the middle of the process of taking natural gas and crude oil from the wellhead to the consumer. NGLs, ethylene and propylene are extracted/produced at our plants, including our Canadian and Gulf Coast olefins plants. These products are used primarily for the manufacture of plastics, home heating and refinery feedstock.

Although most of our gas services are performed for a volumetric-based fee, a portion of our gas processing contracts are commodity-based and include two distinct types of commodity exposure. The first type includes "Keep Whole" processing contracts whereby we own the rights to the value from NGLs recovered at our plants and have the obligation to replace the lost heating value with natural gas. Under these contracts, we are exposed to the spread between NGLs and natural gas prices. The second type consists of "Percent of Liquids" contracts whereby we receive a portion of the extracted liquids with no direct exposure to the price of natural gas. Under these contracts, we are only exposed to NGL price movements.

Our Canadian and Gulf Liquids olefin facilities have commodity price exposure. In Canada, we are exposed to the spread between the price for natural gas and the olefinic products we produce. In the Gulf Coast, our feedstock for the ethane cracker is ethane and propane; as a result, we are exposed to the price spread between ethane and propane and ethylene and propylene. In the Gulf Coast, we also purchase refinery grade propylene and fractionate it into polymer grade propylene and propane; as a result we are exposed to the price spread between those commodities.

Key variables for our business will continue to be:

- retaining and attracting customers by continuing to provide reliable services;
- revenue growth associated with additional infrastructure either completed or currently under construction;
- disciplined growth in our core service areas;
- prices impacting our commodity-based processing and olefin activities.

Gathering and processing

We own and/or operate domestic gas gathering and processing assets primarily within the western states of Wyoming, Colorado and New Mexico, and the onshore and offshore shelf and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi and Alabama. These assets consist of approximately 8,700 miles of gathering pipelines, nine processing plants (one partially owned) and five natural gas treating plants with a combined daily inlet capacity of nearly 6.5 billion cubic feet per day. Some of these assets are owned through our interest in WPZ (see William Partners L.P. section below).

Geographically, our Midstream natural gas assets are positioned to maximize commercial and operational synergies with our other assets. For example, most of our offshore gathering and processing assets attach and process or condition natural gas supplies delivered to the Transco pipeline. Also, our gathering and processing facilities in the San Juan Basin handle about 85 percent of our Exploration & Production group's wellhead production in this basin. Both our San Juan Basin and Southwest Wyoming systems deliver gas volumes into Northwest Pipeline's interstate system in addition to third party interstate systems.

Included in the natural gas assets listed above are the assets of Discovery Producer Services LLC and its subsidiary Discovery Gas Transmission Services LLC (Discovery). WPZ owns a partial interest in Discovery and we operate its facilities. Discovery's assets include a cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana and an offshore natural gas gathering and transportation system in the Gulf of Mexico.

In addition to these natural gas assets, we own and operate three crude oil pipelines totaling approximately 310 miles with a capacity of more than 300,000 barrels per day. This includes our Mountaineer, Alpine and BANJO crude oil pipeline systems in the deepwater Gulf of Mexico.

The BANJO oil pipeline and Seahawk gas pipeline run parallel and deliver production across two producer-owned spar-type floating production systems from the Anadarko Petroleum Corporation (Anadarko) operated Boomvang and Nansen field areas in the western Gulf of Mexico. These pipelines were placed in service in 2002.

Our 18 inch oil pipeline, Alpine, which became operational in 2003, is our second western gulf crude oil pipeline. The pipeline extends 96 miles from Garden Banks Block 668 in the central Gulf of Mexico to our shallow-water platform at Galveston Area Block A244. From this platform, the oil is delivered onshore through ExxonMobil's Hoover Offshore Oil Pipeline System under a joint tariff agreement. This production is coming from the Gunnison field, which is located in 3,150 feet of water and operated by Anadarko.

Our Devils Tower floating production system and associated pipelines were placed in service in 2004. Initially built to serve the Devils Tower field, the floating production system is located in Mississippi Canyon Block 773, approximately 150 miles south-southwest of Mobile, Alabama. During the fourth quarter of 2005, the platform's service expanded to include tie-backs of production from the Triton and Goldfinger fields in addition to the host Devils Tower field. Construction is currently underway to add topside capacity for the recently dedicated Bass Lite gas discovery. Full field production from Bass Lite is expected mid-year 2008. Located in 5,610 feet of water, it is the world's deepest dry tree spar. The platform, which is operated by ENI Petroleum on our behalf, is capable of producing 60 MMcf/d of natural gas and 60 Mbbls/d of oil.

The Devils Tower project includes gas and oil pipelines. The 139-mile Canyon Chief gas pipeline consists of 18-inch diameter pipe. The 155-mile Mountaineer oil pipeline is a combination of 18- and 20-inch diameter pipe. The gas is delivered into Transco's pipeline, and processed at our Mobile Bay plant to recover the NGLs. The oil is transported to ChevronTexaco's Empire Terminal in Plaquemines Parish, Louisiana. These associated pipelines are significantly oversized relative to the Devils Tower spar top-side capacity.

Gulf Coast petrochemical and olefins

We own a 10/12 interest in and are the operator for an ethane cracker at Geismar, Louisiana, with a total production capacity of 1.3 billion pounds per year of ethylene. In July 2007, we exercised our right of first refusal to acquire BASF's 5/12th ownership interest in the Geismar olefins facility bringing our ownership position up to the current 10/12 interest. We also own an ethane pipeline system and a propylene splitter and its related pipeline system in Louisiana.

Canada

Our Canadian operations include an olefin liquids extraction plant located near Ft. McMurray, Alberta and an olefin fractionation facility near Edmonton, Alberta. Our facilities extract olefinic liquids from the off-gas produced from third party oil sands bitumen upgrading and then fractionate, treat, store, terminal and sell the propane, propylene, butane and condensate recovered from this process. We continue to be the only olefins fractionator in Western Canada and the only treater-processor of oil sands upgrader off-gas. These operations extract valuable petrochemical feedstocks from upgrader off-gas streams allowing the upgraders to burn cleaner natural gas streams and reduce overall air emissions. The extraction plant has processing capacity in excess of 100 MMcf/d with the ability to recover in excess of 15 Mbbls/d of olefin and NGL products.

Venezuela

Our Venezuelan investments involve gas compression and gas processing and natural gas liquids fractionation operations. We own controlling interests and operate three gas compressor facilities which provide roughly 70 percent of the gas injections in eastern Venezuela. These facilities help stabilize the reservoir and enhance the recovery of crude oil by re-injecting natural gas at high pressures. We also own a 49.25 percent interest in two 400 MMcf/d natural gas liquids extraction plants, a 50,000 barrels per day natural gas liquids fractionation plant and associated storage and refrigeration facilities.

Other

We own interests in and/or operate NGL fractionation and storage assets. These assets include two partially owned NGL fractionation facilities near Conway, Kansas and Baton Rouge, Louisiana that have a combined capacity in excess of 167,000 barrels per day. We also own approximately 20 million barrels of NGL storage capacity in central Kansas. Some of these assets are owned through our interest in WPZ.

We also own a 14.6% interest in Aux Sable Liquid Products and its Channahon, Illinois gas processing and NGL fractionation facility near Chicago. The facility is capable of processing up to 2.1 Bcf/d of natural gas from the Alliance Pipeline system and fractionating approximately 87,000 barrels per day of extracted liquids into NGL products.

Williams Partners L.P (WPZ)

WPZ was formed to engage in the business of gathering, transporting and processing natural gas and fractionating and storing NGLs. We currently own approximately a 21.6 percent limited partnership interest and a 2 percent general partner interest in WPZ. WPZ provides us with lower cost of capital that is expected to enable growth of our Midstream business. WPZ also creates a vehicle to monetize our qualifying assets. Such transactions, which are subject to approval by the boards of directors of both Williams and WPZ's general partner, allow us to retain control of the assets through our ownership interest in WPZ.

WPZ's asset portfolio at its initial public offering in 2005 consisted of a 40 percent interest in Discovery, the Carbonate Trend gathering pipeline, three integrated NGL storage facilities near Conway, Kansas and a 50 percent interest in an NGL fractionator near Conway, Kansas.

During 2006, WPZ acquired Williams Four Corners, LLC which owns a 3,500-mile natural gas gathering system in the San Juan Basin in New Mexico and Colorado with capacity of nearly 2 Bcf/d; the Ignacio natural gas processing plant in Colorado and the Kutz and Lybrook natural gas processing plants in New Mexico, which have a combined processing capacity of 760 MMcf/d; and the Milagro and Esperanza natural gas treating plants in New Mexico, which are designed to remove carbon dioxide from up to 750 MMcf of natural gas per day.

In June 2007, WPZ acquired an additional 20 percent interest in Discovery. WPZ now owns a 60 percent interest in the Discovery gathering, transportation, processing and NGL fractionation system, the remainder of which is owned by third parties.

In December 2007, WPZ acquired certain ownership interests in Wamsutter LLC from us for $750 million. Wamsutter LLC owns a 1,700 mile natural gas gathering system in the Washakie Basin in south-central Wyoming and the Echo Springs natural gas processing plant in Sweetwater County, Wyoming.

Expansion projects

Gathering and processing — west

During the first quarter of 2007, we completed construction at our existing gas processing complex located near Opal, Wyoming, to add a fifth cryogenic gas processing train capable of processing up to 350 MMcf/d, bringing total Opal capacity to approximately 1.5 Bcf/d. This plant expansion increased Opal's processing capacity by more than 30 percent and became operational during the first quarter.

In the first quarter of 2007, we also announced plans to construct and operate the Willow Creek facility a 450 MMcf/d natural gas processing plant in the Piceance Basin of western Colorado, where Exploration and Production has its most significant volume of natural gas production, reserves and development activity. Exploration and Production's existing Piceance Basin processing plants are primarily designed to condition the natural gas to meet quality specifications for pipeline transmission, not to maximize the extraction of NGLs. We expect the new Willow Creek facility to recover 25,000 barrels per day of NGLs at startup, which is expected to be in the third quarter of 2009.

In December 2007, Midstream purchased the Parachute Lateral system from Gas Pipeline. The system is a 37.6-mile expansion, originally placed in service by Gas Pipelines in May 2007, and provides capacity of 450 Mdt/d through a 30-inch diameter line, transporting residue gas from the Piceance basin to the Greasewood Hub in northwest Colorado. The Willow Creek facility will straddle the Parachute Lateral pipeline and will process gas flowing through the pipeline. In an arrangement approved by the FERC, Midstream will lease the pipeline to Gas Pipeline, who will continue to operate the pipeline until completion of a planned FERC abandonment filing.

In addition, Midstream acquired an existing natural gas pipeline from Gas Pipeline, and has begun the process of converting it from natural gas to NGL service and constructing additional pipeline to create a pipeline alternative for NGLs currently being transported by truck from Exploration & Production's existing Piceance basin processing plants to a major NGL transportation pipeline system.

In 2006, we entered into an agreement to develop new pipeline capacity for transporting NGLs from production areas in southwestern Wyoming to central Kansas. The other party to the agreement reimbursed us for the development costs we had incurred for the proposed pipeline and acquired 99 percent of the pipeline, known as Overland Pass Pipeline Company, LLC. We retained a 1 percent interest and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational. Start-up is planned for mid-2008. Additionally, we have agreed to dedicate our equity NGL volumes from our two Wyoming plants and the new Willow Creek facility for transport under a long-term shipping agreement. The terms represent significant savings compared with the existing tariff and other alternatives considered.

Gathering and processing — deepwater projects

The deepwater Gulf continues to be an attractive growth area for our Midstream business. Since 1997, we have invested almost $1.3 billion in new midstream assets in the Gulf of Mexico. These facilities provide both onshore and offshore services through pipelines, platforms and processing plants. The new facilities could also attract incremental gas volumes to Transco's pipeline system in the southeastern United States.

During 2007, we have continued construction activities on the Perdido Norte project which includes oil and gas lines that would expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. In addition, we completed agreements with certain producers to provide gathering, processing and transportation services over the life of the reserves. We also intend to expand our onshore Markham gas processing facility to adequately serve this new gas production. The scale of the project has increased to include additional pipeline and more efficient processing capacity and is now estimated to cost approximately $560 million and to be in service in the third quarter of 2009.

Chevron and Anadarko are dedicating to us the transport of production from their current and future ownership in a defined area surrounding the Blind Faith discovery in the deepwater Gulf of Mexico. To accommodate production from the Blind Faith acreage and the surrounding blocks, we have agreed to extend our Canyon Chief and Mountaineer pipelines to the producer-owned floating production facility. We expect to have the extensions ready for service in the second quarter of 2008. The approximately $250 million project will facilitate a 37-mile extension of each pipeline. The agreement also creates opportunities for us to move natural gas from the Blind Faith discovery through our Mobile Bay, Alabama, processing plant and our Transco and Gulfstream interstate pipeline systems. Recovered NGLs from Blind Faith also could be fractionated at our facilities in Baton Rouge or Paradis, Louisiana.

Customers and operations

Our domestic gas gathering and processing customers are generally natural gas producers who have proved and/or producing natural gas fields in the areas surrounding our infrastructure. During 2007, these operations gathered and processed gas for approximately 215 gas gathering and processing customers. Our top three gathering and processing customers accounted for about 45 percent of our domestic gathering and processing revenue. Our gathering and processing agreements are generally long-term agreements.

In addition to our gathering and processing operations, we market NGLs and petrochemical products to a wide range of users in the energy and petrochemical industries. We provide these products to third parties from the production at our domestic facilities. The majority of domestic sales are based on supply contracts of less than one year in duration. The production from our Canadian facilities is marketed in Canada and in the United States.

Our Venezuelan assets were constructed and are currently operated for the exclusive benefit of Petróleos de Venezuela S.A under long-term contracts. These significant contracts have a remaining term between 10 and 14 years and our revenues are based on a combination of fixed capital payments, throughput volumes, and, in the case of one of the gas compression facilities, a minimum throughput guarantee. The Venezuelan government has continued its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and continues to publicly declare that additional energy contracts will be unilaterally amended and privately held assets will be expropriated, escalating our concern regarding political risk in Venezuela.

Operating statistics

The following table summarizes our significant operating statistics for Midstream:

	2007	2006	2005
Volumes(1):			
Domestic Gathering (trillion British Thermal Units)	1,045	1,181	1,253
Domestic Natural Gas Liquid Production (Mbbls/d)(2)	163	152	144
Crude Oil Gathering (Mbbls/d)(2)	80	86	88
Processing Volumes (trillion British Thermal Units)	937	833	721

(1) Excludes volumes associated with partially owned assets that are not consolidated for financial reporting purposes.

(2) Annual Average Mbbls/d

Gas Marketing Services

Gas Marketing Services 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. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, and provides services to third-parties, such as producers.

Gas Marketing Services' natural gas sales volumes, including sales volumes to other segments, were 2.3 Bcf/d, 2.1 Bcf/d and 2.1 Bcf/d for the years ending December 31, 2007, 2006 and 2005, respectively. Gas Marketing Services' natural gas purchase volumes, including purchases from other segments, were 2.4 Bcf/d, 2.3 Bcf/d and 2.2 Bcf/d for the same periods.

As of December 31, 2007, Gas Marketing Services has approximately 159 customers compared with approximately 163 customers at the end of 2006.

Our Exploration and Production and Midstream segments may execute commodity hedges with Gas Marketing Services. In turn, Gas Marketing Services may execute offsetting derivative contracts with unrelated third parties.

As a result of the sale of a substantial portion of our Power business in the fourth quarter of 2007, Gas Marketing Services also is responsible for certain remaining legacy natural gas contracts and positions. We intend to liquidate a substantial portion of these legacy contracts. During 2007, we substantially reduced the overall legacy positions remaining. Until such legacy positions are liquidated, segment results may experience 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. However, this mark-to-market volatility is expected to be significantly reduced compared to previous levels.

Other

At December 31, 2007, we owned approximately 99.3 percent of the Class B Interests in Longhorn Partners Pipeline LP (Longhorn), which owned a refined petroleum products pipeline from Houston, Texas to El Paso, Texas. The Class B Interests are preferred interests but subordinate to other preferred interests, and the common interests are subordinate to both. It is uncertain whether we will ever receive any payments related to our Class B Interests or our common interests, however any such amounts related to these interests were fully impaired in 2005, and will only be recognized as income when received.

We continue to receive payments associated with the 2005 transfer of the First Amended and Restated Pipeline Operating Services Agreement to a third party. The management of Longhorn completed an installment sale of the pipeline during the third quarter of 2006. The sale of the pipeline did not impact these ongoing payments which are recognized as income when received.

Additional Business Segment Information

Our ongoing business segments are accounted for as continuing operations in the accompanying financial statements and notes to financial statements included in Part II.

Operations related to certain assets in “Discontinued Operations” have been reclassified from their traditional business segment to “Discontinued Operations” in the accompanying financial statements and notes to financial statements included in Part II.

Our corporate parent company performs certain management, legal, financial, tax, consultative, information technology, administrative and other services for our subsidiaries.

Our corporate parent company’s principal sources of cash are from external financings, dividends and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, sales of master partnership units to the public, interest payments from subsidiaries on cash advances and net proceeds from asset sales. The amount of dividends available to us from subsidiaries largely depends upon each subsidiary’s earnings and operating capital requirements. The terms of certain of our subsidiaries’ borrowing arrangements limit the transfer of funds to our corporate parent.

We believe that we have adequate sources and availability of raw materials and commodities for existing and anticipated business needs. In support of our energy commodity activities, primarily conducted through Gas Marketing Services, our counterparties require us to provide various forms of credit support such as margin, adequate assurance amounts and pre-payments for gas supplies. Our pipeline systems are all regulated in various ways resulting in the financial return on the investments made in the systems being limited to standards permitted by the regulatory agencies. Each of the pipeline systems has ongoing capital requirements for efficiency and mandatory improvements, with expansion opportunities also necessitating periodic capital outlays.

REGULATORY MATTERS

Exploration & Production. Our Exploration & Production business is subject to various federal, state and local laws and regulations on taxation and payment of royalties, and the development, production and marketing of oil and gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Such laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our reserves.

Gas Pipeline. Gas Pipeline's interstate transmission and storage activities are subject to FERC regulation under the Natural Gas Act of 1938 (NGA) and under the Natural Gas Policy Act of 1978, and, as such, its rates and charges for the transportation of natural gas in interstate commerce, its accounting, and the extension, enlargement or abandonment of its jurisdictional facilities, among other things, are subject to regulation. Each gas pipeline company holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities and properties for which certificates are required under the NGA. Each gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. FERC Standards of Conduct govern how our interstate pipelines communicate and do business with their marketing affiliates. Among other things, the Standards of Conduct require that interstate pipelines not operate their systems to preferentially benefit their marketing affiliates.

Each of our interstate natural gas pipeline companies establishes its rates primarily through the FERC's ratemaking process. Key determinants in the ratemaking process are:

- costs of providing service, including depreciation expense;
- allowed rate of return, including the equity component of the capital structure and related income taxes;
- volume throughput assumptions.

The allowed rate of return is determined in each rate case. Rate design and the allocation of costs between the demand and commodity rates also impact profitability. As a result of these proceedings, certain revenues previously collected may be subject to refund.

Midstream. For our Midstream segment, onshore gathering is subject to regulation by states in which we operate and offshore gathering is subject to the Outer Continental Shelf Lands Act (OCSLA). Of the states where Midstream gathers gas, currently only Texas actively regulates gathering activities. Texas regulates gathering primarily through complaint mechanisms under which the state commission may resolve disputes involving an individual gathering arrangement. Although gathering facilities located offshore are not subject to the NGA (although offshore transmission pipelines may be), some controversy exists as to how the FERC should determine whether offshore facilities function as gathering. These issues are currently before the FERC. Most gathering facilities offshore are subject to the OCSLA, which provides in part that outer continental shelf pipelines "must provide open and nondiscriminatory access to both owner and non-owner shippers."

Midstream also owns interests in and operates two offshore transmission pipelines that are regulated by the FERC because they are deemed to transport gas in interstate commerce. Black Marlin Pipeline Company provides transportation service for offshore Texas production in the High Island area and redelivers that gas to intrastate pipeline interconnects near Texas City. Discovery provides transportation service for offshore Louisiana production from the South Timbalier, Grand Isle, Ewing Bank and Green Canyon (deepwater) areas to an onshore processing facility and downstream interconnect points with major interstate pipelines. FERC regulation requires all terms and conditions of service, including the rates charged, to be filed with and approved by the FERC before any changes can go into effect. In 2007, Black Marlin filed and settled a major rate change application before the FERC resulting in increased rates for service. In November 2007, Discovery filed a settlement in lieu of a rate change filing that if approved would increase its rates for service.

Our remaining Midstream Canadian assets are regulated by the Alberta Energy & Utilities Board (AEUB) and Alberta Environment. The regulatory system for the Alberta oil and gas industry incorporates a large measure of self-regulation, providing that licensed operators are held responsible for ensuring that their operations are conducted in accordance with all provincial regulatory requirements. For situations in which non-compliance with the applicable regulations is at issue, the AEUB and Alberta Environment have implemented an enforcement process with escalating consequences.

Gas Marketing Services. Our Gas Marketing business is subject to a variety of laws and regulations at the local, state and federal levels, including the FERC and the Commodity Futures Trading Commission regulations. In addition, natural gas markets continue to be subject to numerous and wide-ranging federal and state regulatory proceedings and investigations. We are also subject to various federal and state actions and investigations regarding, among other things, market structure, behavior of market participants, market prices, and reporting to trade publications. We may be liable for refunds and other damages and penalties as a result of ongoing actions and investigations. The outcome of these matters could affect our creditworthiness and ability to perform contractual obligations as well as other market participants' creditworthiness and ability to perform contractual obligations to us.

See Note 15 of our Notes to Consolidated Financial Statements for further details on our regulatory matters.

ENVIRONMENTAL MATTERS

Our generation facilities, processing facilities, natural gas pipelines, and exploration and production operations are subject to federal environmental laws and regulations as well as the state and tribal laws and regulations adopted by the jurisdictions in which we operate. We could incur liability to governments or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil, or water, as well as liability for clean up costs. Materials could be released into the environment in several ways including, but not limited to:

- from a well or drilling equipment at a drill site;
- leakage from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and gas wells resulting from accidents during normal operations;
- blowouts, cratering and explosions.

Because the requirements imposed by environmental laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition we may be liable for environmental damage caused by former operators of our properties.

We believe compliance with environmental laws and regulations will not have a material adverse effect on capital expenditures, earnings or competitive position. However, environmental laws and regulations could affect our business in various ways from time to time, including incurring capital and maintenance expenditures, fines and penalties, and creating the need to seek relief from the FERC for rate increases to recover the costs of certain capital expenditures and operation and maintenance expenses.

For a discussion of specific environmental issues, see "Environmental" under Management's Discussion and Analysis of Financial Condition and Results of Operations and "Environmental Matters" in Note 15 of our Notes to Consolidated Financial Statements.

COMPETITION

Exploration & Production. Our Exploration & Production segment competes with other oil and gas concerns, including major and independent oil and gas companies in the development, production and marketing of natural gas. We compete in areas such as acquisition of oil and gas properties and obtaining necessary equipment, supplies and services. We also compete in recruiting and retaining skilled employees.

Gas Pipeline. The natural gas industry has undergone significant change over the past two decades. A highly-liquid competitive commodity market in natural gas and increasingly competitive markets for natural gas services, including competitive secondary markets in pipeline capacity, have developed. As a result, pipeline capacity is being used more efficiently, and peaking and storage services are increasingly effective substitutes for annual pipeline capacity.

Local distribution company (LDC) and electric industry restructuring by states have affected pipeline markets. Pipeline operators are increasingly challenged to accommodate the flexibility demanded by customers and allowed under tariffs, but the changes implemented at the state level have not required renegotiation of LDC contracts. The state plans have in some cases discouraged LDCs from signing long-term contracts for new capacity.

Several states are considering re-regulation and extending price caps because many regulators and legislators believe that deregulation has not worked. States are in the process of developing new energy plans that may require utilities to encourage energy saving measures and diversify their energy supplies to include renewable sources. This could lower the growth of gas demand.

These factors have increased the risk that customers will reduce their contractual commitments for pipeline capacity. Future utilization of pipeline capacity will also depend on competition from LNG imported into markets and new pipelines from the Rockies and other new producing areas, many of which are utilizing master limited partnership structures with a lower cost of capital, and on growth of natural gas demand.

Midstream. In our Midstream segment, we face regional competition with varying competitive factors in each basin. Our gathering and processing business competes with other midstream companies, interstate and intrastate pipelines, producers and independent gatherers and processors. We primarily compete with five to ten companies across all basins in which we provide services. Numerous factors impact any given customer's choice of a gathering or processing services provider, including rate, location, term, timeliness of services to be provided, pressure obligations and contract structure. We also compete in recruiting and retaining skilled employees. In 2005 we formed WPZ to help compete against other master limited partnerships for midstream projects. By virtue of the master limited partnership structure, WPZ provides us with an alternative and low-cost source of capital. We expect the alternative, low-cost capital will allow WPZ to compete favorably from a cost of capital perspective with other MLPs when pursuing acquisition opportunities of gathering and processing assets.

Gas Marketing Services. In our Gas Marketing Services segment, we compete directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities, and natural gas producers. We also compete with brokerage houses, energy hedge funds and other energy-based companies offering similar services.

EMPLOYEES

At February 1, 2008, we had approximately 4,319 full-time employees including 898 at the corporate level, 681 at Exploration & Production, 1,732 at Gas Pipeline, 984 at Midstream, and 24 at Gas Marketing Services. None of our employees are represented by unions or covered by collective bargaining agreements.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Note 17 of our Notes to Consolidated Financial Statements for amounts of revenues during the last three fiscal years from external customers attributable to the United States and all foreign countries. Also see Note 17 of our Notes to Consolidated Financial Statements for information relating to long-lived assets during the last three fiscal years, located in the United States and all foreign countries.

Item 1A. *Risk Factors*

FORWARD-LOOKING STATEMENTS/RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

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 those 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 which 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,” “scheduled” or similar 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;
- business strategy;
- estimates of proved gas and oil reserves;
- reserve potential;
- development drilling potential;
- cash flow from operations or results of operations;
- seasonality of certain business segments;
- natural gas and natural gas liquids prices and demand.

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 document. Many of the factors that will determine these results are beyond our ability to control or project. 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 and estimating future natural gas reserves), market demand, volatility of prices, and increased costs of capital;
- inflation, interest rates, fluctuation in foreign exchange, and general economic conditions;
- 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;
- changes in the current geopolitical situation;
- risks related to strategy and financing, including restrictions stemming from our debt agreements and future changes in our credit ratings;
- risks associated with future weather conditions;
- acts of terrorism.

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 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. These factors include the following:

RISK FACTORS

You should carefully consider the following risk factors in addition to the other information in this report. Each of these factors could adversely affect our business, operating results, and financial condition as well as adversely affect the value of an investment in our securities.

Risks Inherent to our Industry and Business

The long-term financial condition of our natural gas transportation and midstream businesses is dependent on the continued availability of natural gas supplies in the supply basins that we access, demand for those supplies in our traditional markets, and market demand for natural gas.

The development of the additional natural gas reserves that are essential for our gas transportation and midstream businesses to thrive requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to our pipeline systems. Low prices for natural gas, regulatory limitations, or the lack of available capital for these projects could adversely affect the development and production of additional reserves, as well as gathering, storage, pipeline transportation and import and export of natural gas supplies, adversely impacting our ability to fill the capacities of our gathering, transportation and processing facilities. Additionally, in some cases, new LNG import facilities built near our markets could result in less demand for our gathering and transportation facilities.

Estimating reserves and future net revenues involves uncertainties. Negative revisions to reserve estimates and oil and gas price declines may lead to decreased earnings, losses or impairment of oil and gas assets, including related goodwill.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Reserves that are “proved reserves” are those estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions, but should not be considered as a guarantee of results for future drilling projects.

The process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. The reserve data included in this report represent estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct over time.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil and gas prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. The revisions may also be sufficient to trigger impairment losses on certain properties which would result in a further non-cash charge to earnings. The revisions could also possibly affect the evaluation of Exploration & Production’s goodwill for impairment purposes.

Our past success rate for drilling projects and the historic performance of our exploration and production business is no predictor of future performance.

Our past success rate for drilling projects in 2007 should not be considered a predictor of future performance.

Performance of our exploration and production business is affected in part by factors beyond our control (any of which could cause the results of this business to decrease materially), such as:

- regulations and regulatory approvals;
- availability of capital for drilling projects which may be affected by other risk factors discussed in this report;
- cost-effective availability of drilling rigs and necessary equipment;
- availability of skilled labor;
- availability of cost-effective transportation for products;
- market risks (including price risks and competition) discussed in this report.

Our drilling, production, gathering, processing and transporting activities involve numerous risks that might result in accidents, and other operating risks and hazards.

Our operations are subject to all the risks and hazards typically associated with the development and exploration for, and the production and transportation of oil and gas. These operating risks include, but are not limited to:

- blowouts, cratering and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- fires;
- formations with abnormal pressures;
- pollution and other environmental risks;
- natural disasters.

In addition, there are inherent in our gas gathering, processing and transporting properties a variety of hazards and operating risks, such as leaks, spills, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. The location of certain segments of our pipelines in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In spite of our precautions, an event could cause considerable harm to people or property, and could have a material adverse effect on our financial condition, particularly if the event is not fully covered by insurance. Accidents or other operating risks could further result in loss of service available to our customers. Such circumstances could materially impact our ability to meet contractual obligations and retain customers, with a resulting impact on our results of operations.

Costs of environmental liabilities and complying with existing and future environmental regulations 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 for 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.

Changes in federal laws or regulations could reduce the availability or increase the cost of our interstate pipeline capacity or gas supply, and thereby reduce our earnings. Congress and certain states have for some time been considering various forms of legislation related to greenhouse gas emissions. There is a possibility that, when and if enacted, the final form of such legislation could increase our costs of compliance with environmental laws.

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.

Our operating results for certain segments of our business might fluctuate on a seasonal and quarterly basis.

Revenues from certain segments of our business can have seasonal characteristics. In many parts of the country, demand for natural gas and other fuels peaks during the winter. As a result, our overall operating results in the future might fluctuate substantially on a seasonal basis. Demand for natural gas and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and pipeline systems and the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns. Additionally, changes in the price of natural gas could benefit one of our business units, but disadvantage another. For example, our Exploration & Production business may benefit from higher natural gas prices, and Midstream, which uses gas as a feedstock, may not.

Risks Related to the Current Geopolitical Situation

Our investments and projects located outside of the United States expose us to risks related to the laws of other countries, and the taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. These risks might delay or reduce our realization of value from our international projects.

We currently own and might acquire and/or dispose of material energy-related investments and projects outside the United States. The economic and political conditions in certain countries where we have interests or in which we might explore development, acquisition or investment opportunities present risks of delays in construction and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments could make it more difficult to obtain non-recourse project financing or other financing on suitable terms, could adversely affect the ability of certain customers to honor their obligations with respect to such projects or investments and could impair our ability to enforce our rights under agreements relating to such projects or investments. Recent events in certain South American countries, particularly the continued threat of nationalization of certain energy-related assets in Venezuela, could have a material negative impact on our results of operations. We may not receive adequate compensation, or any compensation, if our assets in Venezuela are nationalized.

Operations and investments in foreign countries also can present currency exchange rate and convertibility, inflation and repatriation risk. In certain situations under which we develop or acquire projects or make investments, economic and monetary conditions and other factors could affect our ability to convert to U.S. dollars our earnings denominated in foreign currencies. In addition, risk from fluctuations in currency exchange rates can arise when our foreign subsidiaries expend or borrow funds in one type of currency, but receive revenue in another. In such cases, an adverse change in exchange rates can reduce our ability to meet expenses, including debt service obligations. We may or may not put contracts in place designed to mitigate our foreign currency exchange risks. We have some exposures that are not hedged and which could result in losses or volatility in our results of operations.

Risks Related to Strategy and Financing

Our debt agreements impose restrictions on us that may adversely affect our ability to operate our business.

Certain of our debt agreements contain covenants that restrict or limit among other things, our ability to create liens, sell assets, make certain distributions, repurchase equity and incur additional debt. In addition, our debt agreements contain, and those we enter into in the future may contain, financial covenants and other limitations with which we will need to comply. Our ability to comply with these covenants may be affected by many events beyond our control, and we cannot assure you that our future operating results will be sufficient to comply with the covenants or, in the event of a default under any of our debt agreements, to remedy that default.

Our failure to comply with the covenants in our debt agreements and other related transactional documents could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. An event of default or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements.

A downgrade of our current credit ratings could impact our costs of doing business in certain ways and maintaining current credit ratings is within the control of independent third parties.

A downgrade of our credit rating might increase our cost of borrowing. Our ability to access capital markets could also be limited by a downgrade of our credit rating and other disruptions. Such disruptions could include:

- economic downturns;
- deteriorating capital market conditions generally;
- declining market prices for natural gas, natural gas liquids and other commodities;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies;
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. Given the significant changes in capital markets and the energy industry over the last few years, credit rating agencies continue to review the criteria for attaining investment grade ratings and make changes to those criteria from time to time. Our corporate family credit rating and the credit ratings of Transco and Northwest Pipeline were raised to investment grade in 2007 by Standard & Poor's, Moody's Corporation, and Fitch Ratings, Ltd., and our senior unsecured debt ratings were raised to investment grade by Moody's and Fitch. No assurance can be given that the credit rating agencies will assign us investment grade ratings even if we meet or exceed their criteria for investment grade ratios or that our senior unsecured debt rating will be raised to investment grade by all of the credit rating agencies.

Prices for natural gas liquids, natural gas and other commodities are volatile and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain existing businesses.

Our revenues, operating results, future rate of growth and the value of certain segments of our businesses depend primarily upon the prices we receive for natural gas liquids, natural gas, or other commodities, and the differences between prices of these commodities. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital.

The markets for natural gas liquids, natural gas and other commodities are likely to continue to be volatile. Wide fluctuations in prices might result from relatively minor changes in the supply of and demand for these commodities, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of and demand for natural gas, natural gas liquids, petroleum, and related commodities;
- turmoil in the Middle East and other producing regions;
- the activities of the Organization of Petroleum Exporting Countries;
- terrorist attacks on production or transportation assets;
- weather conditions;
- the level of consumer demand;
- the price and availability of other types of fuels;
- the availability of pipeline capacity;
- supply disruptions, including plant outages and transportation disruptions;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- volatility in the natural gas markets;
- the overall economic environment;
- the credit of participants in the markets where products are bought and sold;
- the adoption of regulations or legislation relating to climate change.

We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets.

Our portfolio of derivative and other energy contracts consists of wholesale contracts to buy and sell commodities, including contracts for natural gas, natural gas liquids and other commodities that are settled by the delivery of the commodity or cash throughout the United States. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. In the past, certain marketing and trading companies have experienced severe financial problems due to price volatility in the energy commodity markets. In certain instances this volatility has caused companies to be unable to deliver energy commodities that they had guaranteed under contract. If such a delivery failure were to occur in one of our contracts, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties. In addition, in our businesses, we often extend credit to our counterparties. Despite performing credit analysis prior to extending credit, we are exposed to the risk that we might not be able to collect amounts owed to us. If the counterparty to such a transaction fails to perform and any collateral that secures our counterparty's obligation is inadequate, we will suffer a loss.

If we are unable to perform under our energy agreements, we could be required to pay damages. These damages generally would be based on the difference between the market price to acquire replacement energy or energy services and the relevant contract price. Depending on price volatility in the wholesale energy markets, such damages could be significant.

Risks Related to Regulations that Affect our Industry

Our natural gas sales, transmission, and storage operations are subject to government regulations and rate proceedings that could have an adverse impact on our results of operations.

Our interstate natural gas sales, transportation, and storage operations conducted through our Gas Pipelines business are subject to the FERC's rules and regulations in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. The FERC's regulatory authority extends to:

- transportation and sale for resale of natural gas in interstate commerce;
- rates and charges;
- construction;
- acquisition, extension or abandonment of services or facilities;
- accounts and records;
- depreciation and amortization policies;
- operating terms and conditions of service.

Regulatory actions in these areas can affect our business in many ways, including decreasing tariff rates and revenues, decreasing volumes in our pipelines, increasing our costs and otherwise altering the profitability of our business. Regulatory decisions could also affect our costs for compression, processing and dehydration of natural gas, which could have a negative effect on our results of operations.

The FERC has taken certain actions to strengthen market forces in the natural gas pipeline industry that have led to increased competition throughout the industry. In a number of key markets, interstate pipelines are now facing competitive pressure from other major pipeline systems, enabling local distribution companies and end users to choose a transportation provider based on considerations other than location.

Competition in the markets in which we operate may adversely affect our results of operations.

We have numerous competitors in all aspects of our businesses, and additional competitors may enter our markets. Other companies with which we compete may be able to respond more quickly to new laws or regulations or emerging technologies, or to devote greater resources to the construction, expansion or refurbishment of their facilities than we can. In addition, current or potential competitors may make strategic acquisitions or have greater financial resources than we do, which could affect our ability to make investments or acquisitions. There can be no assurance that we will be able to compete successfully against current and future competitors and any failure to do so could have a material adverse effect on our businesses and results of operations.

Expiration of firm transportation agreements.

A substantial portion of the operating revenues of our Gas Pipelines are generated through firm transportation agreements that expire periodically and must be renegotiated and extended or replaced. We cannot give any assurance as to whether any of these agreements will be extended or replaced or that the terms of any renegotiated agreements will be as favorable as the existing agreements. Upon the expiration of these agreements, should customers turn back or substantially reduce their commitments, we could experience a negative effect to our results of operations.

Our revenues might decrease if we are unable to gain adequate, reliable and affordable access to transportation and distribution assets.

We depend on transportation and distribution facilities owned and operated by utilities and other energy companies to deliver the commodities we buy and sell in the wholesale market. If transportation is disrupted, if capacity is inadequate, or if credit requirements or rates of such utilities or energy companies are increased, our ability to sell and deliver products might be hindered. Further, although there are laws and regulations designed to encourage competition in wholesale market transactions, some companies may fail to provide fair and equal access to their transportation systems or may not provide sufficient transportation capacity for other market participants.

Our businesses are subject to complex government regulations. The operation of our businesses might be adversely affected by changes in these regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Existing regulations might be revised or reinterpreted, new laws and regulations might be adopted or become applicable to us, our facilities or our customers, and future changes in laws and regulations might have a detrimental effect on our business. Over the past few years, certain restructured energy markets have experienced supply problems and price volatility. In some of these markets, proposals have been made by governmental agencies and other interested parties to re-regulate areas of these markets which have previously been deregulated. Various forms of market controls and limitations including price caps and bid caps have already been implemented and new controls and market restructuring proposals are in various stages of development, consideration and implementation. We cannot assure you that changes in market structure and regulation will not adversely affect our business and results of operations. We also cannot assure you that other proposals to re-regulate will not be made or that legislative or other attention to these restructured energy markets will not cause the deregulation process to be delayed or reversed or otherwise adversely affect our business and results of operations.

The outcome of a pending rate case to set the rates we can charge customers on Transco's pipeline might result in rates that do not provide an adequate return on the capital we have invested in the Transco pipeline.

We have a pending rate case with the FERC to request changes to the rates we charge on Transco. We have sought FERC approval of a settlement of the significant issues in the rate case but until FERC approves the settlement, the outcome of the rate case remains uncertain. There is a risk that rates set by the FERC will lower our return on the capital we have invested in our assets or might not be adequate to recover increases in operating costs. There is also the risk that higher rates will cause our customers to look for alternative ways to transport their natural gas.

Legal and regulatory proceedings and investigations relating to the energy industry and capital markets have adversely affected our business and may continue to do so.

Public and regulatory scrutiny of the energy industry and of the capital markets has resulted in increased regulation being either proposed or implemented. Such scrutiny has also resulted in various inquiries, investigations and court proceedings in which we are a named defendant. Both the shippers on our pipelines and regulators have rights to challenge the rates we charge under certain circumstances. Any successful challenge could materially affect our results of operations.

Certain inquiries, investigations and court proceedings are ongoing and continue to adversely affect our business as a whole. We might see these adverse effects continue as a result of the uncertainty of these ongoing inquiries and proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines or penalties, or other regulatory action, including legislation, which might be materially adverse to the operation of our business and our revenues and net income or increase our operating costs in other ways. Current legal proceedings or other matters against us arising out of our ongoing and discontinued operations including environmental matters, disputes over gas measurement, royalty payments, shareholder class action suits, regulatory appeals and similar matters might result in adverse decisions against us. The result of such adverse decisions, either individually or in the aggregate, could be material and may not be covered fully or at all by insurance.

Risks Related to Accounting Standards

Potential changes in accounting standards might cause us to revise our financial results and disclosures in the future, which might change the way analysts measure our business or financial performance.

Regulators and legislators continue to take a renewed look at accounting practices, financial disclosures, companies' relationships with their independent registered public accounting firms, and retirement plan practices. We cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies or the energy industry or in our operations specifically.

In addition, the Financial Accounting Standards Board (FASB) or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets, liabilities and equity.

Risks Related to Market Volatility and Risk Measurement and Hedging Activities

Our risk measurement and hedging activities might not be effective and could increase the volatility of our results.

Although we have systems in place that use various methodologies to quantify commodity price risk associated with our businesses, these systems might not always be followed or might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this report might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified.

In an effort to manage our financial exposure related to commodity price and market fluctuations, we have entered into contracts to hedge certain risks associated with our assets and operations. In these hedging activities, we have used fixed-price, forward, physical purchase and sales contracts, futures, financial swaps and option contracts traded in the over-the-counter markets or on exchanges. Nevertheless, no single hedging arrangement can adequately address all risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract's counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist. While we attempt to manage counterparty credit risk within guidelines established by our credit policy, we may not be able to successfully manage all credit risk and as such, future cash flows and results of operations could be impacted by counterparty default.

Our use of hedging arrangements through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," (SFAS 133) to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under SFAS 133, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to the Company has occurred during the applicable period.

The impact of changes in market prices for natural gas on the average gas prices received by us may be reduced based on the level of our hedging strategies. These hedging arrangements may limit our potential gains if the market prices for natural gas were to rise substantially over the price established by the hedge. In addition, our hedging arrangements expose us to the risk of financial loss in certain circumstances, including instances in which:

- production is less than expected;
- the hedging instrument is not perfectly effective in mitigating the risk being hedged;
- the counterparties to our hedging arrangements fail to honor their financial commitments.

Risks Related to Employees, Outsourcing of Non-Core Support Activities, and Technology

Institutional knowledge residing with current employees nearing retirement eligibility might not be adequately preserved.

In certain segments of our business, institutional knowledge resides with employees who have many years of service. As these employees reach retirement age, we may not be able to replace them with employees of comparable knowledge and experience. In addition, we may not be able to retain or recruit other qualified individuals and our efforts at knowledge transfer could be inadequate. If knowledge transfer, recruiting and retention efforts are inadequate, access to significant amounts of internal historical knowledge and expertise could become unavailable to us.

Failure of or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.

Some studies indicate a high failure rate of outsourcing relationships. Although we have taken steps to build a cooperative and mutually beneficial relationship with our outsourcing providers and to closely monitor their performance, a deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business.

Certain of our accounting, information technology, application development, and help desk services are currently provided by an outsourcing provider from service centers outside of the United States. The economic and political conditions in certain countries from which our outsourcing providers may provide services to us present similar risks of business operations located outside of the United States previously discussed, including risks of interruption of business, war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States.

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, 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.

Acts of terrorism could have a material adverse effect on our financial condition, results of operations and cash flows.

Our assets and the assets of our customers and others may be targets of terrorist activities that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to our ability to produce, process, transport or distribute natural gas, natural gas liquids or other commodities. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

We own property in 30 states plus the District of Columbia in the United States and in Argentina, Canada and Venezuela.

Gas Marketing’s primary assets are its term contracts, related systems and technological support. In our Gas Pipeline and Midstream segments, we generally own our facilities, although a substantial portion of our pipeline and gathering facilities is constructed and maintained pursuant to rights-of-way, easements, permits, licenses or consents on and across properties owned by others. In our Exploration & Production segment, the majority of our ownership interest in exploration and production properties is held as working interests in oil and gas leaseholds.

Item 3. ***Legal Proceedings***

The information called for by this item is provided in Note 15 of the Notes to Consolidated Financial Statements of this report, which information is incorporated by reference into this item.

Item 4. ***Submission of Matters to a Vote of Security Holders***

None.

Executive Officers of the Registrant

The name, age, period of service, and title of each of our executive officers as of February 21, 2008, are listed below.

Alan S. Armstrong	Senior Vice President, Midstream Age: 45 Position held since February 2002. From 1999 to February 2002, Mr. Armstrong was Vice President, Gathering and Processing for Midstream. From 1998 to 1999 he was Vice President, Commercial Development for Midstream. Mr. Armstrong serves as a director of Williams Partners GP LLC, the general partner of Williams Partners L.P.
James J. Bender	Senior Vice President and General Counsel Age 51 Position held since December 2002. Prior to joining us, Mr. Bender was Senior Vice President and General Counsel with NRG Energy, Inc., a position held since June 2000, prior to which he was Vice President, General Counsel and Secretary of NRG Energy Inc. since June 1997. NRG Energy, Inc. filed a voluntary bankruptcy petition during 2003 and its plan of reorganization was approved in December 2003.
Donald R. Chappel	Senior Vice President and Chief Financial Officer Age: 56 Position held since April 2003. Prior to joining us, Mr. Chappel during 2000 founded and served as chief executive officer of a development business in Chicago, Illinois through April 2003, when he joined us. Mr. Chappel joined Waste Management, Inc. in 1987 and held various financial, administrative and operational leadership positions, including twice serving as chief financial officer, during 1997 and 1998 and most recently during 1999 through February 2000. Mr. Chappel serves as a director of Williams Partners GP LLC, the general partner of Williams Partners L.P., and as a director of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P.

Ralph A. Hill	Senior Vice President, Exploration & Production Age: 48 Position held since December 1998. Mr. Hill was vice president of the exploration and production unit from 1993 to 1998 as well as Senior Vice President Petroleum Services from 1998 to 2003. Mr. Hill serves as a director of Apco Argentina Inc.
Michael P. Johnson, Sr.	Senior Vice President and Chief Administrative Officer Age: 60 Position held since May 2004. Mr. Johnson was named our Senior Vice President of Human Resources and Administration in April 1999. Prior to joining us in December 1998, he held officer level positions, such as Vice President of Human Resources, Vice President for Corporate People Strategies, and Vice President Human Resource Services, for Amoco Corporation from 1991 to 1998. Mr. Johnson serves as a director of Buffalo Wild Wings.
Steven J. Malcolm	Chairman of the Board, Chief Executive Officer and President Age: 59 Position held since September 2001. Mr. Malcolm was elected Chief Executive Officer of Williams in January 2002 and Chairman of the Board in May 2002. He was elected President and Chief Operating Officer in September 2001. Prior to that, he was our Executive Vice President from May 2001, President and Chief Executive Officer of our subsidiary Williams Energy Services, LLC, since December 1998 and the Senior Vice President and General Manager of our subsidiary, Williams Field Services Company, since November 1994. Mr. Malcolm serves as a director of Williams Partners GP LLC, the general partner of Williams Partners L.P., as a director of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P., and as a director of Bank of Oklahoma, N.A.
Phillip D. Wright	Senior Vice President, Gas Pipeline Age: 52 Position held since January 2005. From October 2002 to January 2005, Mr. Wright served as Chief Restructuring Officer. From September 2001 to October 2002, Mr. Wright served as President and Chief Executive Officer of our subsidiary Williams Energy Services. From 1996 until September 2001, he was Senior Vice President, Enterprise Development and Planning for our energy services group. Mr. Wright has held various positions with us since 1989. Mr. Wright serves as a director of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Our common stock is listed on the New York Stock Exchange under the symbol "WMB." At the close of business on February 21, 2008, we had approximately 11,153 holders of record of our common stock. The high and low closing sales price ranges (New York Stock Exchange composite transactions) and dividends declared by quarter for each of the past two years are as follows:

	2007			2006		
Quarter	High	Low	Dividend	High	Low	Dividend
1st	$ 28.94	$ 25.32	$ .09	$ 25.12	$ 19.49	$ .075
2nd	$ 32.43	$ 28.20	$ .10	$ 23.36	$ 20.33	$ .09
3rd	$ 34.72	$ 30.08	$ .10	$ 25.23	$ 22.51	$ .09
4th	$ 37.16	$ 33.68	$ .10	$ 27.95	$ 22.95	$ .09

Some of our subsidiaries' borrowing arrangements limit the transfer of funds to us. These terms have not impeded, nor are they expected to impede, our ability to pay dividends.

ISSUER PURCHASES OF EQUITY SECURITIES

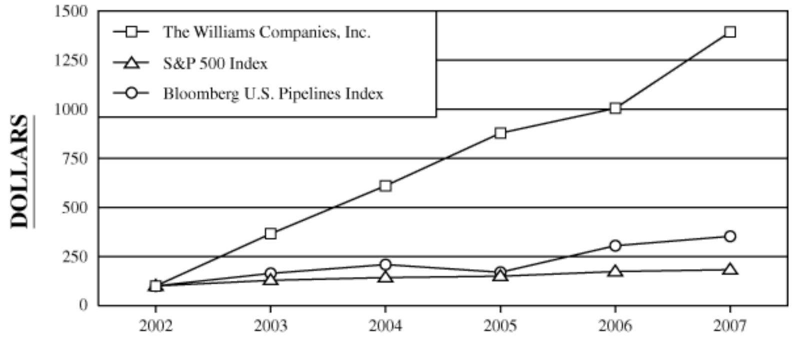
Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 — October 31, 2007	—	—	—	$ 766,140,266
November 1 — November 30, 2007	5,500,000	$ 34.54	5,500,000	$ 576,193,864
December 1 — December 31, 2007	2,946,200	$ 34.61	2,946,200	$ 474,228,219
Total	8,446,200	$ 34.56	8,446,200	$ 474,228,219

(1) We announced a stock repurchase program on July 20, 2007. Our board of directors has authorized the repurchase of up to $1 billion of the company's common stock. The stock repurchase program has no expiration date. We intend to purchase shares of our stock from time to time in open market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors.

Performance Graph

Set forth below is a line graph comparing our cumulative total stockholder return on our common stock (assuming reinvestment of dividends) with the cumulative total return of the S&P 500 Stock Index and the Bloomberg U.S. Pipeline Index for the period of five fiscal years commencing January 1, 2003. The Bloomberg U.S. Pipeline Index is composed of El Paso, Equitable Resources, Questar, Oneok, TransCanada, Spectra Energy, Enbridge and Williams. The graph below assumes an investment of $100 at the beginning of the period.

Cumulative Total Shareholder Return



	2002	2003	2004	2005	2006	2007
The Williams Companies, Inc.	100.0	365.7	610.2	878.3	1,004.5	1,393.1
S&P 500 Index	100.0	128.7	142.7	149.7	173.3	182.8
Bloomberg U.S. Pipelines Index	100.0	164.1	208.8	269.7	304.9	352.7

Item 6. ***Selected Financial Data***

The following financial data should be read in conjunction with Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations* and Part II, Item 8, *Financial Statements and Supplementary Data*.

	2007	2006	2005	2004	2003
		(Millions, except per-share amounts)			
Revenues(1)	$ 10,558	$ 9,376	$ 9,781	$ 8,408	$ 8,615
Income (loss) from continuing operations(2)	847	347	473	149	(248)
Income (loss) from discontinued operations(3)	143	(38)	(157)	15	517
Cumulative effect of change in accounting principles(4)	—	—	(2)	—	(761)
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	1.40	.57	.79	.28	(.54)
Income (loss) from discontinued operations	.23	(.06)	(.26)	.03	1.00
Cumulative effect of change in accounting principles	—	—	—	—	(1.47)
Total assets at December 31	25,061	25,402	29,443	23,993	27,022
Short-term notes payable and long-term debt due within one year at December 31	143	392	123	250	939
Long-term debt at December 31	7,757	7,622	7,591	7,712	11,040
Stockholders' equity at December 31	6,375	6,073	5,427	4,956	4,102
Cash dividends per common share	.39	.345	.25	.08	.04

(1) *Revenues* in 2003 includes approximately $117 million related to the correction of the accounting treatment previously applied to certain third-party derivative contracts during 2002 and 2001.

(2) See Note 4 of Notes to Consolidated Financial Statements for discussion of asset sales and other accruals in 2007, 2006, and 2005.

(3) See Note 2 of Notes to Consolidated Financial Statements for the analysis of the 2007, 2006 and 2005 income (loss) from discontinued operations. The discontinued operations results for 2004 and 2003 include the power business, the Canadian straddle plants, and the Alaska refining, retail, and pipeline operations. The 2003 discontinued operations results also include certain gas processing and natural gas liquid operations in Canada, a soda ash mining operation, a bio-energy operation, Texas Gas Transmission Corporation, certain natural gas production properties, our interest and investment in Williams Energy Partners, refining and marketing operations in the midsouth, and retail travel centers in the midsouth.

(4) The 2005 *cumulative effect of change in accounting principles* is due to implementation of Financial Accounting Standards Board (FASB) Interpretation No. 47 (FIN 47), "Accounting for Conditional Asset Retirement Obligations — an Interpretation of FASB statement No. 143 (SFAS 143)." The 2003 cumulative effect of change in accounting principles includes a $762 million charge related to the adoption of Emerging Issues Task Force Issue No. 02-3, slightly offset by $1 million related to the adoption of SFAS 143, "Accounting for Asset Retirement Obligations." The $762 million charge primarily consisted of the then fair value of power tolling, power load serving, gas transportation and gas storage contracts. The contracts were not derivatives and, therefore, were no longer reported at fair value.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

General

We are primarily a natural gas company, engaged in finding, producing, gathering, processing, and transporting natural gas. Our operations are located principally in the United States and are organized into the following reporting segments: Exploration & Production, Gas Pipeline, Midstream Gas & Liquids (Midstream), and Gas Marketing Services. (See Note 1 of Notes to Consolidated Financial Statements for further discussion of reporting segments.)

Unless indicated otherwise, the following discussion of critical accounting estimates, discussion and analysis of results of operations and financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto included in Part II Item 8 of this document.

Overview of 2007

Our plan for 2007 was focused on continued disciplined growth. Objectives and highlights of this plan included:

Objectives	Highlights
Continuing to improve both EVA® and segment profit.	2007 segment profit of almost $2.2 billion contributed to improving our EVA®.
Investing in our businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position.	Total capital expenditures were approximately $2.8 billion, of which approximately $1.7 billion was invested in Exploration & Production.
Continuing to increase natural gas production and reserves in a responsible and efficient manner.	Exploration & Production increased its average daily domestic production by approximately 21 percent over last year while adding 776 billion cubic feet equivalent in net reserves during 2007. Total year-end 2007 proved domestic natural gas reserves are 4.14 trillion cubic feet equivalent, up 12 percent from year-end 2006 reserves. Additionally, we received 2007 industry awards, including the Bureau of Land Management's Best Management Practice Award.
Increasing the scale of our gathering and processing business in key growth basins.	We invested approximately $587 million in capital expenditures in Midstream, including Deepwater Gulf expansion projects and completion of our Opal gas processing facility expansion.
Successfully resolving rate cases to enable our Gas Pipeline segment to create additional value.	Increased rates were effective, subject to refund, on January 1, 2007, for Northwest Pipeline and on March 1, 2007, for Transco. In March, the FERC approved Northwest Pipeline's new rates. In November, Transco filed a stipulation and settlement agreement with the FERC, which is subject to final approval.

Our 2007 *income from continuing operations* increased to $847 million, as compared to $347 million in 2006. Our *net cash provided by operating activities* was $2.2 billion in 2007 compared to $1.9 billion in 2006. These comparative results reflect:

- Increased operating income at Midstream due primarily to increased natural gas liquid (NGL) margins;

- Increased operating income at Exploration & Production associated with increased production volumes and higher net realized average prices;
- Increased operating income at Gas Pipeline due primarily to new rates effective in the first quarter of 2007;
- The absence of 2006 litigation expense associated with shareholder lawsuits and Gulf Liquids litigation.

Natural gas prices in the Rocky Mountain areas (Rockies) trended lower throughout 2007 due to strong drilling activities increasing third-party supplies while constrained by limited pipeline capacity. This trend has benefited Midstream as the lower regional gas prices contributed to increased NGL margins in the West region. Exploration & Production utilizes firm transportation contracts, which allow a substantial portion of their Rockies production to be sold at more advantageous market points, and basin-level collars and fixed-price hedges to reduce exposure to this trend.

See additional discussion in Results of Operations.

Recent Events

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. In February 2008, the underwriters also exercised their right to purchase an additional 1.65 million common units at the same price. A subsidiary of ours serves as the general partner of WMZ. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. Upon completion of the transaction, we hold approximately 47.7 percent of the interests in WMZ, including the interests of the general partner.

In December 2007, Williams Partners L.P. acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million. Williams Partners L.P. completed the transaction after successfully closing a public equity offering of 9.25 million common units that yielded net proceeds of approximately $335 million. The partnership financed the remainder of the purchase price primarily through utilizing $250 million of term loan borrowings and issuing approximately $157 million of common units to us. Since Williams Partners L.P. is consolidated within our consolidated financial statements, the debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. (See Note 1 of Notes to Consolidated Financial Statements.)

In December 2007, we repurchased $213 million of 7.125 percent notes due September 2011 and $22 million of 8.125 percent notes due March 2012. In conjunction with these early retirements, we paid premiums of approximately $19 million. These premiums, as well as related fees and expenses are recorded as *early debt retirement costs* in the Consolidated Statement of Income.

On November 9, 2007, we closed on the sale of substantially all of our power business to Bear Energy, LP, a unit of The Bear Stearns Companies, Inc., for $496 million, subject to post-closing adjustments. The assets sold included tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software. This sale reduces the risk and complexity of our overall business model.

In November 2007, our credit ratings were raised to investment grade based on improvements in our credit outlook. As we continue to invest and grow our natural gas businesses, our improved credit rating is expected to provide greater access to capital and more favorable loan terms. See additional discussion of credit ratings in *Management's Discussion and Analysis of Financial Condition*.

On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in Transco's pending 2006 rate case. Final resolution of the rate case is subject to approval by the FERC.

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open-market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. During 2007, we repurchased approximately 16 million shares for $526 million at an average cost of $33.08 per share. We are funding this program with cash on hand.

In April 2007, our Board of Directors approved a regular quarterly dividend of 10 cents per share, which reflected an increase of 11 percent compared to the 9 cents per share that we paid in each of the four prior quarters and marked the fourth increase in our dividend since late 2004.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline's system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

Outlook for 2008

Our plan for 2008 is focused on continued disciplined growth. Objectives of this plan include:

- Continue to improve both EVA® and segment profit.
- Invest in our businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position.
- Continue to increase natural gas production and reserves.
- Increase the scale of our gathering and processing business in key growth basins.

Potential risks and/or obstacles that could prevent us from achieving these objectives include:

- Volatility of commodity prices;
- Lower than expected levels of cash flow from operations;
- Decreased drilling success at Exploration & Production;
- Decreased drilling success by third parties served by Midstream and Gas Pipeline;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 15 of Notes to Consolidated Financial Statements);
- General economic and industry downturn.

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 our desired level of at least $1 billion in liquidity from cash and cash equivalents and unused revolving credit facilities.

New Accounting Standards and Emerging Issues

Accounting standards that have been issued and are not yet effective may have an effect on our Consolidated Financial Statements in the future. These include:

- SFAS No. 141(R) "Business Combinations" (SFAS No. 141(R)). SFAS No. 141(R) is effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008.
- SFAS No. 160 "Noncontrolling Interests in Consolidated Financial Statements — an amendment of Accounting Research Bulletin No. 51" (SFAS No. 160). SFAS No. 160 is effective for fiscal years beginning after December 15, 2008.

See *Recent Accounting Standards* in Note 1 of Notes to Consolidated Financial Statements for further information on these and other recently issued accounting standards.

Critical Accounting Estimates

The preparation of financial statements, in conformity with generally accepted accounting principles, requires management to make estimates and assumptions that affect the reported amounts therein. We have discussed the following accounting estimates and assumptions as well as related disclosures with our Audit Committee. We believe that the nature of these estimates and assumptions is material due to the subjectivity and judgment necessary, or the susceptibility of such matters to change, and the impact of these on our financial condition or results of operations.

Revenue Recognition — Derivative Instruments and Hedging Activities

We hold a portfolio of energy trading and nontrading contracts. We review these contracts to determine whether they are nonderivatives or derivatives. If they are derivatives, we further assess whether the contracts qualify for either cash flow hedge accounting or the normal purchases and normal sales exception.

The determination of whether a derivative contract qualifies as a cash flow hedge includes an analysis of historical market price information to assess whether the derivative is expected to be highly effective in achieving offsetting cash flows attributed to the hedged risk. We also assess whether the hedged forecasted transaction is probable of occurring. This assessment requires us to exercise judgment and consider a wide variety of factors in addition to our intent, including internal and external forecasts, historical experience, changing market and business conditions, our financial and operational ability to carry out the forecasted transaction, the length of time until the forecasted transaction is projected to occur, and the quantity of the forecasted transaction. In addition, we compare actual cash flows to those that were expected from the underlying risk. If a hedged forecasted transaction is not probable of occurring, or if the derivative contract is not expected to be highly effective, the derivative does not qualify for hedge accounting.

For derivatives that are designated as cash flow hedges, we do not reflect the effective portion of changes in their fair value in earnings until the associated hedged item affects earnings. For those that have not been designated as hedges or do not qualify for hedge accounting, we recognize the net change in their fair value in income currently (marked to market).

For derivatives that are designated as cash flow hedges, we prospectively discontinue hedge accounting and recognize future changes in fair value directly in earnings if we no longer expect the hedge to be highly effective, or if we believe that the hedged forecasted transaction is no longer probable of occurring. If the forecasted transaction becomes probable of not occurring, we reclass amounts previously recorded in other comprehensive income into earnings in addition to prospectively discontinuing hedge accounting. If the effectiveness of the derivative improves and is again expected to be highly effective in offsetting cash flows attributed to the hedged risk, or if the forecasted transaction again becomes probable, we may prospectively re-designate the derivative as a hedge of the underlying risk.

Derivatives for which the normal purchases and normal sales exception has been elected are accounted for on an accrual basis. In determining whether a derivative is eligible for this exception, we assess whether the contract provides for the purchase or sale of a commodity that will be physically delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In making this assessment, we consider numerous factors, including the quantities provided under the contract in relation to our business needs, delivery locations per the contract in relation to our operating locations, duration of time between entering the contract and delivery, past trends and expected future demand, and our past practices and customs with regard to such contracts. Additionally, we assess whether it is probable that the contract will result in physical delivery of the commodity and not net financial settlement.

The fair value of derivative contracts is determined based on the nature of the transaction and the market in which transactions are executed. We also incorporate assumptions and judgments about counterparty performance and credit considerations in our determination of their fair value. Contracts are executed in the following environments:

- Organized commodity exchange or over-the-counter markets with quoted prices;
- Organized commodity exchange or over-the-counter markets with quoted market prices but limited price transparency, requiring increased judgment to determine fair value;
- Markets without quoted market prices.

The number of transactions executed without quoted market prices is limited. We estimate the fair value of these contracts by using readily available price quotes in similar markets and other market analyses. The fair value of all derivative contracts is continually subject to change as the underlying commodity market changes and our assumptions and judgments change.

Additional discussion of the accounting for energy contracts at fair value is included in Energy Trading Activities within Item 7 and Note 1 of Notes to Consolidated Financial Statements.

Oil- and Gas-Producing Activities

We use the successful efforts method of accounting for our oil- and gas-producing activities. Estimated natural gas and oil reserves and forward market prices for oil and gas are a significant part of our financial calculations. Following are examples of how these estimates affect financial results:

- An increase (decrease) in estimated proved oil and gas reserves can reduce (increase) our unit-of-production depreciation, depletion and amortization rates.
- Changes in oil and gas reserves and forward market prices both impact projected future cash flows from our oil and gas properties. This, in turn, can impact our periodic impairment analyses, including that for goodwill.

The process of estimating natural gas and oil reserves is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering, and economic data. After being estimated internally, 99 percent of our reserve estimates are either audited or prepared by independent experts. (See Part I Item 1 for further discussion.) The data may change substantially over time as a result of numerous factors, including additional development activity, evolving production history, and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates could occur from time to time. A revision of our reserve estimates within reasonably likely parameters is not expected to result in an impairment of our oil and gas properties or goodwill. However, reserve estimate revisions would impact our depreciation and depletion expense prospectively. For example, a change of approximately 10 percent in oil and gas reserves for each basin would change our annual *depreciation, depletion and amortization* expense between approximately $33 million and $41 million. The actual impact would depend on the specific basins impacted and whether the change resulted from proved developed, proved undeveloped or a combination of these reserve categories.

Forward market prices, which are utilized in our impairment analyses, include estimates of prices for periods that extend beyond those with quoted market prices. This forward market price information is consistent with that generally used in evaluating our drilling decisions and acquisition plans. These market prices for future periods impact the production economics underlying oil and gas reserve estimates. The prices of natural gas and oil are volatile and change from period to period, thus impacting our estimates. An unfavorable change in the forward price curve within reasonably likely parameters is not expected to result in an impairment of our oil and gas properties or goodwill.

Contingent Liabilities

We record liabilities for estimated loss contingencies, including environmental matters, when we assess that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are generally reflected in income in the period in which new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Liabilities for contingent losses are based upon our assumptions and estimates and upon advice of legal counsel, engineers, or other third parties regarding the probable outcomes of the matter. As new developments occur or more information becomes available, our assumptions and estimates of these liabilities may change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarterly or annual period. See Note 15 of Notes to Consolidated Financial Statements.

Valuation of Deferred Tax Assets and Tax Contingencies

We have deferred tax assets resulting from certain investments and businesses that have a tax basis in excess of the book basis and from tax carry-forwards generated in the current and prior years. We must evaluate whether we will ultimately realize these tax benefits and establish a valuation allowance for those that may not be realizable. This evaluation considers tax planning strategies, including assumptions about the availability and character of future taxable income. At December 31, 2007, we have $717 million of deferred tax assets for which a $57 million valuation allowance has been established. When assessing the need for a valuation allowance, we considered forecasts of future company performance, the estimated impact of potential asset dispositions and our ability and intent to execute tax planning strategies to utilize tax carryovers. We do not expect to be able to utilize $57 million of foreign deferred tax assets primarily related to carryovers. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by potential changes in jurisdictional income tax laws and the circumstances surrounding the actual realization of related tax assets.

We regularly face challenges from domestic and foreign tax authorities regarding the amount of taxes due. These challenges include questions regarding the timing and amount of deductions and the allocation of income among various tax jurisdictions. Beginning January 1, 2007, we evaluate the liability associated with our various filing positions by applying the two step process of recognition and measurement as required by Financial Accounting Standards Board (FASB) Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" (FIN 48). The ultimate disposition of these contingencies could have a significant impact on net cash flows. To the extent we were to prevail in matters for which accruals have been established or were required to pay amounts in excess of our accrued liability, our effective tax rate in a given financial statement period may be materially impacted.

See Note 5 of Notes to Consolidated Financial Statements for additional information regarding FIN 48 and tax carryovers.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Net periodic benefit expense and obligations are impacted by various estimates and assumptions. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates, expected rate of compensation increase, health care cost trend rates, and employee demographics, including retirement age and mortality. These assumptions are reviewed annually and adjustments are made as needed. The assumptions utilized to compute expense and the benefit obligations are shown in Note 7 of Notes to Consolidated Financial Statements. The following table presents the estimated increase (decrease) in net periodic benefit expense and obligations resulting from a one-percentage-point change in the specified assumption.

	Benefit Expense		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Millions)			
Pension benefits:				
Discount rate	$ (6)	$ 11	$ (106)	$ 120
Expected long-term rate of return on plan assets	(11)	11	—	—
Rate of compensation increase	2	(2)	13	(13)
Other postretirement benefits:				
Discount rate	(4)	—	(37)	43
Expected long-term rate of return on plan assets	(2)	2	—	—
Assumed health care cost trend rate	5	(7)	55	(44)

The expected long-term rates of return on plan assets are determined by combining a review of historical returns realized within the portfolio, the investment strategy included in the plans' Investment Policy Statement, and capital market projections for the asset classifications in which the portfolio is invested as well as the target weightings of each asset classification. These rates are impacted by changes in general market conditions, but because they are long-term in nature, short-term market swings do not significantly impact the rates. Changes to our target asset allocation would also impact these rates. Our expected long-term rate of return on plan assets used for our pension plans is 7.75 percent for 2007. This rate was 7.75 percent in 2006 and 8.5 percent from 2002-2005. Over the past ten years, our actual average return on plan assets for our pension plans has been approximately 7.7 percent.

The discount rates are used to measure the benefit obligations of our pension and other postretirement benefit plans. The objective of the discount rates is to determine the amount, if invested at the December 31 measurement date in a portfolio of high-quality debt securities, that will provide the necessary cash flows when benefit payments are due. Increases in the discount rates decrease the obligation and, generally, decrease the related expense. The discount rates for our pension and other postretirement benefit plans were determined separately based on an approach specific to our plans and their respective expected benefit cash flows as described in Note 7 of Notes to Consolidated Financial Statements. Our discount rate assumptions are impacted by changes in general economic and market conditions that affect interest rates on long-term high-quality debt securities as well as the duration of our plans' liabilities.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes pension obligation and expense to increase.

The assumed health care cost trend rates are based on our actual historical cost rates that are adjusted for expected changes in the health care industry. An increase in this rate causes other postretirement benefit obligation and expense to increase.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2007. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2007 (Millions)	$ Change from 2006(1)	% Change from 2006(1)	2006 (Millions)	$ Change from 2005(1)	% Change from 2005(1)	2005 (Millions)
Revenues	$ 10,558	+1,182	+13%	$ 9,376	−405	−4%	$ 9,781
Costs and expenses:							
Costs and operating expenses	8,079	−513	−7%	7,566	+319	+4%	7,885
Selling, general and administrative expenses	471	−82	−21%	389	−112	−40%	277
Other (income) expense — net	(18)	+52	NM	34	+23	+40%	57
General corporate expenses	161	−29	−22%	132	+13	+9%	145
Securities litigation settlement and related costs	—	+167	+100%	167	−158	NM	9
Total costs and expenses	8,693			8,288			8,373
Operating income	1,865			1,088			1,408
Interest accrued — net	(653)	—	—	(653)	+7	+1%	(660)
Investing income	257	+89	+53%	168	+143	NM	25
Early debt retirement costs	(19)	+12	+39%	(31)	−31	NM	—
Minority interest in income of consolidated subsidiaries	(90)	−50	−125%	(40)	−14	−54%	(26)
Other income — net	11	−15	−58%	26	−1	−4%	27
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	1,371			558			774
Provision for income taxes	524	−313	−148%	211	+90	+30%	301
Income from continuing operations	847			347			473
Income (loss) from discontinued operations	143	+181	NM	(38)	+119	+76%	(157)
Income before cumulative effect of change in accounting principle	990			309			316
Cumulative effect of change in accounting principle	—	—	—	—	+2	+100%	(2)
Net income	$ 990			$ 309			$ 314

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

2007 vs. 2006

The increase in *revenues* is due primarily to higher Midstream revenues associated with increased natural gas liquid (NGL) and olefins marketing revenues and increased production of olefins and NGLs. Exploration & Production experienced higher revenues also due to increases in production volumes and net realized average prices. Additionally, Gas Pipeline revenues increased primarily due to increased rates in effect since the first quarter of 2007. These increases are partially offset by a mark-to-market loss recognized at Gas Marketing Services on a legacy derivative natural gas sales contract that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in December 2007.

The increase in *costs and operating expenses* is due primarily to increased NGL and olefins marketing purchases and increased costs associated with our olefins production business at Midstream. Additionally, Exploration & Production experienced higher depreciation, depletion and amortization and lease operating expenses due primarily to higher production volumes.

The increase in *selling, general and administrative expenses (SG&A)* is primarily due to increased staffing in support of increased drilling and operational activity at Exploration & Production, the absence of a $25 million gain in 2006 related to the sale of certain receivables at Gas Marketing Services, and a $9 million charge related to certain international receivables at Midstream.

Other (income) expense — net within *operating income* in 2007 includes:

- Income of $18 million associated with payments received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral;
- Income of $17 million associated with a change in estimate related to a regulatory liability at Northwest Pipeline;
- Income of $12 million related to a favorable litigation outcome at Midstream;
- Income of $8 million due to the reversal of a planned major maintenance accrual at Midstream;
- Expense of $20 million related to an accrual for litigation contingencies at Gas Marketing Services;
- Expense of $10 million related to an impairment of the Carbonate Trend pipeline at Midstream.

Other (income) expense — net within *operating income* in 2006 includes:

- A $73 million accrual for a Gulf Liquids litigation contingency;
- Income of $9 million due to a settlement of an international contract dispute at Midstream.

The increase in *general corporate expenses* is attributable to various factors, including higher employee-related costs, increased levels of charitable contributions and information technology expenses. The higher employee-related costs are primarily the result of higher stock compensation expense. (See Note 1 of Notes to Consolidated Financial Statements.)

The *securities litigation settlement and related costs* is primarily the result of our 2006 settlement related to class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000 and July 22, 2002. (See Note 15 of Notes to Consolidated Financial Statements.)

The increase in *operating income* reflects record high NGL margins at Midstream, continued strong natural gas production growth at Exploration & Production, the positive effect of new rates at Gas Pipeline, and the absence of 2006 litigation expenses associated with shareholder lawsuits and Gulf Liquids litigation.

Interest accrued — net includes a decrease of $19 million in interest expense associated with our Gulf Liquids litigation contingency, offset by changes in our debt portfolio, most significantly the issuance of new debt in December 2006 by Williams Partners L.P.

The increase in *investing income* is due to:

- An approximate $27 million increase in interest income primarily associated with larger cash and cash equivalent balances combined with slightly higher rates of return in 2007 compared to 2006;
- Increased equity earnings of $38 million due largely to increased earnings of our Gulfstream Natural Gas System, L.L.C. (Gulfstream), Discovery Producer Services LLC (Discovery) and Aux Sable Liquid Products, L.P. (Aux Sable) investments;
- The absence of a $16 million impairment in 2006 of a Venezuelan cost-based investment at Exploration & Production;
- Approximately $14 million of gains from sales of cost-based investments in 2007.

These increases are partially offset by the absence of an approximately $7 million gain on the sale of an international investment in 2006.

Early debt retirement costs in 2007 includes $19 million of premiums and fees related to the December 2007 repurchase of senior unsecured notes. (See Note 11 of Notes to Consolidated Financial Statements.) *Early debt retirement costs* in 2006 includes $27 million in premiums and fees related to the January 2006 debt conversion and $4 million of accelerated amortization of debt expenses related to the retirement of the debt secured by assets of Williams Production RMT Company.

Minority interest in income of consolidated subsidiaries increased primarily due to the growth in the minority interest holdings of Williams Partners L.P.

Provision for income taxes was significantly higher in 2007 due primarily to higher pre-tax earnings. The effective income tax rate for 2007 is slightly higher than the federal statutory rate primarily due to the effect of taxes on foreign operations and an accrual for income tax contingencies, partially offset by the utilization of charitable contribution carryovers not previously benefited. The effective income tax rate for 2006 is slightly higher than the federal statutory rate primarily due to state income taxes, the effect of taxes on foreign operations, nondeductible convertible debenture expenses and an accrual for income tax contingencies, partially offset by the favorable resolution of federal income tax litigation and the utilization of charitable contribution carryovers not previously benefited. The 2006 effective income tax rate has been increased by an adjustment to increase overall deferred income tax liabilities. (See Note 5 of Notes to Consolidated Financial Statements.)

Income (loss) from discontinued operations in 2007 primarily includes the operating results of substantially all of our power business and the sale of that business, which was completed in November 2007. (See Note 2 of Notes to Consolidated Financial Statements.) These results include the following pre-tax items:

- A $429 million gain associated with the reclassification of deferred net hedge gains from *accumulated other comprehensive income*, partially offset by unrealized mark-to-market losses of approximately $23 million;
- A $111 million impairment charge related to the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception under SFAS 133 and, accordingly, were no longer recording at fair value;
- A $37 million loss on the sale of substantially all of our power business;
- A $14 million impairment charge for our Hazelton power generation facility.

Income (loss) from discontinued operations in 2006 includes:

- A $14 million net-of-tax loss related to our discontinued power business (see Note 2 of Notes to Consolidated Financial Statements);
- A $12 million net-of-tax litigation settlement related to our former chemical fertilizer business;
- A $4 million net-of-tax charge associated with the settlement of a loss contingency related to a former exploration business;
- A $9 million net-of-tax charge associated with an oil purchase contract related to our former Alaska refinery.

2006 vs. 2005

The decrease in *revenues* is primarily due to lower natural gas realized revenues at Gas Marketing Services associated with lower natural gas sales prices. Additionally, the effect of a change in forward prices on legacy natural gas derivative contracts not designated as cash flow hedges had an unfavorable impact on revenues. Partially offsetting these decreases are increased crude, olefin and NGL marketing revenues, higher NGL production revenue at Midstream and increased production revenue at Exploration & Production.

The decrease in *costs and operating expenses* is largely due to reduced natural gas purchase prices at Gas Marketing Services. Partially offsetting these decreases are increased crude, olefin and NGL marketing purchases and operating expenses at Midstream and increased depreciation, depletion and amortization and lease operating expense at Exploration & Production.

The increase in *SG&A expenses* is primarily due to increased personnel costs, insurance expense, higher information systems support costs and the absence of a $17 million reduction of pension expense at Gas Pipeline in 2005. Additionally, Exploration & Production experienced higher costs due to increased staffing in support of increased drilling and operational activity.

Other (income) expense — net within *operating income* in 2005 includes:

- An $82 million accrual for litigation contingencies at Gas Marketing Services, associated primarily with agreements reached to substantially resolve exposure related to certain natural gas price and volume reporting issues;
- Gains totaling $30 million on the sale of certain natural gas properties at Exploration & Production;
- A gain of $9 million on a sale of land in our Other segment.

General corporate expenses decreased primarily due to the absence of $14 million of insurance settlement charges in 2005 associated with certain insurance coverage allocation issues.

The decrease in *operating income* primarily reflects the negative effect of a change in forward prices on natural gas derivative contracts at Gas Marketing Services, higher operating and administrative costs at Gas Pipeline and 2006 litigation expenses associated with shareholder lawsuits and Gulf Liquids litigation. These decreases are partially offset by higher margins at Midstream and the absence a 2005 accrual for estimated litigation contingencies associated primarily with agreements reached to substantially resolve exposure related to natural gas price and volume reporting issues.

Interest accrued — net in 2006 includes $22 million in interest expense associated with our Gulf Liquids litigation contingency.

The increase in *investing income* is due to:

- The absence of an $87 million impairment in 2005 on our investment in Longhorn Partners Pipeline, L.P. (Longhorn);
- The absence of a $23 million impairment in 2005 of our Aux Sable equity investment;
- An approximate $30 million increase in interest income primarily associated with increased earnings on cash and cash equivalent balances associated with higher rates of return;
- Increased equity earnings of $33 million due largely to the absence of equity losses in 2006 on Longhorn and increased earnings of our Discovery and Aux Sable investments.

These increases are partially offset by:

- A $16 million impairment of a Venezuelan cost-based investment at Exploration & Production in 2006;
- The absence of a $9 million gain on sale of our remaining Mid-America Pipeline (MAPL) and Seminole Pipeline (Seminole) investments at Midstream in 2005.

The increase in *minority interest in income of consolidated subsidiaries* is primarily due to the growth of Williams Partners L.P.

Provision for income taxes was significantly lower in 2006 due primarily to lower pre-tax earnings. The effective income tax rate for 2006 is slightly higher than the federal statutory rate primarily due to state income taxes, the effect of taxes on foreign operations, nondeductible convertible debenture expenses and an accrual for income tax contingencies, partially offset by the favorable resolution of federal income tax litigation and the utilization of charitable contribution carryovers not previously benefited. The 2006 effective income tax rate has been increased by an adjustment to increase overall deferred income tax liabilities. The effective income tax rate for 2005 is higher than the federal statutory rate due primarily to state income taxes, nondeductible expenses and the inability to utilize charitable contribution carryovers. The 2005 effective income tax rate was reduced by an adjustment to reduce overall deferred income tax liabilities and favorable settlements on federal and state income tax matters. (See Note 5 of Notes to Consolidated Financial Statements.)

Income (loss) from discontinued operations in 2005 includes a $155 million net-of-tax loss related to our discontinued power business. (See Note 2 of Notes to Consolidated Financial Statements.)

Cumulative effect of change in accounting principle in 2005 is due to the implementation of FIN 47.

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Results of Operations — Segments

We are currently organized into the following segments: Exploration & Production, Gas Pipeline, Midstream, Gas Marketing Services, and Other. Other primarily consists of corporate operations. Our management currently evaluates performance based on segment profit (loss) from operations. (See Note 17 of Notes to Consolidated Financial Statements.)

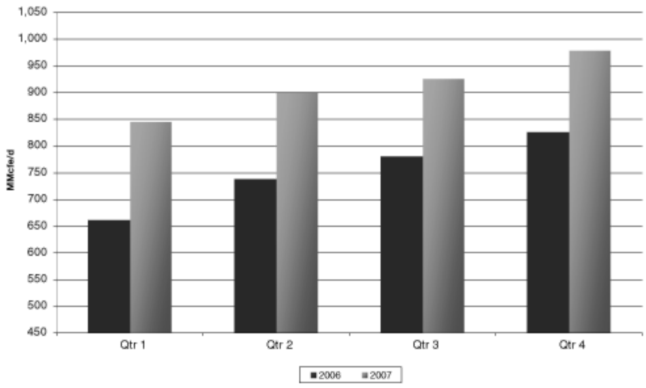
Exploration & Production

Overview of 2007

In 2007, we continued our strategy of a rapid execution of our development drilling program in our growth basins. Accordingly, we:

- Increased average daily domestic production levels by approximately 21 percent compared to last year. The average daily domestic production was approximately 913 million cubic feet of gas equivalent (MMcfe) in 2007 compared to 752 MMcfe in 2006. The increased production is primarily due to increased development within the Piceance, Powder River, and Fort Worth basins.

2007 vs 2006 Domestic Production



Average daily domestic production grew 21 percent or 161 MMcfe per day

- Benefited from increased domestic net realized average prices, which increased by approximately 15 percent compared to last year. The domestic net realized average price was $5.08 per thousand cubic feet of gas equivalent (Mcfe) in 2007 compared to $4.40 per Mcfe in 2006. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.
- Utilized firm transportation contracts which allowed a substantial portion of our Rockies production to be sold at more advantageous market points outside of the Rocky Mountain markets. Basin-level collars and fixed-price hedges also reduced our exposure to natural gas prices in the Rockies.
- Continued our aggressive development drilling program, drilling 1,590 gross wells in 2007 with a success rate of over 99 percent. This contributed to total net additions of 776 billion cubic feet equivalent (Bcfe) in net reserves — a replacement rate for our domestic production of 232 percent in 2007 compared to 216 percent in 2006. Capital expenditures for domestic drilling, development, and acquisition activity in 2007 were approximately $1.7 billion compared to approximately $1.4 billion in 2006.

The benefits of higher production volumes and higher net realized average prices were partially offset by increased operating costs. The increase in operating costs was primarily due to increased production volumes and higher well service and industry costs. In addition, higher production volumes increased depletion, depreciation and amortization expense.

Significant events

In February 2007, we entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Margin requirements, if any, under this new facility are dependent on the level of hedging and on natural gas reserves value. (See Note 11 of Notes to Consolidated Financial Statements.) We may also execute hedges with the Gas Marketing Services segment, which, in turn, executes offsetting derivative contracts with unrelated third parties. In this situation, Gas Marketing Services, generally, bears the counterparty performance risks associated with unrelated third parties. Hedging decisions primarily are made considering our overall commodity risk exposure and are not executed independently by Exploration & Production.

In May and July 2007, we increased our position in the Fort Worth basin by acquiring producing properties and leasehold acreage for approximately $41 million. These acquisitions are consistent with our growth strategy of leveraging our horizontal drilling expertise by acquiring and developing low-risk properties in the Barnett Shale formation. In July 2007, we increased our position in the Piceance basin by acquiring additional undeveloped leasehold acreage for approximately $36 million.

Outlook for 2008

Our expectations and objectives for 2008 include:

- Maintaining our development drilling program in our key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth through our planned capital expenditures projected between $1.45 billion and $1.65 billion.

- Continuing to grow our average daily domestic production level with a goal of approximately 10 to 15 percent annual growth.

Natural gas prices in the Rocky Mountain areas trended lower throughout 2007 due to strong drilling activities increasing supplies while constrained by limited pipeline capacity. However, we will continue to utilize firm transportation contracts which allow a substantial portion of our Rockies production to be sold at more advantageous market points. Our continued use of basin-level collars and fixed-price hedges should also reduce our exposure to this trend. The construction of a new third-party pipeline that began transporting gas from the Rocky Mountain areas in the beginning of 2008 should lessen pipeline transportation capacity constraints and provided an additional alternative market for the sale of production.

Approximately 70 MMcf of our forecasted 2008 daily domestic production is hedged by NYMEX and basis fixed-price contracts at prices that average $3.97 per Mcf at a basin level. In addition, we have the following collar agreements for our forecasted 2008 daily domestic production, shown at basin-level weighted-average prices and weighted-average volumes:

	Volume (MMcf/d)	Floor Price ($/Mcf)	Ceiling Price ($/Mcf)
2008 collar agreements:			
Northwest Pipeline/Rockies	170	$ 6.16	$ 9.14
El Paso/San Juan	202	$ 6.35	$ 8.96
Mid-Continent (PEPL)	25	$ 6.91	$ 9.13

Risks to achieving our expectations include unfavorable natural gas market price movements which are impacted by numerous factors including weather conditions and domestic natural gas production and consumption. Also, achievement of expectations can be affected by costs of services associated with drilling.

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We will recognize a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Segment revenues	$ 2,093	$ 1,488	$ 1,269
Segment profit	$ 756	$ 552	$ 587

2007 vs. 2006

Total *segment revenues* increased $605 million, or 41 percent, primarily due to the following:

- $487 million, or 39 percent, increase in domestic production revenues reflecting $264 million associated with a 21 percent increase in production volumes sold and $223 million associated with a 15 percent increase in net realized average prices. The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance and Powder River basins. The impact of hedge positions on increased net realized average prices includes both the expiration of a portion of fixed-price hedges that are lower than the current market prices and higher than current market prices related to basin-specific collars entered into during the period. Production revenues in 2007 include approximately $53 million related to natural gas liquids. In 2006, approximately $29 million of similar revenues were classified within other revenues;
- $139 million increase in revenues for gas management activities related to gas sold on behalf of certain outside parties which is offset by a similar increase in *segment costs and expenses*;

These increases were partially offset by a $30 million decrease relating to hedge ineffectiveness. In 2006, there were $14 million in net unrealized gains from hedge ineffectiveness as compared to $16 million in net unrealized losses in 2007.

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. Approximately 19 percent of domestic production in 2007 was hedged by NYMEX and basis fixed-price contracts at a weighted-average price of $3.90 per Mcf at a basin level compared to 40 percent hedged at a weighted-average price of $3.82 per Mcf for 2006. Also, approximately 30 percent and 15 percent of 2007 and 2006 domestic production was hedged in the following collar agreements shown at basin-level weighted-average prices and weighted-average volumes:

	Volume (MMcf/d)	Floor Price ($/Mcf)	Ceiling Price
2007 collar agreements:			
NYMEX	15	$ 6.50	$ 8.25
Northwest Pipeline/Rockies	50	$ 5.65	$ 7.45
El Paso/San Juan	130	$ 5.98	$ 9.63
Mid-Continent (PEPL)	76	$ 6.82	$ 10.77
2006 collar agreements:			
NYMEX	49	$ 6.50	$ 8.25
NYMEX	15	$ 7.00	$ 9.00
Northwest Pipeline/Rockies	50	$ 6.05	$ 7.90

Total *segment costs and expenses* increased $404 million, primarily due to the following:

- $173 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;
- $139 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment revenues*;
- $46 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins in combination with higher well service expenses, facility expenses, equipment rentals, maintenance and repair services, and salt water disposal expenses;
- $36 million higher *SG&A expenses* primarily due to increased staffing in support of increased drilling and operational activity, including higher compensation. In addition, we incurred higher insurance and information technology support costs related to the increased activity. First quarter 2007 also includes approximately $5 million of expenses associated with a correction of costs incorrectly capitalized in prior periods.

The $204 million increase in s*egment profit* is primarily due to the 21 percent increase in domestic production volumes sold as well as the 15 percent increase in net realized average prices, partially offset by the increase in *segment costs and expenses*.

2006 vs. 2005

Total *segment revenues* increased $219 million, or 17 percent, primarily due to the following:

- $165 million, or 15 percent, increase in domestic production revenues reflecting $245 million primarily associated with a 23 percent increase in natural gas production volumes sold, offset by a decrease of $80 million associated with a 6 percent decrease in net realized average prices. The increase in production volumes is primarily from the Piceance and Powder River basins and the decrease in prices reflects the downward trending of market prices in the latter part of 2006.
- $10 million increase in production revenues from our international operations primarily due to increases in net realized average prices for crude oil production volumes sold.
- $14 million of net unrealized gains in 2006 from hedge ineffectiveness and forward mark-to-market gains on certain basis swaps not designated as hedges as compared to $10 million in net unrealized losses attributable to hedge ineffectiveness from NYMEX collars in 2005.

In 2005, approximately 47 percent of domestic production was hedged by NYMEX and basis fixed-price contracts at a weighted-average price of $3.99 per Mcf. Approximately 10 percent of domestic production was hedged by a NYMEX collar agreement for approximately 50 MMcf per day at a floor price of $7.50 per Mcf and a ceiling price of $10.49 per Mcf in the first quarter and at a floor price of $6.75 per Mcf and a ceiling price of $8.50 per Mcf in the second, third, and fourth quarters, and a Northwest Pipeline/Rockies collar agreement for approximately 50 MMcf per day in the fourth quarter at a floor price of $6.10 per Mcf and a ceiling price of $7.70 per Mcf.

Total *segment costs and expenses* increased $257 million, primarily due to the following:

- $107 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;
- $54 million higher lease operating expense primarily due to the increased number of producing wells and higher well service and industry costs due to increased demand and approximately $6 million for out-of-period expenses related to 2005;
- $33 million higher selling, general and administrative expenses primarily due to higher compensation for additional staffing in support of increased drilling and operational activity. In addition, we incurred higher legal, insurance, and information technology support costs related to the increased activity;
- $19 million higher operating taxes primarily due to higher production volumes sold and increased tax rates;
- The absence in 2006 of $30 million of gains on the sales of properties in 2005.

The $35 million decrease in *segment profit* is primarily due to lower net realized average prices and higher *segment costs and expenses* as discussed previously, and the absence in 2006 of $30 million of gains on the sales of properties in 2005. Partially offsetting these decreases are a 23 percent increase in domestic production volumes sold and increase in income from ineffectiveness and forward mark-to-market gains. *Segment profit* also includes an $8 million increase in our international operations primarily due to higher revenue and equity earnings as a result of increases in net realized average prices for crude oil production volumes sold.

Gas Pipeline

Overview

Our strategy to create value for our shareholders focuses on maximizing the utilization of our pipeline capacity by providing high quality, low cost transportation of natural gas to large and growing markets.

Gas Pipeline's interstate transmission and storage activities are subject to regulation by the FERC and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, expansion or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established through the FERC's ratemaking process. Changes in commodity prices and volumes transported have little impact on revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

Significant events of 2007 include:

Gas Pipeline master limited partnership

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. In February 2008, the underwriters also exercised their right to purchase an additional 1.65 million common units at the same price. A subsidiary of ours serves as the general partner of WMZ. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. Upon completion of the transaction, we hold approximately 47.7 percent of the interests in WMZ, including the interests of the general partner.

Status of rate cases

During 2006, Northwest Pipeline and Transco each filed general rate cases with the FERC for increases in rates. The new rates were effective, subject to refund, on January 1, 2007, for Northwest Pipeline and on March 1, 2007, for Transco.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline's system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in Transco's pending 2006 rate case. Final resolution of the rate case is subject to approval by the FERC.

Parachute Lateral project

In May 2007, we placed into service a 37.6-mile expansion of 30-inch diameter line in northwest Colorado. The expansion increased capacity by 450 Mdt/d at a cost of approximately $86 million. In December 2007, this asset was purchased by Midstream. In an arrangement approved by the FERC, Midstream will lease the pipeline to Gas Pipeline, who will continue to operate the pipeline until completion of a planned FERC abandonment filing.

Leidy to Long Island expansion project

In December 2007, we placed into service an expansion of certain existing pipeline facilities in the northeast United States. The project increased firm transportation capacity by 100 Mdt/d at an approximate cost of $169 million.

Potomac expansion project

In November 2007, we placed into service 16.5 miles of 42-inch pipeline in the Mid-Atlantic region of the United States. The second phase of the project involving installation of certain facilities will be completed in the fall of 2008. The project provides 165 Mdt/d of incremental firm capacity at an approximate total cost of $88 million.

Outlook for 2008

Gulfstream

In June 2007, our equity method investee, Gulfstream, received FERC approval to extend its existing pipeline approximately 34 miles within Florida. The extension will fully subscribe the remaining 345 Mdt/d of firm capacity on the existing pipeline. Construction began in January 2008. The estimated cost of this project is approximately $130 million and is expected to be placed into service in July 2008.

In September 2007, Gulfstream received FERC approval to construct 17.5 miles of 20-inch pipeline and to install a new compressor facility. Construction began in December 2007. The pipeline expansion will increase capacity by 155 Mdt/d and is expected to be placed into service in September 2008. The compressor facility is expected to be placed into service in January 2009. The estimated cost of this project is approximately $153 million.

Sentinel expansion project

In December 2007, we filed an application with the FERC to construct an expansion in the northeast United States. The estimated cost of the project is approximately $169 million. The expansion will increase capacity by 142 Mdt/d and is expected to be placed into service in two phases, occurring in November 2008 and November 2009.

Jackson Prairie expansion project

We own a one-third interest in the Jackson Prairie underground storage facility located in Washington, with the remaining interests owned by two of our distribution customers. In February 2007, we received FERC approval to expand the Jackson Prairie facility. The expansion will increase our one-third share of the capacity by 104 Mdt/d and is expected to be placed into service in November 2008.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Segment revenues	$1,610	$1,348	$1,413
Segment profit	$ 673	$ 467	$ 586

2007 vs. 2006

Revenues increased $262 million, or 19 percent, due primarily to a $173 million increase in transportation revenue and a $25 million increase in storage revenue resulting primarily from new rates effective in the first quarter of 2007. In addition, revenues increased $59 million due to the sale of excess inventory gas.

Costs and operating expenses increased $86 million, or 11 percent, due primarily to:

- An increase of $59 million associated with the sale of excess inventory gas, which includes a $19 million deferred gain, half of which will be payable to customers, pending FERC approval;
- An increase in depreciation expense of $30 million due to property additions;
- An increase in personnel costs of $10 million due primarily to higher compensation as well as an increase in number of employees;
- The absence of a $3 million credit to expense recorded in 2006 related to corrections of the carrying value of certain liabilities.

Partially offsetting these increases is a decrease of $12 million in contract and outside service costs and a decrease of $7 million in materials and supplies expense.

Other (income) expense — net changed favorably by $15 million due primarily to $18 million of income associated with payments received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral. Also included in the favorable change is $17 million of income recorded in the second quarter of 2007 for a change in estimate related to a regulatory liability at Northwest Pipeline, partially offset by $18 million of expense related to higher asset retirement obligations.

Equity earnings increased $14 million due primarily to a $14 million increase in equity earnings from Gulfstream. Gulfstream's higher earnings were primarily due to a decrease in property taxes from a favorable litigation outcome as well as improved operating results.

The $206 million, or 44 percent, increase in *segment profit* is due primarily to $262 million higher revenues, $14 million higher equity earnings and $15 million favorable *other (income) expense — net* as previously discussed. Partially offsetting these increases are higher *costs and operating expenses* as previously discussed.

2006 vs. 2005

Significant 2005 adjustments

Operating results for 2005 included:

- Adjustments of $18 million reflected as a $12 million reduction of *costs and operating expenses* and a $6 million reduction of *SG&A expenses*. These cost reductions were corrections of the carrying value of certain liabilities that were recorded in prior periods. Based on a review by management, these liabilities were no longer required.
- Pension expense reduction of $17 million in the second quarter of 2005 to reflect the cumulative impact of a correction of an error attributable to 2003 and 2004. The error was associated with the actuarial

computation of annual net periodic pension expense and resulted from the identification of errors in certain Transco participant data involving annuity contract information utilized for 2003 and 2004.

- Adjustments of $37 million reflected as increases in *costs and operating expenses* related to $32 million of prior period accounting and valuation corrections for certain inventory items and an accrual of $5 million for contingent refund obligations.

Revenues decreased $65 million, or 5 percent, due primarily to $75 million lower revenues associated with exchange imbalance settlements (offset in *costs and operating expenses*). Partially offsetting this decrease is a $9 million increase in revenue due to an adjustment for the recovery of state income tax rate changes (offset in *provision for income taxes*).

Costs and operating expenses decreased $17 million, or 2 percent, due primarily to:

- A decrease in costs of $75 million associated with exchange imbalance settlements (offset in *revenues*);
- A decrease in costs of $37 million related to the absence of $32 million of 2005 prior period accounting and valuation corrections for certain inventory items and an accrual of $5 million for contingent refund obligations.

Partially offsetting these decreases are:

- An increase in contract and outside service costs of $23 million due primarily to higher pipeline assessment and repair costs;
- An increase in depreciation expense of $15 million due to property additions;
- An increase in operating and maintenance expenses of $15 million;
- An increase in operating taxes of $10 million;
- The absence of $14 million of income in 2005 associated with the resolution of litigation;
- The absence of $12 million of expense reductions during 2005 related to the carrying value of certain liabilities.

SG&A expenses increased $77 million, or 92 percent, due primarily to:

- An increase in personnel costs of $18 million;
- The absence of a 2005 $17 million reduction in pension costs to correct an error in prior periods;
- An increase in information systems support costs of $16 million;
- An increase in property insurance expenses of $14 million;
- The absence of $6 million of cost reductions in 2005 that related to correcting the carrying value of certain liabilities.

The $119 million, or 20 percent, decrease in *segment profit* is due primarily to the absence of significant 2005 adjustments as previously discussed, increases in *costs and operating expenses* and *SG&A expenses* as previously discussed, and the absence of a $5 million construction completion fee recognized in 2005 related to our investment in Gulfstream.

Midstream Gas & Liquids

Overview of 2007

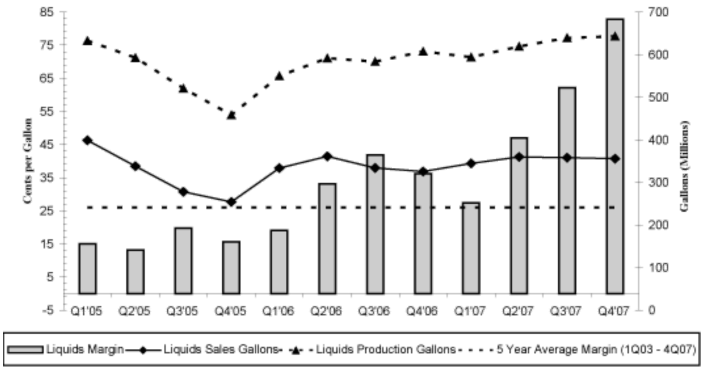
Midstream's ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. Our business is focused on consistently attracting new business by providing highly reliable service to our customers.

Significant events during 2007 include the following:

Continued favorable commodity price margins

The average realized natural gas liquid (NGL) per unit margins at our processing plants during 2007 was a record high 55 cents per gallon. NGL margins exceeded Midstream's rolling five-year average for the last seven quarters. The geographic diversification of Midstream assets contributed significantly to our realized unit margins resulting in margins generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and fractionated and sold at Mont Belvieu. The largest impact was realized at our western United States gas processing plants, which benefited from lower regional market natural gas prices.

Domestic Gathering and Processing Per Unit NGL Margin with Production and Sales Volumes by Quarter (excludes partially owned plants)



Expansion efforts in growth areas

Consistent with our strategy, we continued to expand our midstream operations where we have large-scale assets in growth basins.

During the first quarter of 2007, we completed construction at our existing gas processing complex located near Opal, Wyoming, to add a fifth cryogenic gas processing train capable of processing up to 350 MMcf/d, bringing total Opal capacity to approximately 1,450 MMcf/d. This plant expansion became operational during the first quarter. We also have several expansion projects ongoing in the West region to lower field pressures and increase production volumes for our customers who continue robust drilling activities in the region.

We continue construction of 37-mile extensions of both of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. These extensions, estimated to cost approximately $250 million, are expected to be ready for service by the second quarter of 2008.

During 2007, we have continued construction activities on the Perdido Norte project which includes oil and gas lines that would expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. In addition, we completed agreements with certain producers to provide gathering, processing and transportation services over the life of the reserves. We also intend to expand our Markham gas processing facility to adequately serve this new gas production. The scale of the project has increased to include additional pipeline and more efficient processing capacity. The estimated cost is now approximately $560 million, and it is expected to be in service in the third quarter of 2009.

In July 2007, we exercised our right of first refusal to acquire BASF's 5/12th ownership interest in the Geismar olefins facility for approximately $62 million. The acquisition increases our total ownership to 10/12th.

In March 2007, we announced plans to construct and operate the new Willow Creek facility, a 450 MMcf/d natural gas processing plant in western Colorado's Piceance basin, where Exploration & Production has its most significant volume of natural gas production, reserves and development activity. Exploration & Production's existing Piceance basin processing plants are primarily designed to condition the natural gas to meet quality specifications for pipeline transmission, not to maximize the extraction of NGLs. We expect the new Willow Creek facility to recover 25,000 barrels per day of NGLs at startup, which is expected to be in the third quarter of 2009.

In December 2007, we purchased the Parachute Lateral system from Gas Pipeline. The system is a 37.6-mile expansion, originally placed in service by Gas Pipeline in May 2007, and provides capacity of 450 Mdt/d through a 30-inch diameter line, transporting residue gas from the Piceance basin to the Greasewood Hub in northwest Colorado. The Willow Creek facility will straddle the Parachute Lateral pipeline and will process gas flowing through the pipeline. In an arrangement approved by the FERC, Midstream will lease the pipeline to Gas Pipeline, who will continue to operate the pipeline until completion of a planned FERC abandonment filing.

In addition, we have acquired an existing natural gas pipeline from Gas Pipeline, and begun the process of converting it from natural gas to NGL service and constructing additional pipeline to create a pipeline alternative for NGLs currently being transported by truck from Exploration & Production's existing Piceance basin processing plants to a major NGL transportation pipeline system.

We have also agreed to dedicate our equity NGL volumes from Willow Creek, along with our two Wyoming plants, for transport under a long-term shipping agreement with Overland Pass Pipeline Company, LLC. We currently have a 1 percent interest in Overland Pass Pipeline Company, LLC and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational. Start-up is planned for mid-2008. The terms of the shipping agreement represent significant savings compared with agreements we are now utilizing.

Williams Partners L.P.

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. Considering the control of the general partner in accordance with EITF Issue No. 04-5, Williams Partners L.P. is consolidated within the Midstream segment. (See Note 1 of Notes to Consolidated Financial Statements.) Midstream's segment profit includes 100 percent of Williams Partners L.P.'s segment profit, with the minority interest's share deducted below segment profit. The debt and equity issued by Williams Partners L.P. to third parties is reported as a component of our consolidated debt balance and minority interest balance, respectively.

In June 2007, Williams Partners L.P. completed its acquisition of our 20 percent interest in Discovery Producer Services, LLC (Discovery). Williams Partners L.P. now owns a 60 percent interest in Discovery.

In December 2007, Williams Partners L.P. acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million. Williams Partners L.P. completed the transaction after successfully closing a public equity offering of 9.25 million common units that yielded net proceeds of approximately $335 million. The partnership primarily financed the remainder of the purchase price through utilizing $250 million of term loan borrowings and issuing approximately $157 million of common units to us. The $250 million term loan is under Williams Partners L.P.'s new $450 million five-year senior unsecured credit facility that became effective simultaneously with the closing of the Wamsutter transaction. (See Note 11 of Notes to Consolidated Financial Statements.)

Ignacio Gas Processing Plant Fire

On November 28, 2007, there was a fire at the Ignacio gas processing plant. This fire resulted in severe damage to the facility's cooling tower, control room, adjacent warehouse buildings and control systems. The plant was shut down until January 18, 2008. There were no injuries as a result of this incident and the plant now has full cryogenic recovery capability available for operation. The impact of the fire was immaterial to our results of operations.

Outlook for 2008

The following factors could impact our business in 2008 and beyond.

- As evidenced in recent years, natural gas and crude oil markets are highly volatile. NGL margins earned at our gas processing plants in the last seven quarters were above our rolling five-year average, due to global economics maintaining high crude prices which correlate to strong NGL prices in relationship to natural gas prices. Forecasted domestic demand for ethylene and propylene, along with political instability in many of the key oil producing countries, currently support NGL margins continuing to exceed our rolling five-year average. Natural gas prices in the Rocky Mountain areas have trended lower throughout 2007 due to strong drilling activities increasing supplies while third-party production volumes have been constrained by limited pipeline capacity. The construction of a new third-party pipeline that began transporting gas from the Rocky Mountain areas in the beginning of 2008 would indicate increasing natural gas prices, moderating our future NGL margins.
- If the previously mentioned Overland Pass pipeline is not completed as scheduled, our NGL transportation costs will increase in the short-term over 2007 levels. When the pipeline is complete, the terms of our transportation agreement represent significant savings compared to 2007.
- As part of our efforts to manage commodity price risks on an enterprise basis, during December 2007 and January and February 2008, we entered into various financial contracts. Approximately 28 percent of our forecasted domestic NGL sales for 2008 are hedged with collar agreements or fixed-price swap contracts. Approximately 24 percent of our forecasted domestic NGL sales have been hedged with collar agreements at a weighted average sales price range of 9 percent to 22 percent above our average 2007 domestic NGL sales price and approximately 4 percent of our forecasted domestic NGL sales have been hedged with fixed-price swap contracts. The natural gas shrink requirements associated with the sales under the fixed-price swap contracts have also been hedged through Gas Marketing Services with physical gas purchase contracts, thus effectively hedging the margin on the volumes associated with fixed price swap contracts at a level about two times our rolling five-year average and approximating our 2007 average.
- Margins in our olefins business are highly dependent upon continued economic growth within the United States and any significant slow down in the economy would reduce the demand for the petrochemical products we produce in both Canada and the United States. Based on our increased ownership in our Geismar facility, we anticipate results from our olefins business to be above 2007 levels.
- Gathering and processing fee revenues in our West region in 2008 are expected to be at or slightly above levels of previous years due to continued strong drilling activities in our core basins.
- We expect fee revenues in our Gulf Coast region to increase in 2008 as we expand our Devil's Tower infrastructure to serve the Blind Faith and Bass Lite prospects. This increase is expected to be partially offset by lower volumes in other deepwater areas due to natural declines. Fee revenues include gathering, processing, production handling and transportation fees.
- Revenues from deepwater production areas are often subject to risks associated with the interruption and timing of product flows which can be influenced by weather and other third-party operational issues.
- The construction of deepwater pipelines is subject to the risk of pipe collapse from stresses during installation as well as from high hydrostatic pressure that could delay completion and increase costs. Our Perdido Norte project is located in the Gulf Coast region in the deepwater Gulf of Mexico and subject to these risks.

- We will continue to invest in facilities in the growth basins in which we provide services. We expect continued expansion of our gathering and processing systems in our Gulf Coast and West regions to keep pace with increased demand for our services. As we pursue these activities, our operating and general and administrative expenses are expected to increase.
- We expect continued expansion in the deepwater areas of the Gulf of Mexico to contribute to our future segment revenues and segment profit. We expect these additional fee-based revenues to lower our proportionate exposure to commodity price risks.
- The Venezuelan government continues its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and has expropriated privately held assets within the energy and telecommunications sector, escalating our concern regarding political risk in Venezuela.
- Our right of way agreement with the Jicarilla Apache Nation (JAN), which covered certain gathering system assets in Rio Arriba County of northern New Mexico, expired on December 31, 2006. We currently operate our gathering assets on the JAN lands pursuant to a special business license granted by the JAN which expires February 29, 2008. We are engaged in discussions with the JAN designed to result in the sale of our gathering assets which are located on or are isolated by the JAN lands. Provided the parties are able to reach an acceptable value on the sale of the subject gathering assets, our expectation is that we will nonetheless maintain partial revenues associated with gathering and processing downstream of the JAN lands and continue to operate the gathering assets on the JAN lands for an undetermined period of time beyond February 29, 2008. Based on current estimated gathering volumes and range of annual average commodity prices over the past five years, we estimate that gas produced on or isolated by the JAN lands represents approximately $20 million to $30 million of the West region’s annual gathering and processing revenue less related product costs.

Year-Over-Year Results

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Segment revenues	$ 5,180	$ 4,159	$ 3,291
Segment profit			
Domestic gathering & processing	897	631	389
Venezuela	89	98	95
Other	174	16	42
Indirect general and administrative expense	(88)	(70)	(66)
Total	$ 1,072	$ 675	$ 460

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.

2007 vs. 2006

The $1,021 million, or 25 percent, increase in *segment revenues* is largely due to:

- A $528 million increase in revenues from the marketing of NGLs and olefins;
- A $303 million increase in revenues from our olefins production business;
- A $244 million increase in revenues associated with the production of NGLs.

These increases are partially offset by a $35 million decrease in fee revenues.

Segment costs and expenses increased $645 million, or 18 percent, primarily as a result of:

- A $491 million increase in NGL and olefin marketing purchases;
- A $257 million increase in costs from our olefins production business;
- A $37 million increase in operating expenses including higher depreciation, maintenance, gathering fuel expenses and operating taxes;
- $24 million higher general and administrative expenses;
- A $10 million loss on impairment of the Carbonate Trend pipeline and an $8 million loss on impairment of certain other assets;
- The absence of $11 million of net gains on the sales of assets in 2006.

These increases are partially offset by;

- The absence of a 2006 charge of $73 million related to our Gulf Liquids litigation (see Note 15 of Notes to Consolidated Financial Statements);
- A $95 million decrease in costs associated with the production of NGLs due primarily to lower natural gas prices;
- $12 million income in 2007 from a favorable litigation outcome.

The $397 million, or 59 percent, increase in Midstream's *segment profit* reflects $339 million higher NGL margins and the absence of the previously mentioned $73 million Gulf Liquids litigation charge in 2006, as well as the other previously described changes in *segment revenues* and *segment costs and expenses.* A more detailed analysis of the segment profit of Midstream's various operations is presented as follows.

Domestic gathering & processing

The $266 million increase in *domestic gathering and processing segment profit* includes a $308 million increase in the West region, partially offset by a $42 million decrease in the Gulf Coast region.

The $308 million increase in our West region's *segment profit* primarily results from higher NGL margins, higher processing fee based revenues and income from a favorable litigation outcome, partially offset by higher operating expenses and lower gathering fee revenues. The significant components of this increase include the following:

- NGL margins increased $326 million in 2007 compared to 2006. This increase was driven by an increase in average per unit NGL prices, a decrease in costs associated with the production of NGLs reflecting lower natural gas prices and higher volumes due primarily to new capacity on the fifth cryogenic train at our Opal plant.
- Processing fee revenues increased $12 million. Processing volumes are higher due to customers electing to take liquids and pay processing fees.
- $12 million income in 2007 from a favorable litigation outcome.
- Gathering fee revenues decreased $6 million due primarily to natural volume declines and the shutdown of the Ignacio plant in the fourth quarter of 2007 as a result of the fire.
- Operating expenses increased $21 million including $9 million in higher depreciation, $9 million in higher treating plant and gathering fuel due primarily to the expiration of a favorable gas purchase contract, $5 million related to gas imbalance revaluation losses in the current year compared to gains in the prior year, $5 million higher leased compression costs and $4 million higher costs related to the Jicarilla lease arrangement. These were partially offset by the absence of a $7 million accounts payable accrual adjustment in 2006 and $5 million in lower system product losses.

The $42 million decrease in the Gulf Coast region's *segment profit* is primarily a result of lower volumes from our deepwater facilities, losses on impairments, and the absence of gains on assets in 2006, partially offset by higher NGL margins and higher other fee revenues. The significant components of this decrease include the following:

- Fee revenues from our deepwater assets decreased $40 million due primarily to declines in producers' volumes.
- A $10 million loss on impairment of the Carbonate Trend pipeline and a $6 million loss on impairment of certain other assets.
- The absence of $8 million in gains on the sales of certain gathering assets and a processing plant in 2006 and $5 million lower involuntary conversion gains resulting from insurance proceeds used to rebuild the Cameron Meadows plant.
- NGL margins increased $14 million driven by higher NGL prices, partially offset by lower NGL recoveries and an increase in costs associated with the production of NGLs.
- Other fee revenues increased $8 million driven by higher water removal fees.

Venezuela

Segment profit for our Venezuela assets decreased $9 million. The decrease is primarily due to the absence of a $9 million gain from the settlement of a contract dispute in 2006, $6 million lower fee revenues due primarily to the discontinuance in 2007 of revenue recognition related to labor escalation receivables, $7 million higher operating expenses, and $8 million higher bad debt expense related to labor escalation receivables, partially offset by $19 million of higher currency exchange gains and $1 million higher equity earnings.

Other

The significant components of the $158 million increase in *segment profit* of our other operations include the following:

- The absence of the previously mentioned $73 million Gulf Liquids litigation charge in 2006;
- $46 million in higher margins from our olefins production business due primarily to the increase in ownership of the Geismar olefins facility in July 2007 and higher prices of NGL products produced in our Canadian olefins operations;
- $18 million in higher margins related to the marketing of olefins and $21 million in higher margins related to the marketing of NGLs due to more favorable changes in pricing while product was in transit during 2007 as compared to 2006;
- An $8 million reversal of a maintenance accrual (see below);
- $9 million higher Aux Sable equity earnings primarily due to favorable processing margins;
- $11 million higher Discovery equity earnings primarily due to higher NGL margins and volumes.

These increases are partially offset by:

- $19 million in higher foreign exchange losses related to the revaluation of current assets held in U.S. dollars within our Canadian operations;
- The absence of a $4 million favorable transportation settlement in 2006.

Effective January 1, 2007, we adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities.* As a result, we recognized as other income an $8 million reversal of an accrual for major maintenance on our Geismar ethane cracker. We did not apply the FSP retrospectively because the impact to our first quarter 2007 and estimated full year 2007 earnings, as well as the impact to prior periods, is not material. We have adopted the deferral method for accounting for these costs going forward.

Indirect general and administrative expense

The $18 million, or 26 percent, increase in indirect general and administrative expense is due primarily to higher technical support services and other charges for various administrative support functions and higher employee expenses.

2006 vs. 2005

The $868 million, or 26 percent, increase in *segment revenues* is largely due to:

- A $561 million increase in crude marketing revenues, which is offset by a similar change in costs, resulting from additional deepwater production coming on-line in November 2005;
- A $165 million increase in revenues associated with the production of NGLs, primarily due to higher NGL prices combined with higher volumes;
- A $137 million increase in the marketing of NGLs and olefins, which is offset by a similar change in costs;
- An $83 million increase in fee-based revenues including $52 million in higher production handling revenues;
- A $44 million increase in revenues in our olefins unit due to higher volumes.

These increases were partially offset by an $84 million reduction in NGL revenues due to a change in classification of NGL transportation and fractionation expenses from costs of goods sold to net revenues (offset in costs and operating expenses).

Segment costs and expenses increased $688 million, or 23 percent, primarily as a result of:

- A $561 million increase in crude marketing purchases, which is offset by a similar change in revenues;
- A $137 million increase in NGL and olefins marketing purchases, offset by a similar change in revenues;
- An $82 million increase in operating expenses including an $11 million accounts payable accrual adjustment, higher system losses, depreciation, insurance expense, personnel and related benefit expenses, turbine overhauls, materials and supplies, compression and post-hurricane inspection and survey costs required by a government agency;
- A $59 million increase in other expense including the $73 million charge related to the Gulf Liquids litigation, partially offset by a $9 million favorable settlement of a contract dispute;
- A $20 million increase in costs associated with production in our olefins unit.

These increases were partially offset by:

- An $84 million reduction in NGL transportation and fractionation expenses due to the above-noted change in classification (offset in revenues);
- A $77 million decrease in plant fuel and costs associated with the production of NGLs due primarily to lower gas prices.

The $215 million, or 47 percent, increase in Midstream *segment profit* is primarily due to higher NGL margins, higher deepwater production handling revenues, higher gathering and processing revenues, higher margins from our olefins unit, and a settlement of an international contract dispute, and the absence of a $23 million impairment of our equity investment in Aux Sable Liquid Products L.P. (Aux Sable) recorded in 2005. These increases were largely offset by the $73 million charge related to the Gulf Liquids litigation contingency combined with higher operating costs and lower margins related to the marketing of olefins and NGLs. A more detailed analysis of the *segment profit* of Midstream's various operations is presented as follows.

Domestic gathering & processing

The $242 million increase in *domestic gathering and processing segment profit* includes a $138 million increase in the West region and a $104 million increase in the Gulf Coast region.

The $138 million increase in our West region's *segment profit* primarily results from higher product margins and higher gathering and processing revenues, partially offset by higher operating expenses. The significant components of this increase include the following:

- NGL margins increased $166 million compared to 2005. This increase was driven by a decrease in costs associated with the production of NGLs, an increase in average per unit NGL prices and higher volumes resulting from lower NGL recoveries during the fourth quarter of 2005 caused by intermittent periods of uneconomical market commodity prices and a power outage and associated operational issues at our Opal, Wyoming facility. NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, and transportation and fractionation expense.
- Gathering and processing fee revenues increased $26 million. Gathering fees are higher as a result of higher average per-unit gathering rates. Processing volumes are higher due to customers electing to take liquids and pay processing fees.
- Operating expenses increased $51 million including $11 million in higher net system product losses as a result of system gains in 2005 compared to losses in 2006, a $7 million accounts payable accrual adjustment; $8 million in higher personnel and related benefit expenses; $6 million in higher materials and supplies; $6 million in higher gathering fuel, $4 million in higher leased compression costs; $4 million in higher turbine overhaul costs; and $4 million in higher depreciation.

The $104 million increase in the Gulf Coast region's *segment profit* is primarily a result of higher NGL margins, higher volumes from our deepwater facilities, partially offset by higher operating expenses. The significant components of this increase include the following:

- NGL margins increased $77 million compared to 2005. This increase was driven by an increase in average per unit NGL prices and a decrease in costs associated with the production of NGLs.
- Fee revenues from our deepwater assets increased $52 million as a result of $51 million in higher volumes flowing across the Devils Tower facility and $22 million in higher Devils Tower unit-of-production rates recognized as a result of a new reserve study. These increases are partially offset by a $21 million decline in other gathering and production handling revenues due to volume declines in other areas.
- Operating expenses increased $25 million primarily as a result of $12 million in higher insurance costs, $4 million in higher depreciation expense on our deepwater assets, $3 million in higher net system product losses as a result of lower gain volumes in 2006, $2 million in post-hurricane inspection and survey costs required by a government agency, and a $1 million accounts payable accrual adjustment.

Venezuela

Segment profit for our Venezuela assets increased $3 million and includes $9 million resulting from the settlement of a contract dispute and $1 million in higher revenues due to higher natural gas volumes and prices at our compression facility. These are partially offset by $4 million in higher expenses related to higher insurance, personnel and contract labor costs and a $2 million increase in the reserve for uncollectible accounts.

Other

The $26 million decrease in *segment profit* of our other operations is largely due to the $73 million of charges related to the Gulf Liquids litigation contingency combined with $13 million in lower margins related to the marketing of olefins. The decrease also reflects $12 million in lower margins related to the marketing of NGLs due to more favorable changes in pricing while product was in transit during 2005 as compared to 2006. These were partially offset by the absence of a $23 million impairment of our equity investment in Aux Sable in 2005, $24 million in higher margins in our olefins unit, $7 million in higher earnings from our equity investment in

Discovery Producer Services, L.L.C. (Discovery), $7 million in higher fractionation, storage and other fee revenues, and a $4 million favorable transportation settlement.

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. 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, and provides services to third parties, such as producers.

Overview of 2007

Gas Marketing's operating results for 2007 were primarily driven by a loss of approximately $166 million related to certain legacy derivative natural gas contracts that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in December 2007. In addition, a decrease in forward natural gas basis prices against a net long legacy derivative position contributed to the losses as well.

Outlook for 2008

For 2008, Gas Marketing intends to focus on providing services that support our natural gas businesses. Certain legacy natural gas contracts and positions from our former Power segment remain in the Gas Marketing segment. 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. However, this mark-to-market volatility is expected to be significantly reduced compared with previous levels.

Year-Over-Year Results

	Years Ended December 31,		
	2007	2006 (Millions)	2005
Realized revenues	$ 4,948	$ 5,185	$ 6,147
Net forward unrealized mark-to-market gains (losses)	(315)	(136)	188
Segment revenues	4,633	5,049	6,335
Costs and operating expenses	4,937	5,258	6,238
Gross margin	(304)	(209)	97
Selling, general and administrative (income) expense	13	(13)	(1)
Other (income) expense — net	20	(1)	89
Segment profit (loss)	$ (337)	$ (195)	$ 9

2007 vs. 2006

Realized revenues represent (1) revenue from the sale of natural gas and (2) gains and losses from the net financial settlement of derivative contracts. *Realized revenues* decreased $237 million primarily due to a decrease in net financial settlements of derivative contracts. This is partially offset by an increase in physical natural gas revenue as a result of a 9 percent increase in natural gas sales volumes partially offset by a 6 percent decrease in average prices on physical natural gas sales.

Net forward unrealized mark-to-market gains (losses) primarily represent changes in the fair values of certain legacy 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. A $156 million loss related to a legacy derivative natural gas sales contract, that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in

December 2007, primarily caused the unfavorable change in *net forward unrealized mark-to-market gains (losses)*. Prior to the execution of the asset transfer agreement, we accounted for this legacy contract on an accrual basis under the normal purchases and normal sales exception of SFAS 133. Due to the pending assignment of the legacy contract, we no longer consider the contract to be in the normal course of business. Therefore, we recognized a loss to reflect the current negative fair value of the contract. In addition, losses on gas purchase contracts caused by a decrease in forward natural gas prices were greater in 2007 than in 2006.

The $321 million decrease in Gas Marketing's *costs and operating expenses* is primarily due to a 7 percent decrease in average prices on physical natural gas purchases, partially offset by a 4 percent increase in natural gas purchase volumes.

The unfavorable change in *selling, general and administrative (income) expense* is due primarily to the absence of a $25 million gain from the sale of certain receivables to a third party in 2006.

Other (income) expense — net in 2007 includes a $20 million accrual for litigation contingencies.

The $142 million increase in *segment loss* is primarily due to the loss recognized on a legacy derivative sales contract previously treated as a normal purchase and normal sale, a $20 million accrual for litigation contingencies, and the absence of a $25 million gain from the sale of certain receivables as described above, partially offset by an improvement in accrual gross margin.

2006 vs. 2005

Realized revenues decreased $962 million primarily due to a 17 percent decrease in average prices on physical natural gas sales.

The effect of a change in forward prices on legacy natural gas derivative contracts primarily caused the $324 million unfavorable change in *net forward unrealized mark-to-market gains (losses)*. A decrease in forward natural gas prices during 2006 caused losses on legacy net forward gas fixed-price purchase contracts, while an increase in forward natural gas prices during 2005 caused gains on legacy net forward gas fixed-price purchase contracts.

The $980 million decrease in Gas Marketing's *costs and operating expenses* is primarily due to an 18 percent decrease in average prices on physical natural gas purchases.

The favorable change in *selling, general and administrative (income) expense* is due primarily to increased gains from the sale of certain receivables to a third party. Gas Marketing recognized a $25 million gain in 2006 compared to a $10 million gain in 2005.

Other (income) expense — net in 2005 includes an $82 million accrual for estimated litigation contingencies, primarily associated with agreements reached to substantially resolve exposure related to natural gas price and volume reporting issues (see Note 15 of Notes to Consolidated Financial Statements) and a $5 million accrual for a regulatory settlement.

The $204 million change from a *segment profit* to a *segment loss* is primarily due to the effect of a change in forward prices on legacy natural gas derivative contracts, partially offset by favorable changes in *other (income) expense — net* described above.

Other

Year-Over-Year Operating Results

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Segment revenues	$ 26	$ 27	$ 27
Segment loss	$ (1)	$ (13)	$ (123)

2007 vs. 2006

The improvement in *segment loss* for 2007 is primarily driven by $5 million of net gains on the sale of land.

2006 vs. 2005

Other *segment loss* for 2005 includes $87 million of impairment charges, of which $38 million was recorded during the fourth quarter, related to our investment in Longhorn. In a related matter, we wrote off $4 million of capitalized project costs associated with Longhorn. We also recorded $24 million of equity losses associated with our investment in Longhorn. Partially offsetting these charges and losses was a $9 million fourth quarter gain on the sale of land.

Energy Trading Activities

Fair Value of Trading and Nontrading Derivatives

The chart below reflects the fair value of derivatives held for trading purposes as of December 31, 2007. We have presented the fair value of assets and liabilities by the period in which they would be realized under their contractual terms and not as a result of a sale. We have reported the fair value of a portion of these derivatives in assets and liabilities of discontinued operations. (See Note 2 of Notes to Consolidated Financial Statements.)

Net Assets (Liabilities) — Trading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$(1)	$ (1)	$ (1)	$ (1)	$ —	$ (4)

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of nontrading derivative contracts. Nontrading derivative contracts are those that hedge or could possibly hedge forecasted transactions on an economic basis. We have designated certain of these contracts as cash flow hedges of Exploration & Production's forecasted sales of natural gas production and Midstream's forecasted sales of natural gas liquids under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net liability value of $268 million as of December 31, 2007. The chart below reflects the fair value of derivatives held for nontrading purposes as of December 31, 2007, for Gas Marketing Services, Exploration & Production, Midstream, and nontrading derivatives reported in assets and liabilities of discontinued operations.

Net Assets (Liabilities) — Nontrading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$(87)	$ (268)	$ (8)	$ (1)	$ —	$ (364)

Methods of Estimating Fair Value

Most of the derivatives we hold settle in active periods and markets in which quoted market prices are available. These include futures contracts, option contracts, swap agreements and physical commodity purchases and sales in the commodity markets in which we transact. While an active market may not exist for the entire period, quoted prices can generally be obtained for natural gas through 2012.

These prices reflect current economic and regulatory conditions and may change because of market conditions. The availability of quoted market prices in active markets varies between periods and commodities based upon changes in market conditions. The ability to obtain quoted market prices also varies greatly from region to region. The time periods noted above are an estimation of aggregate availability of quoted prices. An immaterial portion of our total net derivative liability value of $368 million relates to periods in which active quotes cannot be obtained. We estimate energy commodity prices in these illiquid periods by incorporating information about commodity prices in actively quoted markets, quoted prices in less active markets, and other market fundamental analysis. Modeling and other valuation techniques, however, are not used significantly in determining the fair value of our derivatives.

Counterparty Credit Considerations

We include an assessment of the risk of counterparty nonperformance in our estimate of fair value for all contracts. Such assessment considers (1) the credit rating of each counterparty as represented by public rating agencies such as Standard & Poor's and Moody's Investors Service, (2) the inherent default probabilities within these ratings, (3) the regulatory environment that the contract is subject to and (4) the terms of each individual contract.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We continually assess this risk. We have credit protection within various agreements to call on additional collateral support if necessary. At December 31, 2007, we held collateral support, including letters of credit, of $215 million.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2007 and 2006, we did not incur any significant losses due to recent counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations (see Note 2 of Notes to Consolidated Financial Statements), as of December 31, 2007, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 78	$ 79
Energy marketers and traders	224	1,328
Financial institutions	1,302	1,302
Other	—	1
	$ 1,604	2,710
Credit reserves		(1)
Gross credit exposure from derivatives		$ 2,709

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 December 31, 2007, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 17	$ 17
Energy marketers and traders	18	20
Financial institutions	45	45
Other	—	—
	$ 80	82
Credit reserves		(1)
Net credit exposure from derivatives		$ 81

(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. We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, adequate parent company guarantees, and property interests, as investment grade.

Trading Policy

We have policies and procedures that govern our trading and risk management activities. These policies cover authority and delegation thereof in addition to control requirements, authorized commodities and term and exposure limitations. Value-at-risk is limited in aggregate and calculated at a 95 percent confidence level.

Management's Discussion and Analysis of Financial Condition

Outlook

We believe we have, or have access to, the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures and debt payments while maintaining a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds. We also expect to maintain our investment grade status. In 2008, we expect to maintain liquidity from cash and cash equivalents and unused revolving credit facilities of at least $1 billion. We maintain adequate liquidity to manage margin requirements related to significant movements in commodity prices, unplanned capital spending needs, near term scheduled debt payments, and litigation and other settlements. We expect to fund capital and investment expenditures, debt payments, dividends, stock repurchases and working capital requirements through cash flow from operations, which is currently estimated to be between $2.3 billion and $2.7 billion in 2008, proceeds from debt issuances and sales of units of Williams Partners L.P. and Williams Pipeline Partners L.P., as well as cash and cash equivalents on hand as needed.

We enter 2008 positioned for continued growth through disciplined investments in our natural gas businesses. Examples of this planned growth include:

- Exploration & Production will continue to maintain its development drilling program in its key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth.
- Gas Pipeline will continue to expand its system to meet the demand of growth markets.
- Midstream will continue to pursue significant deepwater production commitments and expand capacity in the western United States.

We estimate capital and investment expenditures will total approximately $2.6 billion to $2.9 billion in 2008. As a result of increasing our development drilling program, $1.45 billion to $1.65 billion of the total estimated 2008 capital expenditures is related to Exploration & Production. Also within the total estimated expenditures for 2008 is approximately $180 million to $260 million for compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance. Commitments for construction and acquisition of property, plant and equipment are approximately $484 million at December 31, 2007.

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 due to commodity pricing volatility. To mitigate this exposure, Exploration & Production has fixed-price hedges for approximately 70 MMcfe per day of its expected 2008 production. In addition, Exploration & Production has collar agreements for 2008 which hedge approximately 397 MMcfe per day of expected 2008 production.
- Sensitivity of margin requirements associated with our marginable commodity contracts. As of December 31, 2007, we estimate our exposure to additional margin requirements through 2008 to be no more than $125 million, using a statistical analysis at a 99 percent confidence level.

- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 15 of Notes to Consolidated Financial Statements).
- The impact of a general economic downturn, including any associated volatility in the credit markets and our access to liquidity and the capital markets.

In August 2006, the Pension Protection Act of 2006 was signed into law. The Act makes significant changes to the requirements for employer-sponsored retirement plans, including revisions affecting the funding of defined benefit pension plans beginning in 2008. We have assessed the impact of the legislation on our future funding requirements and do not expect a significant increase in minimum funding requirements over current levels, assuming long-term rates of return on assets and current discount rates do not experience a significant decline.

Overview

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior notes due 2010. Northwest Pipeline paid premiums of approximately $7 million in conjunction with the early debt retirement.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement. Northwest Pipeline initiated an exchange offer on July 26, 2007, which expired on August 23, 2007. Northwest Pipeline received full participation in the exchange offer. (See Note 11 of Notes to Consolidated Financial Statements.)

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. We plan to fund this program with cash on hand. In 2007, we purchased approximately 16 million shares for $526 million under the program at an average cost of $33.08 per share.

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. In February 2008, the underwriters also exercised their right to purchase an additional 1.65 million common units at the same price. A subsidiary of ours serves as the general partner of WMZ. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. Upon completion of the transaction, we hold approximately 47.7 percent of the interests in WMZ, including the interests of the general partner.

In December 2007, Williams Partners L.P. acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million. Williams Partners L.P. completed the transaction after successfully closing a public equity offering of 9.25 million common units that yielded net proceeds of approximately $335 million. The partnership financed the remainder of the purchase price primarily through utilizing $250 million of term loan borrowings and issuing approximately $157 million of common units to us. The $250 million term loan is under Williams Partners L.P.'s new $450 million five-year senior unsecured credit facility that became effective simultaneous with the closing of the Wamsutter transaction. The remaining $200 million of capacity under the new facility is available for revolving credit borrowings.

In December 2007, we repurchased $213 million of our 7.125 percent senior unsecured notes due September 2011 and $22 million of our 8.125 percent senior unsecured notes due March 2012. In conjunction with these early retirements, we paid premiums of approximately $19 million. These premiums, as well as related fees and expenses are recorded as *early debt retirement costs* in the Consolidated Statement of Income.

Credit ratings

On March 19, 2007, Standard & Poor's raised our senior unsecured debt rating from a BB− to a BB with a stable ratings outlook. On May 21, 2007, Standard & Poor's revised its ratings outlook to positive from stable. On November 9, 2007, Standard & Poor's raised our senior unsecured debt rating from a BB to a BB+ and our corporate credit rating from a BB+ to a BBB− with a ratings outlook of stable. 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.

On May 21, 2007, Moody's Investors Service placed our ratings under review for possible upgrade. On November 15, 2007, Moody's Investors Service raised our senior unsecured debt rating from a Ba2 to a Baa3 with a ratings outlook of stable. 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. A "Ba" rating indicates an obligation that is judged to have speculative elements and is subject to substantial credit risk. The "1", "2" and "3" modifiers show the relative standing within a major category. A "1" indicates that an obligation ranks in the higher end of the broad rating category, "2" indicates a mid-range ranking, and "3" ranking at the lower end of the category.

On May 21, 2007, Fitch Ratings revised its ratings outlook to positive from stable. On November 20, 2007, Fitch Ratings raised our senior unsecured debt rating from a BB+ to a BBB− with a ratings outlook of stable. With respect to Fitch, a rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" is considered speculative grade. A "BB" rating from Fitch indicates that there is a possibility of credit risk developing, particularly as the result of adverse economic change over time; however, business or financial alternatives may be available to allow financial commitments to be met. Fitch may add a "+" or a "− " sign to show the obligor's relative standing within a major rating category.

Liquidity

Our internal and external sources of liquidity include cash generated from our operations, bank financings, and proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. While most of our sources are available to us at the parent level, others are available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. and Williams Pipeline Partners L.P. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

Available Liquidity

	Year Ended December 31, 2007 (Millions)
Cash and cash equivalents*	$ 1,699
Securities	20
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion	858
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility**	1,222
Available capacity under Williams Partners L.P.'s $450 million five-year senior unsecured credit facility (see previous discussion)	200
	$ 3,999

* *Cash and cash equivalents* includes $10 million of funds received from third parties as collateral. The obligation for these amounts is reported in *accrued liabilities* on the Consolidated Balance Sheet. Also included is $475 million of cash and cash equivalents that is being utilized by certain subsidiary and international operations.

** Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. In 2007, Northwest Pipeline borrowed $250 million under this facility to retire matured notes, and in January 2008, Transco borrowed $100 million.

In addition to the above, Northwest Pipeline and Transco have shelf registration statements available for the issuance of up to $350 million aggregate principal amount of debt securities. If the credit rating of Northwest Pipeline or Transco is below investment grade for all credit rating agencies, they can only use their shelf registration statements to issue debt if such debt is guaranteed by us.

Williams Partners L.P. has a shelf registration statement available for the issuance of approximately $1.2 billion aggregate principal amount of debt and limited partnership unit securities.

In addition, at the parent-company level, we have a shelf registration statement that allows us to issue publicly registered debt and equity securities as needed.

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks which serves to reduce our usage of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. (See Note 11 of Notes to Consolidated Financial Statements.)

On May 9, 2007, we amended our $1.5 billion unsecured credit facility extending the maturity date from May 1, 2009 to May 1, 2012. Applicable borrowing rates and commitment fees for investment grade credit ratings were also modified.

Sources (Uses) of Cash

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 2,237	$ 1,890	$ 1,450
Financing activities	(511)	1,103	36
Investing activities	(2,296)	(2,321)	(819)
Increase (decrease) in cash and cash equivalents	$ (570)	$ 672	$ 667

Operating Activities

Our *net cash provided by operating activities* in 2007 increased from 2006 due primarily to the increase in our operating results and the absence of a $145 million securities litigation settlement payment in 2006. These increases are partially offset by increased income tax payments in 2007 and other changes in working capital.

Our *net cash provided by operating activities* in 2006 increased from 2005 due largely to higher operating income at Midstream, partially offset by a $145 million securities litigation settlement payment in fourth quarter 2006.

Financing Activities

2007

See Overview, within this section, for a discussion of 2007 debt issuances, retirements, stock repurchases, and additional financing by Williams Partners L.P.

Quarterly dividends paid on common stock increased from $.09 to $.10 per common share during the second quarter of 2007 and totaled $233 million for year ended December 31, 2007.

2006

- Transco issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016.
- Northwest Pipeline issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016.
- Williams Partners L.P. acquired our interest in Williams Four Corners LLC for $1.6 billion. The acquisition was completed after Williams Partners L.P. successfully closed a $150 million private debt offering of 7.5 percent senior unsecured notes due 2011, a $600 million private debt offering of 7.25 percent senior unsecured notes due 2017, $350 million of common and Class B units, and equity offerings of $519 million in net proceeds.
- We paid $489 million to retire a secured floating-rate term loan due in 2008.
- We paid $26 million in premiums related to the conversion of $220 million of 5.5 percent junior subordinated convertible debentures into common stock.
- Quarterly dividends paid on common stock increased from $.075 to $.09 per share during the second quarter of 2006 and totaled $207 million for the year ended December 31, 2006.

2005

- We retired $200 million of 6.125 percent notes issued by Transco, which matured January 15, 2005.
- We received $273 million in *proceeds from the issuance of common stock* purchased under the FELINE PACS equity forward contracts.
- We completed an initial public offering of approximately 40 percent of our interest in Williams Partners L.P. resulting in net proceeds of $111 million.
- Quarterly dividends paid on common stock increased from $.05 to $.075 per common share during the third quarter of 2005 and totaled $143 million for the year ended December 31, 2005.

Investing Activities

2007

- Capital expenditures totaled $2.8 billion and were primarily related to Exploration & Production’s drilling activity, mostly in the Piceance basin.
- We received $496 million of gross proceeds from the sale of substantially all of our power business.
- We purchased $304 million and received $353 million from the sale of auction rate securities.

2006

- Capital expenditures totaled $2.5 billion and were primarily related to Exploration & Production’s drilling activity, mostly in the Piceance basin, and Northwest Pipeline’s capacity replacement project.
- We purchased $386 million and received $414 million from the sale of auction rate securities.

2005

- Capital expenditures totaled $1.3 billion and were primarily related to Exploration & Production’s drilling activity, mostly in the Piceance basin, and Gas Pipeline’s normal maintenance and compliance.
- We received $310 million in proceeds from the Gulfstream recapitalization.

- We purchased $224 million and received $138 million from the sale of auction rate securities.
- Northwest Pipeline received an $88 million contract termination payment, representing reimbursement of the net book value of the related assets.
- We received $55 million proceeds from the sale of our note with Williams Communications Group, our previously owned subsidiary.

Off-balance sheet financing arrangements and guarantees of debt or other commitments

We have various other guarantees and commitments which are disclosed in Notes 2, 3, 10, 11, 14, and 15 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.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations, including obligations related to discontinued operations.

	2008	2009-2010	2011-2012	Thereafter	Total
			(Millions)		
Long-term debt, including current portion:					
Principal	$ 138	$ 92	$ 2,531	$ 5,160	$ 7,921
Interest	585	1,142	1,011	4,743	7,481
Capital leases	6	6	—	—	12
Operating leases	84	94	28	19	225
Purchase obligations(1)	1,351	1,347	1,297	2,859	6,854
Other long-term liabilities, including current portion:					
Physical and financial derivatives(2)(3)	478	661	269	321	1,729
Other(4)(5)	5	1	—	—	6
Total	$ 2,647	$ 3,343	$ 5,136	$ 13,102	$ 24,228

(1) Includes $4.4 billion of natural gas purchase obligations at market prices at our Exploration & Production segment. The purchased natural gas can be sold at market prices.

(2) The obligations for physical and financial derivatives are based on market information as of December 31, 2007. Because market information changes daily and has the potential to be volatile, significant changes to the values in this category may occur.

(3) Expected offsetting cash inflows of $5.6 billion at December 31, 2007, resulting from product sales or net positive settlements, are not reflected in these amounts. In addition, product sales may require additional purchase obligations to fulfill sales obligations that are not reflected in these amounts.

(4) Does not include estimated contributions to our pension and other postretirement benefit plans. We made contributions to our pension and other postretirement benefit plans of $56 million in 2007 and $57 million in 2006. In 2008, we expect to contribute approximately $56 million to these plans (see Note 7 of Notes to Consolidated Financial Statements), including $40 million to our tax-qualified pension plans. There were no minimum funding requirements to our tax-qualified pension plans in 2007 or 2006, and we do not expect any minimum funding requirements in 2008. We anticipate that future contributions will not vary significantly from recent historical contributions, assuming actual results do not differ significantly from estimated results for assumptions such as discount rates, returns on plan assets, retirement rates, mortality and other significant assumptions, and assuming no further changes in current and prospective legislation and regulations. Based on these anticipated levels of future contributions, we do not expect to trigger any minimum funding requirements in the future; however, we may elect to make contributions to increase the funded status of our plans.

(5) On January 1, 2007, we adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes." As of December 31, 2007, we have accrued approximately $76 million for unrecognized tax benefits. We cannot make reasonably reliable estimates of the timing of the future payments of these liabilities. Therefore, these liabilities have been excluded from the table above. See Note 5 of Notes to Consolidated Financial Statements for information regarding our contingent tax liability reserves.

Effects of Inflation

Our operations have benefited from relatively low inflation rates. Approximately 42 percent of our gross property, plant and equipment is at Gas Pipeline and the remainder is at other operating units. Gas Pipeline is subject to regulation, which limits recovery to historical cost. While amounts in excess of historical cost are not recoverable under current FERC practices, we anticipate being allowed to recover and earn a return based on increased actual cost incurred to replace existing assets. Cost-based regulation, along with competition and other market factors, may limit our ability to recover such increased costs. For the other operating units, operating costs are influenced to a greater extent by both competition for specialized services and specific price changes in oil and natural gas and related commodities than by changes in general inflation. Crude, natural gas, and natural gas liquids prices are particularly sensitive to OPEC production levels and/or the market perceptions concerning the supply and demand balance in the near future. However, our exposure to these price changes is reduced through the use of hedging instruments.

Environmental

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations and/or remedial processes at certain sites, some of which we currently do not own. (See Note 15 of Notes to Consolidated Financial Statements.) We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Current estimates of the most likely costs of such activities are approximately $46 million, all of which are recorded as liabilities on our balance sheet at December 31, 2007. We will seek recovery of approximately $13 million of the accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2007, we paid approximately $14 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $15 million in 2008 for these activities. Estimates of the most likely costs of cleanup are generally based on completed assessment studies, preliminary results of studies or our experience with other similar cleanup operations. At December 31, 2007, certain assessment studies were still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

We are subject to the federal Clean Air Act and to the federal Clean Air Act Amendments of 1990, which require the EPA to issue new regulations. We are also subject to regulation at the state and local level. In September 1998, the EPA promulgated rules designed to mitigate the migration of ground-level ozone in certain states. In March 2004 and June 2004, the EPA promulgated additional regulation regarding hazardous air pollutants, which may impose additional controls. Capital expenditures necessary to install emission control devices on our Transco gas pipeline system to comply with rules were approximately $3 million in 2007 and are estimated to be between $25 million and $30 million through 2010. The actual costs incurred will depend on the final implementation plans developed by each state to comply with these regulations. We consider these costs on our Transco system associated with compliance with these environmental laws and regulations to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through its rates.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. The majority of our debt portfolio is comprised of fixed rate debt in order to mitigate the impact of fluctuations in interest rates. The maturity of our long-term debt portfolio is partially influenced by the expected lives of our operating assets.

The tables below provide information about our interest rate risk-sensitive instruments as of December 31, 2007 and 2006. Long-term debt in the tables represents principal cash flows, net of (discount) premium, and weighted-average interest rates by expected maturity dates. The fair value of our publicly traded long-term debt is valued using indicative year-end traded bond market prices. Private debt is valued based on the prices of similar securities with similar terms and credit ratings.

	2008	2009	2010	2011	2012	Thereafter(1)	Total	Fair Value December 31, 2007
					(Dollars in millions)			
Long-term debt, including current portion(4):								
Fixed rate	$ 53	$ 41	$ 27	$ 948	$ 971	$ 5,111	$ 7,151	$ 7,994
Interest rate	7.7%	7.7%	7.4%	7.4%	7.3%	7.7%		
Variable rate	$ 85	$ 12	$ 12	$ 7	$ 605(5)	$ 18	$ 739	$ 735
Interest rate(2)								

	2007	2008	2009	2010	2011	Thereafter(1)	Total	Fair Value December 31, 2006
					(Dollars in millions)			
Long-term debt, including current portion(4):								
Fixed rate	$ 381	$ 153	$ 41	$ 205	$ 1,161	$ 5,922	$ 7,863	$ 8,343
Interest rate	7.7%	7.7%	7.7%	7.5%	7.6%	7.8%		
Variable rate	$ 10	$ 85	$ 12	$ 12	$ 7	$ 23	$ 149	$ 137
Interest rate(3)								

(1) Includes unamortized discount and premium.

(2) The interest rate at December 31, 2007, is LIBOR plus 1 percent.

(3) The interest rate at December 31, 2006 was LIBOR plus 1 percent.

(4) Excludes capital leases.

(5) Includes Transco's subsequent refinancing of its $100 million notes, due on January 15, 2008, under our $1.5 billion revolving credit facility. (See Note 11 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 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. Our value at risk for contracts held for trading purposes was approximately $1 million at both December 31, 2007 and 2006. During the year ended December 31, 2007, our value at risk for these contracts ranged from a high of $2 million to a low of $1 million.

Nontrading

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

Segment	Commodity Price Risk Exposure
Exploration & Production	• Natural gas sales
Midstream	• Natural gas purchases
	• NGL sales
Gas Marketing Services	• Natural gas purchases and sales

The value at risk for derivative contracts held for nontrading purposes was $24 million at December 31, 2007 and $12 million at December 31, 2006. During the year ended December 31, 2007, our value at risk for these contracts ranged from a high of $24 million to a low of $7 million. The increase in value at risk reflects the impact on our nontrading portfolio of the sale of substantially all of our power business in November 2007.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 133. Though these contracts are included in our value-at-risk calculation, any change in the fair value of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Foreign Currency Risk

We have international investments that could affect our financial results if the investments incur a permanent decline in value as a result of changes in foreign currency exchange rates and/or the economic conditions in foreign countries.

International investments accounted for under the cost method totaled $24 million at December 31, 2007, and $42 million at December 31, 2006. These investments are primarily in nonpublicly traded companies for which it is not practicable to estimate fair value. We believe that we can realize the carrying value of these investments considering the status of the operations of the companies underlying these investments. If a 20 percent change occurred in the value of the underlying currencies of these investments against the U.S. dollar, the fair value at December 31, 2007, could change by approximately $5 million assuming a direct correlation between the currency fluctuation and the value of the investments.

Net assets of consolidated foreign operations, whose functional currency is the local currency, are located primarily in Canada and approximate 7 percent and 6 percent of our net assets at December 31, 2007 and 2006, respectively. These foreign operations do not have significant transactions or financial instruments denominated in other currencies. However, these investments do have the potential to impact our financial position, due to fluctuations in these local currencies arising from the process of re-measuring the local functional currency into the U.S. dollar. As an example, a 20 percent change in the respective functional currencies against the U.S. dollar could have changed *stockholders' equity* by approximately $88 million at December 31, 2007.

Item 8. ***Financial Statements and Supplementary Data***

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Williams' management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) and for the assessment of the effectiveness of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and board of directors regarding the preparation and fair presentation of financial statements in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and board of directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management assessed the effectiveness of Williams' internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework*. Management's assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of our internal control over financial reporting. Based on our assessment we believe that, as of December 31, 2007, Williams' internal control over financial reporting is effective based on those criteria.

Ernst & Young LLP, our independent registered public accounting firm, has audited our internal control over financial reporting, as stated in their report which is included in this Annual Report on Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders of
The Williams Companies, Inc.

We have audited The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Williams Companies, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, The Williams Companies, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of The Williams Companies, Inc. as of December 31, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007 of The Williams Companies, Inc. and our report dated February 22, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
The Williams Companies, Inc.

We have audited the accompanying consolidated balance sheet of The Williams Companies, Inc. as of December 31, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of The Williams Companies, Inc. at December 31, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As explained in Note 5 to the consolidated financial statements, effective January 1, 2007 the Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109*. Also, as explained in Note 1 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2008

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF INCOME

	Years Ended December 31,		
	2007	2006	2005
	(Millions, except per-share amounts)		
Revenues:			
Exploration & Production	$ 2,093	$ 1,488	$ 1,269
Gas Pipeline	1,610	1,348	1,413
Midstream Gas & Liquids	5,180	4,159	3,291
Gas Marketing Services	4,633	5,049	6,335
Other	26	27	27
Intercompany eliminations	(2,984)	(2,695)	(2,554)
Total revenues	10,558	9,376	9,781
Segment costs and expenses:			
Costs and operating expenses	8,079	7,566	7,885
Selling, general and administrative expenses	471	389	277
Other (income) expense — net	(18)	34	57
Total segment costs and expenses	8,532	7,989	8,219
General corporate expenses	161	132	145
Securities litigation settlement and related costs	—	167	9
Operating income (loss):			
Exploration & Production	731	530	568
Gas Pipeline	622	430	542
Midstream Gas & Liquids	1,011	635	455
Gas Marketing Services	(337)	(195)	9
Other	(1)	(13)	(12)
General corporate expenses	(161)	(132)	(145)
Securities litigation settlement and related costs	—	(167)	(9)
Total operating income	1,865	1,088	1,408
Interest accrued	(685)	(670)	(667)
Interest capitalized	32	17	7
Investing income	257	168	25
Early debt retirement costs	(19)	(31)	—
Minority interest in income of consolidated subsidiaries	(90)	(40)	(26)
Other income — net	11	26	27
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	1,371	558	774
Provision for income taxes	524	211	301
Income from continuing operations	847	347	473
Income (loss) from discontinued operations	143	(38)	(157)
Income before cumulative effect of change in accounting principle	990	309	316
Cumulative effect of change in accounting principle	—	—	(2)
Net income	$ 990	$ 309	$ 314
Basic earnings (loss) per common share:			
Income from continuing operations	$ 1.42	$ .58	$ .82
Income (loss) from discontinued operations	.24	(.06)	(.27)
Income before cumulative effect of change in accounting principle	1.66	.52	.55
Cumulative effect of change in accounting principle	—	—	—
Net income	$ 1.66	$ .52	$ .55
Weighted-average shares (thousands)	596,174	595,053	570,420
Diluted earnings (loss) per common share:			
Income from continuing operations	$ 1.40	$ .57	$ .79
Income (loss) from discontinued operations	.23	(.06)	(.26)
Income before cumulative effect of change in accounting principle	1.63	.51	.53
Cumulative effect of change in accounting principle	—	—	—
Net income	$ 1.63	$ .51	$ .53
Weighted-average shares (thousands)	609,866	608,627	605,847

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

	December 31, 2007	December 31, 2006
	(Dollars in millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,699	$ 2,269
Accounts and notes receivable (net of allowance of $27 in 2007 and $15 in 2006)	1,192	981
Inventories	209	238
Derivative assets	1,736	1,286
Assets of discontinued operations	185	837
Deferred income taxes	199	337
Other current assets and deferred charges	318	374
Total current assets	5,538	6,322
Investments	901	866
Property, plant and equipment — net	15,981	14,158
Derivative assets	859	1,844
Goodwill	1,011	1,011
Assets of discontinued operations	—	565
Other assets and deferred charges	771	636
Total assets	$ 25,061	$ 25,402
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,131	$ 906
Accrued liabilities	1,158	1,353
Derivative liabilities	1,824	1,304
Liabilities of discontinued operations	175	739
Long-term debt due within one year	143	392
Total current liabilities	4,431	4,694
Long-term debt	7,757	7,622
Deferred income taxes	2,996	2,880
Derivative liabilities	1,139	1,920
Liabilities of discontinued operations	—	147
Other liabilities and deferred income	933	985
Contingent liabilities and commitments (Note 15)		
Minority interests in consolidated subsidiaries	1,430	1,081
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 608 million shares issued at December 31, 2007, and 603 million shares issued at December 31, 2006)	608	603
Capital in excess of par value	6,748	6,605
Accumulated deficit	(293)	(1,034)
Accumulated other comprehensive loss	(121)	(60)
	6,942	6,114
Less treasury stock, at cost (22 million shares of common stock in 2007 and 6 million shares of common stock in 2006)	(567)	(41)
Total stockholders' equity	6,375	6,073
Total liabilities and stockholders' equity	$ 25,061	$ 25,402

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	Common Stock	Capital in Excess of Par Value	Accumulated Deficit	Accumulated Other Comprehensive Loss	Other	Treasury Stock	Total
	(Dollars in millions, except per-share amounts)						
Balance, December 31, 2004	$ 564	$ 6,006	$ (1,307)	$ (244)	$ (22)	$ (41)	$ 4,956
Comprehensive income:							
Net income — 2005	—	—	314	—	—	—	314
Other comprehensive loss:							
Net unrealized losses on cash flow hedges, net of reclassification adjustments	—	—	—	(66)	—	—	(66)
Foreign currency translation adjustments	—	—	—	11	—	—	11
Minimum pension liability adjustment	—	—	—	1	—	—	1
Total other comprehensive loss							(54)
Total comprehensive income							260
Issuance of common stock and settlement of forward contracts as a result of FELINE PACS exchange	11	262	—	—	—	—	273
Cash dividends — Common stock ($.25 per share)	—	—	(143)	—	—	—	(143)
Allowance for and repayment of stockholders' notes	—	—	—	—	17	—	17
Stock award transactions, including tax benefit	4	60	—	—	—	—	64
Balance, December 31, 2005	579	6,328	(1,136)	(298)	(5)	(41)	5,427
Comprehensive income:							
Net income — 2006	—	—	309	—	—	—	309
Other comprehensive income:							
Net unrealized gains on cash flow hedges, net of reclassification adjustments	—	—	—	394	—	—	394
Foreign currency translation adjustments	—	—	—	(4)	—	—	(4)
Minimum pension liability adjustment	—	—	—	(1)	—	—	(1)
Total other comprehensive income							389
Total comprehensive income							698
Adjustment to initially apply SFAS No. 158, net of tax:							
Pension benefits:							
Prior service cost	—	—	—	(4)	—	—	(4)
Net actuarial loss	—	—	—	(150)	—	—	(150)
Minimum pension liability	—	—	—	5	—	—	5
Other postretirement benefits:							
Prior service cost	—	—	—	(4)	—	—	(4)
Net actuarial gain	—	—	—	2	—	—	2
Issuance of common stock from 5.5% debentures conversion (Note 12)	20	193	—	—	—	—	213
Cash dividends — Common stock ($.35 per share)	—	—	(207)	—	—	—	(207)
Repayment of stockholders' notes	—	—	—	—	5	—	5
Stock award transactions, including tax benefit	4	84	—	—	—	—	88
Balance, December 31, 2006	603	6,605	(1,034)	(60)	—	(41)	6,073
Comprehensive income:							
Net income — 2007	—	—	990	—	—	—	990
Other comprehensive loss:							
Net unrealized losses on cash flow hedges, net of reclassification adjustments	—	—	—	(177)	—	—	(177)
Foreign currency translation adjustments	—	—	—	53	—	—	53
Pension benefits:							
Net actuarial gain	—	—	—	53	—	—	53
Other postretirement benefits:							
Prior service cost	—	—	—	1	—	—	1
Net actuarial gain	—	—	—	9	—	—	9
Total other comprehensive loss							(61)
Total comprehensive income							929
Cash dividends — Common stock ($.39 per share)	—	—	(233)	—	—	—	(233)
FIN 48 adjustment (Note 5)	—	—	(17)	—	—	—	(17)
Purchase of treasury stock (Note 12)	—	—	—	—	—	(526)	(526)
Stock award transactions, including tax benefit	5	143	—	—	—	—	148
Other	—	—	1	—	—	—	1
Balance, December 31, 2007	$ 608	$ 6,748	$ (293)	$ (121)	$ —	$ (567)	$ 6,375

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
OPERATING ACTIVITIES:			
Net income	$ 990	$ 309	$ 314
Adjustments to reconcile to net cash provided by operations:			
Cumulative effect of change in accounting principle	—	—	2
Reclassification of deferred net hedge gains to earnings related to sale of power business	(429)	—	—
Depreciation, depletion and amortization	1,082	866	740
Provision (benefit) for deferred income taxes	370	154	(47)
Provision for loss on investments, property and other assets	162	26	119
Net (gain) loss on dispositions of assets and business	16	(23)	(59)
Early debt retirement costs	19	31	—
Minority interest in income of consolidated subsidiaries	90	40	26
Amortization of stock-based awards	70	44	13
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	(122)	386	(242)
Inventories	29	31	(10)
Margin deposits and customer margin deposits payable	(135)	98	86
Other current assets and deferred charges	(10)	(30)	(8)
Accounts payable	26	(184)	233
Accrued liabilities	(200)	(110)	27
Changes in current and noncurrent derivative assets and liabilities	370	303	174
Other, including changes in noncurrent assets and liabilities	(91)	(51)	82
Net cash provided by operating activities	2,237	1,890	1,450
FINANCING ACTIVITIES:			
Proceeds from long-term debt	684	1,299	—
Payments of long-term debt	(806)	(777)	(251)
Proceeds from issuance of common stock	56	34	310
Proceeds from sale of limited partner units of consolidated partnership	333	863	111
Tax benefit of stock-based awards	32	16	—
Dividends paid	(233)	(207)	(143)
Purchase of treasury stock	(526)	—	—
Payments for debt issuance costs and amendment fees	(4)	(37)	(30)
Premiums paid on early debt retirements and tender offer	(27)	(26)	—
Dividends and distributions paid to minority interests	(75)	(36)	(21)
Changes in cash overdrafts	52	(25)	63
Other — net	3	(1)	(3)
Net cash provided (used) by financing activities	(511)	1,103	36
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(2,816)	(2,509)	(1,299)
Net proceeds from dispositions	12	23	47
Proceeds from contract termination payment	—	3	88
Changes in accounts payable and accrued liabilities	(52)	105	65
Purchases of investments/advances to affiliates	(60)	(49)	(116)
Purchases of auction rate securities	(304)	(386)	(224)
Proceeds from sales of auction rate securities	353	414	138
Proceeds from sales of businesses	471	—	31
Proceeds from dispositions of investments and other assets	92	62	64
Proceeds received on sale of note from WilTel	—	—	55
Proceeds from Gulfstream recapitalization	—	—	310
Other — net	8	16	22
Net cash used by investing activities	(2,296)	(2,321)	(819)
Increase (decrease) in cash and cash equivalents	(570)	672	667
Cash and cash equivalents at beginning of year	2,269	1,597	930
Cash and cash equivalents at end of year	$ 1,699	$ 2,269	$ 1,597

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies

Description of Business

Operations of our company are located principally in the United States and are organized into the following reporting segments: Exploration & Production, Gas Pipeline, Midstream Gas & Liquids (Midstream), and Gas Marketing Services (Gas Marketing).

Exploration & Production includes natural gas development, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States and oil and natural gas interests in Argentina.

Gas Pipeline is comprised primarily of two interstate natural gas pipelines, as well as investments in natural gas pipeline-related companies. The Gas Pipeline operating segments have been aggregated for reporting purposes and include Northwest Pipeline GP (Northwest Pipeline), formerly Northwest Pipeline Corporation, which extends from the San Juan basin in northwestern New Mexico and southwestern Colorado to Oregon and Washington, and Transcontinental Gas Pipe Line Corporation (Transco), which extends from the Gulf of Mexico region to the northeastern United States. In addition, we own a 50 percent interest in Gulfstream Natural Gas System L.L.C. (Gulfstream). Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida.

Midstream is comprised of natural gas gathering and processing and treating facilities in the Rocky Mountain and Gulf Coast regions of the United States, oil gathering and transportation facilities in the Gulf Coast region of the United States, majority-owned natural gas compression facilities in Venezuela, and assets in Canada, consisting primarily of a natural gas liquids extraction facility and a fractionation plant.

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. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, and provides services to third parties, such as producers.

Basis of Presentation

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144), the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our power business as discontinued operations. (See Note 2.) These operations include a 7,500-megawatt portfolio of power-related contracts that were sold to Bear Energy, LP, a unit of The Bear Stearns Companies, Inc. and our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton), in addition to other power-related assets.

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

Williams Partners L.P. is a limited partnership engaged in the business of gathering, transporting and processing natural gas and fractionating and storing natural gas liquids. 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 segment.

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of our corporate parent and our majority-owned or controlled subsidiaries and investments. We apply the equity method of accounting for investments in unconsolidated companies in which we and our subsidiaries own 20 to 50 percent of the voting interest, or otherwise exercise significant influence over operating and financial policies of the company.

Use of estimates

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.

Significant estimates and assumptions include:

- Impairment assessments of investments, long-lived assets and goodwill;
- Litigation-related contingencies;
- Valuations of derivatives;
- Environmental remediation obligations;
- Hedge accounting correlations and probability;
- Realization of deferred income tax assets;
- Valuation of Exploration & Production’s reserves;
- Asset retirement obligations;
- Pension and postretirement valuation variables.

These estimates are discussed further throughout these notes.

Cash and cash equivalents

Cash and cash equivalents includes demand and time deposits, money market funds, and other marketable securities with maturities of three months or less when acquired.

Restricted cash

Restricted cash within *current assets* is included in *other current assets and deferred charges* in the Consolidated Balance Sheet and consists primarily of collateral required by certain loan agreements for our Venezuelan operations, and escrow accounts established to fund payments required by our California settlement. (See Note 15). Restricted cash within noncurrent assets is included in *other assets and deferred charges* in the Consolidated Balance Sheet and relates primarily to certain borrowings by our Venezuelan operations as previously mentioned and letters of credit. We do not expect this cash to be released within the next twelve months. The current and noncurrent restricted cash is primarily invested in short-term money market accounts with financial institutions.

The classification of restricted cash is determined based on the expected term of the collateral requirement and not necessarily the maturity date of the investment.

Auction rate securities

Auction rate securities are instruments with long-term underlying maturities, but for which an auction is conducted periodically, as specified, to reset the interest rate and allow investors to buy or sell the instruments. Because auctions generally occur more often than annually, and because we hold these investments in order to meet short-term liquidity needs, we classify auction rate securities as short-term and include them in *other current assets and deferred charges* on our Consolidated Balance Sheet. Our Consolidated Statement of Cash Flows reflects the gross amount of the *purchases of auction rate securities* and the *proceeds from sales of auction rate securities*.

Accounts receivable

Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Interest income related to past due accounts receivable is generally recognized at the time full payment is received or collectibility is assured. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted.

Inventory valuation

All *inventories* are stated at the lower of cost or market. We determine the cost of certain natural gas inventories held by Transco using the last-in, first-out (LIFO) cost method. We determine the cost of the remaining inventories primarily using the average-cost method.

Property, plant and equipment

Property, plant and equipment is recorded at cost. We base the carrying value of these assets on estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values.

As regulated entities, Northwest Pipeline and Transco provide for depreciation using the straight-line method at Federal Energy Regulatory Commission (FERC)-prescribed rates. Depreciation rates used for major regulated gas plant facilities for all years presented, are as follows:

Category of Property	Depreciation Rates
Gathering facilities	.01% - 3.8%
Storage facilities	.15% - 3.3%
Onshore transmission facilities	.15% - 7.25%
Offshore transmission facilities	.01% - 1.5%
General plant	2.95% - 50%

Depreciation for nonregulated entities is provided primarily on the straight-line method over estimated useful lives, except as noted below for oil and gas exploration and production activities. The estimated useful lives are as follows:

Category of Property	Estimated Useful Lives (In years)
Natural gas gathering and processing facilities	15 to 40
Transportation equipment	3 to 10
Building and improvements	5 to 45
Right of way	4 to 40
Office furnishings, computer software and hardware and other	3 to 30

Gains or losses from the ordinary sale or retirement of property, plant and equipment for regulated pipelines are credited or charged to accumulated depreciation; other gains or losses are recorded in *other (income) expense — net* included in *operating income*.

Ordinary maintenance and repair costs are generally expensed as incurred. Costs of major renewals and replacements are capitalized as *property, plant, and equipment — net*.

Oil and gas exploration and production activities are accounted for under the successful efforts method. Costs incurred in connection with the drilling and equipping of exploratory wells, as applicable, are capitalized as incurred. If proved reserves are not found, such costs are charged to expense. Other exploration costs, including lease rentals, are expensed as incurred. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred. *Depreciation, depletion and amortization* is provided under the units of production method on a field basis.

Unproved properties with individually significant acquisition costs are assessed annually, or as conditions warrant, and any impairment in value is recognized. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience or other information, is amortized over the average holding period. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties.

Proved properties, including developed and undeveloped, and costs associated with unproven reserves, are assessed for impairment using estimated future cash flows on a field basis. Estimating future cash flows involves the use of complex judgments such as estimation of the proved and unproven oil and gas reserve quantities, risk associated with the different categories of oil and gas reserves, timing of development and production, expected future commodity prices, capital expenditures, and production costs.

We record an asset and a liability upon incurrence equal to the present value of each expected future asset retirement obligation (ARO). The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense included in *other (income) expense — net* included in *operating income*, except for regulated entities, for which the liability is offset by a regulatory asset.

Goodwill

Goodwill represents the excess of cost over fair value of the assets of businesses acquired. It is evaluated annually for impairment by first comparing our management's estimate of the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess. We have *goodwill* of approximately $1 billion at December 31, 2007, and 2006, at our Exploration & Production segment.

When a reporting unit is sold or classified as held for sale, any goodwill of that reporting unit is included in its carrying value for purposes of determining any impairment or gain/loss on sale. If a portion of a reporting unit with goodwill is sold or classified as held for sale and that asset group represents a business, a portion of the reporting unit's goodwill is allocated to and included in the carrying value of that asset group. None of the operations sold during 2007 or 2005 represented reporting units with goodwill or businesses within reporting units to which goodwill was required to be allocated.

Judgments and assumptions are inherent in our management's estimate of undiscounted future cash flows used to determine the estimate of the reporting unit's fair value. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

Treasury stock

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock. Gains and losses on the subsequent reissuance of shares are credited or charged to *capital in excess of par value* using the average-cost method.

Derivative instruments and hedging activities

We utilize derivatives to manage our commodity price risk. These instruments consist primarily of futures contracts, swap agreements, option contracts, and forward contracts involving short- and long-term purchases and sales of a physical energy commodity. We execute most of these transactions on an organized commodity exchange or in over-the-counter markets in which quoted prices exist for active periods. For contracts with terms that exceed the time period for which actively quoted prices are available, we determine fair value by estimating commodity prices during the illiquid periods utilizing internally developed valuations incorporating information obtained from commodity prices in actively quoted markets, quoted prices in less active markets, prices reflected in current transactions, and other market fundamental analysis.

We report the fair value of derivatives, except for those for which the normal purchases and normal sales exception has been elected, on the Consolidated Balance Sheet in *derivative assets* and *derivative liabilities* as either current or noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual contracts.

The accounting for changes in the fair value of a commodity derivative is governed by SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” (SFAS No. 133), as amended and depends on whether the derivative has been designated in a hedging relationship and whether we have elected the normal purchases and normal sales exception. The accounting for the change in fair value can be summarized as follows:

Derivative Treatment	Accounting Method
Normal purchases and normal sales exception	Accrual accounting
Designated in a qualifying hedging relationship	Hedge accounting
All other derivatives	Mark-to-market accounting

We may elect the normal purchases and normal sales exception for certain short- and long-term purchases and sales of a physical energy commodity. Under accrual accounting, any change in the fair value of these derivatives is not reflected on the balance sheet after the initial election of the exception.

We have also designated a hedging relationship for certain commodity derivatives. For a derivative to qualify for designation in a hedging relationship, it must meet specific criteria and we must maintain appropriate documentation. We establish hedging relationships pursuant to our risk management policies. We evaluate the hedging relationships at the inception of the hedge and on an ongoing basis to determine whether the hedging relationship is, and is expected to remain, highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. We also regularly assess whether the hedged forecasted transaction is probable of occurring. If a derivative ceases to be or is no longer expected to be highly effective, or if we believe the likelihood of occurrence of the hedged forecasted transaction is no longer probable, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized currently in *revenues*.

For commodity derivatives designated as a cash flow hedge, the effective portion of the change in fair value of the derivative is reported in *other comprehensive income (loss)* and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative’s change in fair value is recognized currently in *revenues*. Gains or losses deferred in *accumulated other comprehensive loss* associated with terminated derivatives, derivatives that cease to be highly effective hedges, derivatives for which the forecasted transaction is reasonably possible but no longer probable of occurring, and cash flow hedges that have been otherwise discontinued remain in *accumulated other comprehensive loss* until the hedged item affects earnings. If it becomes probable that the forecasted transaction designated as the hedged item in a cash flow hedge will not occur, any gain or loss deferred in *accumulated other comprehensive loss* is recognized in *revenues* at that time. The change in likelihood is a judgmental decision that includes qualitative assessments made by management.

For commodity derivatives that are not designated in a hedging relationship, and for which we have not elected the normal purchases and normal sales exception, we report changes in fair value currently in *revenues*.

Certain gains and losses on derivative instruments included in the Consolidated Statement of Income are netted together to a single net gain or loss, while other gains and losses are reported on a gross basis. Gains and losses recorded on a net basis include:

- Unrealized gains and losses on all derivatives that are not designated as hedges and for which we have not elected the normal purchases and normal sales exception;
- The ineffective portion of unrealized gains and losses on derivatives that are designated as cash flow hedges;
- Realized gains and losses on all derivatives that settle financially;
- Realized gains and losses on derivatives held for trading purposes;
- Realized gains and losses on derivatives entered into as a pre-contemplated buy/sell arrangement.

Realized gains and losses on derivatives that require physical delivery, and which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we evaluated the indicators in EITF Issue No. 99-19 “Reporting Revenue Gross as a Principal versus as an Agent,” including whether we act as principal in the transaction; whether we have the risks and rewards of ownership, including credit risk; and whether we have latitude in establishing prices.

Gas Pipeline revenues

Revenues from the transportation of gas are recognized in the period the service is provided, and revenues for sales of products are recognized in the period of delivery. Gas Pipeline is subject to FERC regulations and, accordingly, certain revenues collected may be subject to possible refunds upon final orders in pending rate cases. Gas Pipeline records estimates of rate refund liabilities considering Gas Pipeline and other third-party regulatory proceedings, advice of counsel and estimated total exposure, as discounted and risk weighted, as well as collection and other risks.

Exploration & Production revenues

Revenues from the domestic production of natural gas in properties for which Exploration & Production has an interest with other producers are recognized based on the actual volumes sold during the period. Any differences between volumes sold and entitlement volumes, based on Exploration & Production’s net working interest, that are determined to be nonrecoverable through remaining production are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are not significant.

All other revenues

Revenues generally are recorded when services are performed or products have been delivered.

Impairment of long-lived assets and investments

We evaluate the long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our management's estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred. We apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes including selling in the near term or holding for the remaining estimated useful life. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

For assets identified to be disposed of in the future and considered held for sale in accordance with SFAS No. 144, we compare the carrying value to the estimated fair value less the cost to sell to determine if recognition of an impairment is required. Until the assets are disposed of, the estimated fair value, which includes estimated cash flows from operations until the assumed date of sale, is recalculated when related events or circumstances change.

We evaluate our investments for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such investments may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare our estimate of fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. If the estimated fair value is less than the carrying value and we consider the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in the consolidated financial statements as an impairment.

Judgments and assumptions are inherent in our management's estimate of undiscounted future cash flows and an asset's fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements.

Capitalization of interest

We capitalize interest during construction on major projects with construction periods of at least three months and a total project cost in excess of $1 million. Interest is capitalized on borrowed funds and, where regulation by the FERC exists, on internally generated funds as a component of *other income — net*. The rates used by regulated companies are calculated in accordance with FERC rules. Rates used by unregulated companies are based on the average interest rate on debt. The benefit of interest capitalized on internally generated funds for regulated entities is reported in *other income — net* below *operating income*.

Employee stock-based awards

Prior to January 1, 2006, we accounted for stock-based awards to employees and nonmanagement directors (see Note 13) under the recognition and measurement provisions of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations, as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123). Compensation cost for stock options was not recognized in the Consolidated Statement of Income for the years prior to 2006 as all options granted had an exercise price equal to the market value of the underlying common stock on the date of the grant. Prior to January 1, 2006, compensation cost was recognized for restricted stock units. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified-prospective method. Under this method, compensation cost recognized in periods subsequent to December 31, 2005, includes: (1) compensation cost for all share-based payments granted through December 31, 2005, but for which the requisite service period had not been completed as of December 31, 2005, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123, and (2) compensation cost for most share-based payments granted subsequent to December 31, 2005, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123(R). The performance targets for certain performance-based restricted stock units have not been established and therefore expense is not currently recognized. Expense associated with these performance-based awards will be recognized in future periods when performance targets are established. Results for prior periods have not been restated.

Total stock-based compensation expense for the years ending December 31, 2007 and 2006, was $70 million and $44 million, respectively, of which $9 million and $3 million, respectively, is included in *income (loss) from discontinued operations*. The 2006 amount reflects a reduction of $.3 million of previously recognized compensation cost for restricted stock units related to the estimated number of awards expected to be forfeited. This adjustment is not considered material for reporting as a cumulative effect of a change in accounting principle. Measured but unrecognized stock-based compensation expense at December 31, 2007, was approximately $62 million, which does not include the effect of estimated forfeitures of $3 million. This amount is comprised of approximately $7 million related to stock options and approximately $55 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.9 years.

The following table illustrates the effect on *net income* and *earnings per common share* for the year ending December 31, 2005, if we had applied the fair value recognition provisions of SFAS No. 123 to options granted. For purposes of this pro forma disclosure, the value of the options was estimated using a Black-Scholes option pricing model and amortized to expense over the vesting period of the options.

	Year Ended December 31, 2005 (Dollars in millions, except per share amounts)
Net income, as reported	$ 314
Add: Stock-based employee compensation expense included in the consolidated statement of income, net of related tax effects	9
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(17)
Pro forma net income	$ 306
Earnings per common share:	
Basic — as reported	$ .55
Basic — pro forma	$ .54
Diluted — as reported	$ .53
Diluted — pro forma	$ .52

Pro forma amounts for 2005 include compensation expense from awards of our company stock made in 2005, 2004, 2003, and 2002.

Income taxes

We include the operations of our subsidiaries in our consolidated tax return. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of our assets and liabilities. Our management's judgment and income tax assumptions are used to determine the levels, if any, of valuation allowances associated with deferred tax assets.

Earnings (loss) per common share

Basic earnings (loss) per common share is based on the sum of the weighted-average number of common shares outstanding and issuable restricted stock units. *Diluted earnings (loss) per common share* includes any dilutive effect of stock options, nonvested restricted stock units and, for applicable periods presented, convertible debt, unless otherwise noted.

Foreign currency translation

Certain of our foreign subsidiaries and equity method investees use their local currency as their functional currency. These foreign currencies include the Canadian dollar, British pound and Euro. Assets and liabilities of certain foreign subsidiaries and equity investees are translated at the spot rate in effect at the applicable reporting date, and the combined statements of operations and our share of the results of operations of our equity affiliates are translated into the U.S. dollar at the average exchange rates in effect during the applicable period. The resulting cumulative translation adjustment is recorded as a separate component of *other comprehensive income (loss)*.

Transactions denominated in currencies other than the functional currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates result in transaction gains and losses which are reflected in the Consolidated Statement of Income.

Issuance of equity of consolidated subsidiary

Sales of residual equity interests in a consolidated subsidiary are accounted for as capital transactions. No adjustments to capital are made for sales of preferential interests in a subsidiary. No gain or loss is recognized on these transactions.

Recent Accounting Standards

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). This Statement establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, permitting entities to delay application of SFAS No. 157 to fiscal years beginning after November 15, 2008 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). SFAS No. 157 requires two distinct transition approaches; (i) cumulative-effect adjustment to beginning retained earnings for certain financial instrument transactions and (ii) prospectively as of the date of adoption through earnings or other comprehensive income, as applicable. On January 1, 2008, we partially applied SFAS No. 157 through a prospective transition for our assets and liabilities that are measured at fair value on a recurring basis, primarily our commodity derivatives, with no material impact to our Consolidated Financial Statements. We did not have financial instrument transactions that required a cumulative-effect adjustment to beginning retained earnings upon the adoption of SFAS No. 157. Beginning January 1, 2009, we will apply SFAS No. 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed on a recurring basis. SFAS No. 157 expands disclosures about assets and liabilities measured at fair value on a recurring basis effective beginning with first-quarter 2008 reporting.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). SFAS No. 159 establishes a fair value option permitting entities to elect to measure eligible financial instruments and certain other items at fair value. Unrealized gains and losses on items for which the fair value option has been elected will be reported in earnings. The fair value option may be applied on an instrument-by-instrument basis, is irrevocable and is applied to the entire instrument. SFAS No. 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007, and should not be applied retrospectively to fiscal years beginning prior to the effective date. On the adoption date, an entity may elect the fair value option for eligible items existing at that date and the adjustment for the initial remeasurement of those items to fair value should be reported as a cumulative effect adjustment to the opening balance of retained earnings. Subsequent to January 1, 2008, the fair value option can only be elected when a financial instrument or certain other item is entered into. On January 1, 2008, we did not elect the fair value option for any existing eligible financial instruments or certain other items.

In April 2007, the FASB issued an FSP on a previously issued FASB Interpretation (FIN), FSP FIN 39-1, "Amendment of FASB Interpretation No. 39." FSP FIN 39-1 amends FIN 39, "Offsetting of Amounts Related to Certain Contracts (as amended)" by requiring the offsetting of fair value amounts recognized for the right to reclaim or obligation to return cash collateral if the related derivative instruments have been offset pursuant to a master netting arrangement. The FSP requires disclosure of the accounting policy related to offsetting fair value amounts pursuant to master netting arrangements as well as disclosure of amounts recognized for the right to reclaim or obligation to return cash collateral. This FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted, and is applied retrospectively as a change in accounting principle for all financial statements presented. We do not offset derivative instruments subject to master netting arrangements for financial statement presentation purposes; therefore, there is no change to our accounting policy and no financial impact on our Consolidated Financial Statements.

In June 2007, the FASB ratified EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11). EITF 06-11 requires that the income tax benefits received on dividends or dividend equivalents paid to employees holding equity-classified nonvested shares be recorded as additional paid-in capital when the dividends or dividend equivalents are charged to retained earnings pursuant to SFAS No. 123(R). This EITF is applied prospectively and is effective for fiscal years beginning after December 15, 2007, and interim periods within those years. EITF 06-11 requires the disclosure of any change in accounting policy for income tax benefits of dividends or dividend equivalents on share-based payment awards as a result of adoption. We began applying the provisions of EITF 06-11 on January 1, 2008 with no material impact on our Consolidated Financial Statements.

In December 2007, the FASB issued SFAS No. 141(R) "Business Combinations" (SFAS No. 141(R)). SFAS No. 141(R) applies to all business combinations and establishes guidance for recognizing and measuring identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree and goodwill. Most of these items are recognized at their full fair value on the acquisition date, including acquisitions where the acquirer obtains control but less than 100 percent ownership in the acquiree. SFAS No. 141(R) also requires expensing of transaction costs as incurred and establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. SFAS No. 141(R) is effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008.

In December 2007, the FASB issued SFAS No. 160 "Noncontrolling Interests in Consolidated Financial Statements — an amendment of Accounting Research Bulletin No. 51" (SFAS No. 160). SFAS No. 160 establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries (previously referred to as minority interests). Noncontrolling ownership interests in consolidated subsidiaries will be presented in the consolidated balance sheet within stockholders' equity as a separate component from the parent's equity. Earnings attributable to the noncontrolling interests will be reported as a part of consolidated net income and not as a separate income or expense item. Earnings per share will continue to be based on earnings attributable to only the parent company and does not change upon adoption of SFAS No. 160. SFAS No. 160 provides guidance on accounting for changes in the parent's ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished. SFAS No. 160 also requires additional disclosure of information related to noncontrolling interests. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008, and early adoption is prohibited. The Statement will be applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of the fiscal year it is initially adopted. However, the presentation of noncontrolling interests within stockholders' equity and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented. We will assess the impact on our Consolidated Financial Statements.

Note 2. Discontinued Operations

The businesses discussed below represent components that have been sold or approved for sale by our Board of Directors and are classified as discontinued operations. Therefore, their results of operations (including any impairments, gains or losses) and financial position have been reflected in the consolidated financial statements and notes as discontinued operations.

In November, 2007, we completed the sale of substantially all of our power business to Bear Energy, LP, a unit of The Bear Stearns Companies, Inc., for approximately $496 million in cash, subject to the final purchase price adjustments. Included in the sale was our portfolio of power-related contracts, which consisted of tolling contracts, full requirement contracts, tolling resales, heat rate options, related hedges and other related assets.

Summarized Results of Discontinued Operations

The following table presents the summarized results of discontinued operations for the years ended December 31, 2007, 2006, and 2005.

	2007	2006 (Millions)	2005
Revenues	$ 2,436	$ 2,437	$ 2,802
Income (loss) from discontinued operations before income taxes	$ 392	$ (58)	$ (247)
(Impairments) and gain (loss) on sales	(162)	—	1
Benefit (provision) for income taxes	(87)	20	89
Income (loss) from discontinued operations	$ 143	$ (38)	$ (157)

Income (loss) from discontinued operations before income taxes for the year ended December 31, 2007, includes a gain of $429 million (reported in *revenues* of discontinued operations) associated with the reclassification of deferred net hedge gains from *accumulated other comprehensive income* to earnings in second-quarter 2007. This reclassification was based on the determination that the forecasted transactions related to the derivative cash flow hedges being sold to Bear Energy, LP, were probable of not occurring. This gain is partially offset by current year unrealized mark-to-market losses of approximately $23 million. *Income (loss) from discontinued operations before income taxes* for the year ended December 31, 2006, includes charges of $19 million for an adverse arbitration award related to our former chemical fertilizer business, $6 million for a loss contingency in connection with a former exploration business, and $15 million associated with an oil purchase contract related to our former Alaska refinery. In addition, we recorded income of $13 million related to the reduction of contingent obligations associated with our former distributive power business. *Income (loss) from discontinued operations before income taxes* includes the results of our former power business operations in each year.

(Impairments) and gain (loss) on sales for the year ended December 31, 2007, includes a pre-tax loss on the sale of substantially all of our power business of approximately $37 million. We have also recognized impairments of approximately $111 million related to the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception under SFAS No. 133, and, accordingly, were no longer recording at fair value, and approximately $14 million related to our natural gas-fired electric generating

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plant near Hazelton, Pennsylvania (Hazleton). These impairments were based on our comparison of the carrying value to the estimate of fair value less cost to sell.

Summarized Assets and Liabilities of Discontinued Operations

The following table presents the summarized assets and liabilities of discontinued operations as of December 31, 2007 and 2006.

The December 31, 2007, balances for *derivative assets* and *derivative liabilities* represent contracts remaining to be assigned to Bear Energy, LP, entirely offset by reciprocal positions with Bear Energy, LP. We expect to complete the assignment of all such contracts in 2008. The December 31, 2007, balance of *property, plant and equipment — net* includes Hazelton, which is under contract to be sold.

	December 31, 2007	December 31, 2006
	(Millions)	
Derivative assets	$ 114	$ 593
Accounts receivable — net	55	232
Other current assets	3	12
Total current assets	172	837
Property, plant and equipment — net	8	23
Derivative assets	—	541
Other noncurrent assets	5	1
Total noncurrent assets	13	565
Total assets	$ 185	$ 1,402
Reflected on balance sheet as:		
Current assets	$ 185	$ 837
Noncurrent assets	—	565
Total assets	$ 185	$ 1,402
Derivative liabilities	$ 114	$ 479
Other current liabilities	61	260
Total current liabilities	175	739
Derivative liabilities	—	124
Other noncurrent liabilities	—	23
Total noncurrent liabilities	—	147
Total liabilities	$ 175	$ 886
Reflected on balance sheet as:		
Current liabilities	$ 175	$ 739
Noncurrent liabilities	—	147
Total liabilities	$ 175	$ 886

Note 3. Investing Activities

Investing Income

Investing income for the years ended December 31, 2007, 2006 and 2005, is as follows:

	2007	2006	2005
		(Millions)	
Equity earnings*	$ 137	$ 99	$ 66
Loss from investments*	—	—	(109)
Impairments of cost-based investments	(1)	(20)	(2)
Interest income and other	121	89	70
Total	$ 257	$ 168	$ 25

* Items also included in *segment profit*. (See Note 17.)

Loss from investments for the year ended December 31, 2005, includes:

- An $87 million impairment of our investment in Longhorn Partners Pipeline L.P. (Longhorn), which is included in our Other segment;
- A $23 million impairment of our investment in Aux Sable Liquid Products, L.P. (Aux Sable), which is included in our Midstream segment.

Impairments of cost-based investments for the year ended December 31, 2006, includes a $16 million impairment of a Venezuelan investment primarily due to a decline in reserve estimates. In 2006, our 10 percent direct working interest in an operating contract was converted to a 4 percent equity interest in a Venezuelan corporation which owns and operates oil and gas activities. Our 4 percent equity interest is reported as a cost method investment; previously, we accounted for our working interest using the proportionate consolidation method.

Interest income and other for the year ended December 31, 2007, includes $14 million of gains from sales of cost-based investments.

Investments

Investments at December 31, 2007 and 2006, are as follows:

	2007	2006
	(Millions)	
Equity method:		
Gulfstream Natural Gas System, L.L.C. — 50%	$ 439	$ 387
Discovery Producer Services, L.L.C. — 60%*	215	221
Petrolera Entre Lomas S.A. — 40.8%	65	59
ACCROVEN — 49.3%	62	57
Other	95	90
	876	814
Cost method	25	52
	$ 901	$ 866

* We own 60 percent indirectly through Williams Partners L.P., of which we own approximately 23.6 percent. We continue to account for this investment under the equity method due to the voting provisions of Discovery's limited liability company which provide the other member of Discovery significant participatory rights such that we do not control the investment.

Differences between the carrying value of our equity investments and the underlying equity in the net assets of the investees is primarily related to impairments previously recognized.

Dividends and distributions, including those presented below, received from companies accounted for by the equity method were $118 million in 2007 and $116 million in 2006. These transactions reduced the carrying value of our investments. These dividends and distributions primarily included:

	2007	2006
	(Millions)	
Discovery Producer Services, L.L.C.	$ 36	$ 27
Gulfstream Natural Gas System L.L.C.	34	42
Aux Sable Liquid Products L.P.	22	13
Petrolera Entre Lomas S.A.	12	14

In addition in 2007, we contributed $38 million to Gulfstream Natural Gas System L.L.C. (Gulfstream).

Summarized Financial Position and Results of Operations of Equity Method Investments

Financial position at December 31:

	2007	2006
	(Millions)	
Current assets	$ 395	$ 296
Noncurrent assets	3,482	3,302
Current liabilities	232	198
Noncurrent liabilities	1,483	1,311

Results of operations for the years ended December 31:

	2007	2006	2005
		(Millions)	
Gross revenue	$ 1,183	$ 970	$ 1,338
Operating income	533	401	236
Net income (loss)	392	(15)	105

Summarized results of operations of equity method investments in 2006 reflect the impact of a loss incurred by Longhorn on the sale of its pipeline.

Guarantees on Behalf of Investees

We have guaranteed commercial letters of credit totaling $20 million on behalf of ACCROVEN. These expire in January 2009 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 December 31, 2007 and 2006.

Note 4. Asset Sales and Other Accruals

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

	Years Ended December 31,		
	2007	2006 (Millions)	2005
Exploration & Production			
Gains on sales of certain natural gas properties	$ —	$ —	$ (30)
Gas Pipeline			
Change in estimate related to a regulatory liability	(17)	—	—
Income associated with payments received for a terminated firm transportation agreement on Grays Harbor lateral. Associated with this gain is interest income of $2 million, which is included in *investing income*	(18)	—	—
Midstream			
Income from favorable litigation outcome	(12)	—	—
Loss on impairment of Carbonate Trend pipeline	10	—	—
Accrual for Gulf Liquids litigation contingency. Associated with this contingency is an interest expense accrual of $25 million, which is included in *interest accrued* (see Note 15)	—	73	—
Gas Marketing Services			
Accrual for litigation contingencies	20	—	82

Additional Items

Costs and operating expenses within our Gas Pipeline segment reported in 2005 includes:

- An adjustment to reduce costs by $12 million to correct the carrying value of certain liabilities recorded in prior periods;
- Adjustments of $37 million reflected as increases in costs and operating expenses related to $32 million of prior period accounting and valuation corrections for certain inventory items and an accrual of $5 million for contingent refund obligations.

Selling, general and administrative expenses within our Gas Pipeline segment in 2005 includes:

- An adjustment to reduce costs by $6 million to correct the carrying value of certain liabilities recorded in prior periods;
- A $17 million reduction in pension expense for the cumulative impact of a correction of an error attributable to 2003 and 2004. (See Note 7.)

Note 5. Provision for Income Taxes

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

	2007	2006 (Millions)	2005
Current:			
Federal	$ 29	$ (9)	$ 225
State	9	3	3
Foreign	46	43	31
	84	37	259
Deferred:			
Federal	422	146	23
State	(4)	4	27
Foreign	22	24	(8)
	440	174	42
Total provision	$ 524	$ 211	$ 301

Reconciliations from the *provision for income taxes* from continuing operations at the federal statutory rate to the realized *provision for income taxes* are as follows:

	2007	2006 (Millions)	2005
Provision at statutory rate	$ 480	$ 195	$ 271
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	4	7	29
Foreign operations — net	18	23	2
Utilization/valuation/expiration of charitable contributions	(6)	(9)	8
Federal income tax litigation	—	(40)	4
Non-deductible convertible debenture expenses	—	10	—
Adjustment of excess deferred taxes	2	7	(20)
Non-deductible penalties	—	—	18
Other — net	26	18	(11)
Provision for income taxes	$ 524	$ 211	$ 301

Utilization of foreign operating loss carryovers reduced the provision for income taxes by $5 million, $3 million and $13 million in 2007, 2006 and 2005, respectively.

Income from continuing operations before income taxes and cumulative effect of change in accounting principle includes $169 million, $144 million, and $72 million of international income in 2007, 2006, and 2005, respectively.

We provide for income taxes using the asset and liability method as required by SFAS No. 109, "Accounting for Income Taxes." As a result of additional analysis of our tax basis and book basis assets and liabilities, we recorded a tax provision of $2 million and $7 million for 2007 and 2006, respectively, and a tax benefit of $20 million in 2005, to adjust the overall deferred income tax liabilities on the Consolidated Balance Sheet.

During the course of audits of our business by domestic and foreign tax authorities, we frequently face challenges regarding the amount of taxes due. These challenges include questions regarding the timing and amount of deductions and the allocation of income among various tax jurisdictions. In evaluating the liability associated with our various tax filing positions, we apply the two-step process of recognition and measurement as required by FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" (FIN 48). In association with this liability, we record an estimate of related interest and tax exposure as a component of our tax provision. The impact of this accrual is included within *other — net* in our reconciliation of the tax provision to the federal statutory rate.

Significant components of *deferred tax liabilities* and *deferred tax assets* as of December 31, 2007, and 2006, are as follows:

	2007	2006
	(Millions)	
Deferred tax liabilities:		
Property, plant and equipment	$ 3,192	$ 2,899
Derivatives — net	—	223
Investments	176	210
Other	89	101
Total deferred tax liabilities	3,457	3,433
Deferred tax assets:		
Minimum tax credits	8	146
Accrued liabilities	433	510
Derivatives — net	173	—
Federal carryovers	—	183
Foreign carryovers	50	36
Other	53	51
Total deferred tax assets	717	926
Less valuation allowance	57	36
Net deferred tax assets	660	890
Overall net deferred tax liabilities	$ 2,797	$ 2,543

The *valuation allowance* at December 31, 2007 and December 31, 2006, serves to reduce the recognized tax benefit associated with foreign carryovers to an amount that will, more likely than not, be realized. We do not expect to be able to utilize our $57 million foreign deferred tax assets primarily related to carryovers.

Undistributed earnings of certain consolidated foreign subsidiaries at December 31, 2007, totaled approximately $262 million. No provision for deferred U.S. income taxes has been made for these subsidiaries because we intend to permanently reinvest such earnings in foreign operations.

Cash payments for income taxes (net of refunds) were $384 million, $79 million, and $230 million in 2007, 2006, and 2005, respectively. Cash tax payments include settlements with taxing authorities associated with prior period audits of $94 million, $42 million, and $204 million in 2007, 2006 and 2005, respectively.

Effective January 1, 2007, we adopted FIN 48 and, as required by the Interpretation, recognized the net impact of the cumulative effect of adoption as a $17 million increase to *accumulated deficit*. The Interpretation prescribes guidance for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. To recognize a tax position, the enterprise determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. A tax position that meets the more likely than not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured as the largest amount of benefit, determined on a cumulative probability basis, that is greater than 50 percent likely of being realized upon ultimate settlement.

As of December 31, 2007, we had approximately $76 million of unrecognized tax benefits. If recognized, approximately $64 million, net of federal tax expense, would be recorded as a reduction of income tax expense. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	(Millions)
Balance at January 1, 2007	$ 93
Additions based on tax positions related to the current year	—
Additions for tax positions for prior years	5
Reductions for tax positions of prior years	(19)
Settlement with taxing authorities	(3)
Lapse of applicable statute of limitations	—
Balance at December 31, 2007	$ 76

We recognize related interest and penalties as a component of income tax expense. During 2007, approximately $60 million of interest and penalties were included in the provision for income taxes. As of December 31, 2007, approximately $86 million of interest and penalties primarily relating to uncertain tax positions have been accrued.

As of December 31, 2007, the Internal Revenue Service (IRS) examination of our consolidated U.S. income tax return for 2002 through 2005 was in process. IRS examinations for 1996 through 2001 have been completed but the years remain open while certain issues are under review with the Appeals Division of the IRS. The statute of limitations for most states expires one year after IRS audit settlement.

Generally, tax returns for our Venezuela and Canadian entities are open to audit from 2003 through 2007. Tax returns for our Argentine entities are open to audit from 2001 through 2007. Certain Canadian entities are currently under examination.

During the next twelve months, we do not expect settlement of any unrecognized tax benefit associated with domestic or international matters under audit to have a material impact on our financial position.

Note 6. Earnings Per Common Share from Continuing Operations

Basic and diluted earnings per common share for the years ended December 31, 2007, 2006 and 2005, are:

	2007	2006	2005
	(Dollars in millions, except per-share amounts; shares in thousands)		
Income from continuing operations available to common stockholders for basic and diluted earnings per share(1)	$ 847	$ 347	$ 473
Basic weighted-average shares(2)	596,174	595,053	570,420
Effect of dilutive securities:			
Nonvested restricted stock units(3)	1,627	1,029	2,890
Stock options	4,743	4,440	4,989
Convertible debentures	7,322	8,105	27,548
Diluted weighted-average shares	609,866	608,627	605,847
Earnings per common share from continuing operations:			
Basic	$ 1.42	$ .58	$ .82
Diluted	$ 1.40	$ .57	$ .79

(1) The years ended December 31, 2007, 2006 and 2005, include $3 million, $3 million and $10 million of interest expense, net of tax, associated with our convertible debentures. (See Note 12.) These amounts have been added back to *income from continuing operations available to common stockholders* to calculate diluted earnings per common share.

(2) During January 2006, we issued 20 million shares of common stock related to a conversion offer for our 5.5 percent convertible debentures. In February 2005, we issued 11 million common shares associated with our FELINE PACS units.

(3) The nonvested restricted stock units outstanding at December 31, 2007, will vest over the period from January 2008 to January 2012.

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

	2007	2006	2005
Options excluded (millions)	.8	3.6	4.7
Weighted-average exercise prices of options excluded	$40.07	$36.14	$35.22
Exercise price ranges of options excluded	$36.66 - $42.29	$26.79 - $42.29	$22.68 - $42.29
Fourth quarter weighted-average market price	$35.14	$25.77	$22.41

Note 7. Employee Benefit Plans

We have noncontributory defined benefit pension plans in which all eligible employees participate. Currently, eligible employees earn benefits primarily based on a cash balance formula. Various other formulas, as defined in the plan documents, are utilized to calculate the retirement benefits for plan participants not covered by the cash balance formula. At the time of retirement, participants may receive annuity payments, a lump sum payment or a combination of lump sum and annuity payments. In addition to our pension plans, we currently provide subsidized medical and life insurance benefits (other postretirement benefits) to certain eligible participants. Generally, employees hired after December 31, 1991, are not eligible for the subsidized medical benefits, except for participants that were employees of Transco Energy Company on December 31, 1995, and other miscellaneous defined participant groups. Certain of these other postretirement benefit plans, particularly the subsidized medical benefit plans, provide for retiree contributions and contain other cost-sharing features such as deductibles, co-payments, and co-insurance. The accounting for these plans anticipates future cost-sharing that is consistent with our expressed intent to increase the retiree contribution level generally in line with health care cost increases.

Benefit Obligations

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years indicated. The annual measurement date for our plans is December 31. The sale of our power business did not have a significant impact on our employee benefit plans. (See Note 2.)

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
		(Millions)		
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 931	$ 897	$ 312	$ 375
Service cost	23	22	3	3
Interest cost	54	51	17	17
Plan participants' contributions	—	—	5	5
Benefits paid	(64)	(52)	(23)	(24)
Actuarial (gain) loss	(48)	13	(30)	(64)
Benefit obligation at end of year	896	931	284	312
Change in plan assets:				
Fair value of plan assets at beginning of year	1,005	888	180	164
Actual return on plan assets	92	126	15	21
Employer contributions	41	43	15	14
Plan participants' contributions	—	—	5	5
Benefits paid	(64)	(52)	(23)	(24)
Fair value of plan assets at end of year	1,074	1,005	192	180
Funded status — overfunded (underfunded)	$ 178	$ 74	$ (92)	$ (132)
Accumulated benefit obligation	$ 838	$ 872		

The net underfunded/overfunded status of our pension plans and other postretirement benefit plans presented in the previous table are recognized in the Consolidated Balance Sheet within the following accounts:

	December 31, 2007	December 31, 2006
	(Millions)	
Overfunded pension plans:		
Noncurrent assets	$ 203	$ 114
Underfunded pension plans:		
Current liabilities	1	1
Noncurrent liabilities	24	39
Underfunded other postretirement benefit plans:		
Current liabilities	9	9
Noncurrent liabilities	83	123

The plan assets within our other postretirement benefit plans are intended to be used for the payment of benefits for certain groups of participants. The *current liabilities* for the other postretirement benefit plans represent the actuarial present value of benefits included in the benefit obligation payable in the subsequent year for the groups of participants whose benefits are not expected to be paid from plan assets.

The 2007 *actuarial gain* of $48 million for our pension plans included in the table of changes in benefit obligation is due primarily to the impact of changes in the discount rate assumptions utilized to calculate the benefit obligation. The 2006 *actuarial loss* of $13 million for our pension plans included in the table of changes in benefit obligation is due primarily to the impact of actual results differing from assumed results such as compensation and participant deaths, offset by the net impact of changes in assumptions utilized to calculate the benefit obligation including the discount rate, mortality and expected form of benefit payments. The 2007 *actuarial gain* of $30 million for our other postretirement benefit plans included in the table of changes in benefit obligation is due primarily to the impact of the increase in the discount rate used to calculate the benefit obligation and a decrease in the number of eligible participants in the plan. The 2006 *actuarial gain* of $64 million for our other postretirement benefit plans included in the table of changes in benefit obligation is due primarily to the impact of changes in assumptions utilized to calculate the benefit obligation including claims costs, health care cost trend rates and the discount rate, as well as actual results differing from assumed results such as participant deaths and terminations prior to retirement.

The current accounting rules for the determination of *net periodic benefit expense* allow for the delayed recognition of gains and losses caused by differences between actual and assumed outcomes for items such as estimated return on plan assets, or caused by changes in assumptions for items such as discount rates or estimated future compensation levels. The *net actuarial gains (losses)* presented in the following table and recorded in *accumulated other comprehensive loss* and *net regulatory liabilities* represents the cumulative net deferred gains (losses) from these types of differences or changes which have not yet been recognized in the Consolidated Statement of Income. A portion of the *net actuarial gains (losses)* are amortized over the participants' average remaining future years of service, which is approximately 12 years for both our pension plans and our other postretirement benefit plans.

Accumulated other comprehensive loss at December 31 includes the following:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
	(Millions)			
Amounts not yet recognized in net periodic benefit expense:				
Prior service cost	$ (6)	$ (6)	$ (5)	$ (7)
Net actuarial gains (losses)	(156)	(242)	7	(8)

At December 31, 2007, *net regulatory liabilities* includes prior service credits of $3 million and net actuarial gains of $26 million for our other postretirement benefit plans associated with our FERC-regulated gas pipelines. These amounts have not yet been recognized in *net periodic benefit expense.* At December 31, 2006, prior service credits of $5 million and net actuarial gains of $8 million were included in *net regulatory liabilities*.

We have multiple pension plans that are aggregated as prescribed for reporting purposes including both overfunded and underfunded pension plans.

Information for pension plans with a projected benefit obligation in excess of plan assets:

	December 31,	
	2007	2006
	(Millions)	
Projected benefit obligation	$ 25	$ 480
Fair value of plan assets	—	440

At December 31, 2007, the pension plans with a projected benefit obligation in excess of plan assets includes only our unfunded nonqualified pension plans. At December 31, 2006, the pension plans with a projected benefit obligation in excess of plan assets included one of our funded tax-qualified pension plans and our unfunded nonqualified pension plans.

Information for pension plans with an accumulated benefit obligation in excess of plan assets:

	December 31,	
	2007	2006
	(Millions)	
Accumulated benefit obligation	$ 22	$ 19
Fair value of plan assets	—	—

Net Periodic Benefit Expense (Income) and Items Recognized in Other Comprehensive Income (Loss)

Net periodic benefit expense (income) and other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss)* for the years ended December 31, 2007, 2006, and 2005, consist of the following:

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
	(Millions)					
Components of net periodic benefit expense (income):						
Service cost	$ 23	$ 22	$ 21	$ 3	$ 3	$ 3
Interest cost	54	51	47	17	17	20
Expected return on plan assets	(73)	(67)	(71)	(12)	(11)	(11)
Amortization of prior service credit	—	(1)	—	—	—	(4)
Amortization of net actuarial (gain) loss	19	21	(5)	—	—	3
Regulatory asset amortization	1	—	1	5	7	7
Settlement/curtailment expense	—	—	3	—	—	—
Net periodic benefit expense (income)	$ 24	$ 26	$ (4)	$ 13	$ 16	$ 18
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss):*						
Net actuarial gain	$ (68)			$ (15)		
Amortization of net actuarial losses	(19)			—		
Amortization of prior service costs	—			(2)		
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss)*	(87)			(17)		
Total recognized in *net periodic benefit expense* and *other comprehensive income (loss)*	$ (63)			$ (4)		

Other changes in plan assets and benefit obligations for our other postretirement benefit plans associated with our FERC-regulated gas pipelines are recognized in *net regulatory liabilities* at December 31, 2007, and include *net actuarial gains* of $18 million and *amortization of prior service credits* of $2 million.

Net actuarial losses of $8 million and prior service costs of $1 million related to our pension plans that are included in *accumulated other comprehensive loss* at December 31, 2007, are expected to be amortized in *net periodic benefit expense* in 2008. Prior service costs of $1 million related to our other postretirement benefit plans that are included in *accumulated other comprehensive loss* at December 31, 2007, are expected to be amortized in *net periodic benefit expense* in 2008. No net actuarial losses related to our other postretirement benefit plans that are included in *accumulated other comprehensive loss* at December 31, 2007, are expected to be amortized in *net periodic benefit expense* in 2008.

The prior service credit related to our other postretirement benefit plans that is included in *net regulatory liabilities* at December 31, 2007, and expected to be recognized in *net periodic benefit expense (income)* in 2008 is $1 million. No net actuarial gains related to our other postretirement benefit plans and included in *net regulatory liabilities* are expected to be recognized in *net periodic benefit expense* in 2008.

Net periodic benefit expense (income) for our pension plans for 2005 includes a $17 million reduction to expense to record the cumulative impact of a correction of an error determined to have occurred in 2003 and 2004.

The error was associated with the actuarial computation of annual *net periodic benefit expense (income)* which resulted from the identification of errors in certain Transco participant data involving annuity contract information utilized for 2003 and 2004. The adjustment is reflected as $16 million within *amortization of net actuarial (gain) loss* and $1 million within *regulatory asset amortization.*

The differences in the amount of actuarially determined *net periodic benefit expense* for our other postretirement benefit plans and the other postretirement benefit costs recovered in rates for our FERC-regulated gas pipelines are deferred as a regulatory asset or liability. At December 31, 2007, we have regulatory liabilities of $10 million for Transco and $18 million for Northwest Pipeline related to these deferrals. At December 31, 2006, we had a regulatory asset of $9 million for Transco and a regulatory liability of $13 million at Northwest Pipeline related to these deferrals. These amounts will be reflected in future rates based on Transco and Northwest Pipeline's rate structures.

Key Assumptions

The weighted-average assumptions utilized to determine benefit obligations as of December 31, 2007, and 2006, are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
Discount rate	6.41%	5.80%	6.40%	5.80%
Rate of compensation increase	5.00	5.00	N/A	N/A

The weighted-average assumptions utilized to determine *net periodic benefit expense* for the years ended December 31, 2007, 2006, and 2005, are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
Discount rate	5.80%	5.65%	5.86%	5.80%	5.60%	5.63%
Expected long-term rate of return on plan assets	7.75	7.75	8.50	6.97	6.95	7.45
Rate of compensation increase	5.00	5.00	5.00	N/A	N/A	N/A

The discount rates for our pension and other postretirement benefit plans were determined separately based on an approach specific to our plans and their respective expected benefit cash flows. The plans were analyzed and the year-end discount rates were determined based on a yield curve comprised of high-quality corporate bonds published by a large securities firm.

The expected long-term rates of return on plan assets were determined by combining a review of the historical returns realized within the portfolio, the investment strategy included in the plans' Investment Policy Statement, and capital market projections for the asset classifications in which the portfolio is invested and the target weightings of each asset classification.

The mortality assumptions used to determine the obligations for our pension and other postretirement benefit plans are related to the experience of the plans and the best estimate of expected plan mortality. The selected mortality tables are among the most recent tables available.

The assumed health care cost trend rate for 2008 is 9.6 percent, and systematically decreases to 5.4 percent by 2015. The health care cost trend rate assumption has a significant effect on the amounts reported. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	Point increase	Point decrease
	(Millions)	
Effect on total of service and interest cost components	$ 3	$ (4)
Effect on other postretirement benefit obligation	55	(44)

Plan Assets

The investment policy for our pension and other postretirement benefit plans articulates an investment philosophy in accordance with ERISA which governs the investment of the assets in a diversified portfolio. The investment strategy for the assets of the pension plans and approximately one half of the assets of the other postretirement benefit plans include maximizing returns with reasonable and prudent levels of risk. The investment returns on the approximate one half of remaining assets of the other postretirement benefit plans is subject to federal income tax, therefore the investment strategy also includes investing in a tax efficient manner.

The following table presents the weighted-average asset allocations at December 31, 2007, and 2006 and target asset allocation at December 31, 2007, by asset category.

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	Target	2007	2006	Target
Equity securities	84%	82%	84%	79%	77%	80%
Debt securities	12	12	16	12	12	20
Other	4	6	—	9	11	—
	100%	100%	100%	100%	100%	100%

Included in equity securities are investments in commingled funds that invest entirely in equity securities and comprise 40 percent at December 31, 2007, and 38 percent at December 31, 2006, of the pension plans' weighted-average assets, and 29 percent at December 31, 2007, and 27 percent at December 31, 2006, of the other postretirement benefit plans' weighted-average assets. Other assets are comprised primarily of cash and cash equivalents.

The assets are invested in accordance with the target allocations identified in the previous table. The investment policy provides for minimum and maximum ranges for the broad asset classes in the previous table. Additional target allocations are identified for specific classes of equity securities. The asset allocation ranges established by the investment policy are based upon a long-term investment perspective. The ranges are more heavily weighted toward equity securities since the liabilities of the pension and other postretirement benefit plans are long-term in nature and historically equity securities have significantly outperformed other asset classes over long periods of time.

Equity security investments are restricted to high-quality, readily marketable securities that are actively traded on the major U.S. and foreign national exchanges. Investment in Williams' securities or an entity in which Williams has a majority ownership is prohibited except where these securities may be owned in a commingled investment vehicle in which the pension plans' trust invests. No more than five percent of the total stock portfolio valued at market may be invested in the common stock of any one corporation. The following securities and transactions are not authorized: unregistered securities, commodities or commodity contracts, short sales or margin transactions or other leveraging strategies. Investment strategies using options or futures are not authorized.

Debt security investments are restricted to high-quality, marketable securities that include U.S. Treasury, federal agencies and U.S. Government guaranteed obligations, and investment grade corporate issues. The overall rating of the debt security assets is required to be at least “A”, according to the Moody’s or Standard & Poor’s rating system. No more than five percent of the total portfolio at the time of purchase may be invested in the debt securities of any one issuer. U.S. Government guaranteed and agency securities are exempt from this provision.

During 2007, 11 active investment managers and one passive investment manager managed substantially all of the pension and other postretirement benefit plans’ funds, each of whom had responsibility for managing a specific portion of these assets.

Plan Benefit Payments and Employer Contributions

The following are the expected benefits to be paid by the plan and the expected federal prescription drug subsidy to be received in the next ten years. These estimates are based on the same assumptions previously discussed and reflect future service as appropriate. The actuarial assumptions are based on long-term expectations and include, but are not limited to, assumptions as to average expected retirement age and form of benefit payment. Actual benefit payments could differ significantly from expected benefit payments if near-term participant behaviors differ significantly from the actuarial assumptions.

	Pension Benefits	Other Postretirement Benefits	Federal Prescription Drug Subsidy
		(Millions)	
2008	$ 46	$ 20	$ (2)
2009	40	21	(2)
2010	36	21	(2)
2011	37	22	(2)
2012	43	21	(2)
2013 - 2017	265	110	(15)

We expect to contribute approximately $41 million to our pension plans and approximately $15 million to our other postretirement benefit plans in 2008.

Defined Contribution Plans

We also maintain defined contribution plans for the benefit of substantially all of our employees. Generally, plan participants may contribute a portion of their compensation on a pre-tax and after-tax basis in accordance with the plan’s guidelines. We match employees’ contributions up to certain limits. Costs recognized for these plans were $22 million in 2007, $19 million in 2006, and $17 million in 2005. One of our defined contribution plans was amended as of July 1, 2005, to convert one of the funds within the plan to a nonleveraged employee stock ownership plan (ESOP). The 2005 compensation cost related to the ESOP of $1 million is included in the $17 million of contributions, previously mentioned above, and represents the contribution made in consideration for employee services rendered in 2005. It is measured by the amount of cash contributed to the ESOP. The shares held by the ESOP are treated as outstanding when computing earnings per share and the dividends on the shares held by the ESOP are recorded as a component of retained earnings. For 2006 and future years, there were and will be no contributions to this ESOP, other than dividend reinvestment, as contributions for purchase of our stock is now restricted within this defined contribution plan.

Note 8. Inventories

Inventories at December 31, 2007, and 2006, are as follows:

	2007	2006
	(Millions)	
Natural gas liquids	$ 66	$ 78
Natural gas in underground storage	45	78
Materials, supplies and other	98	82
	$ 209	$ 238

Inventories determined using the LIFO cost method were less than 1 percent and 11 percent of *inventories* at December 31, 2007 and 2006, respectively. The remaining *inventories* were primarily determined using the average-cost method.

If *inventories* valued using the LIFO cost method at December 31, 2007 and 2006, were valued at current replacement cost, the amounts would increase by less than $1 million and $22 million, respectively.

Note 9. Property, Plant and Equipment

Property, plant and equipment — net at December 31, 2007, and 2006, is as follows:

	2007	2006
	(Millions)	
Cost:		
Exploration & Production	$ 7,660	$ 5,918
Gas Pipeline	9,525	9,127
Midstream Gas & Liquids(1)	5,285	4,590
Gas Marketing Services	63	69
Other	254	245
	22,787	19,949
Accumulated depreciation, depletion and amortization	(6,806)	(5,791)
	$ 15,981	$ 14,158

(1) Certain assets above are currently pledged as collateral to secure debt. (See Note 11.)

Depreciation, depletion and amortization expense for *property, plant and equipment — net* was $1.1 billion in 2007, $863 million in 2006, and $736 million in 2005.

Property, plant and equipment — net includes approximately $980 million at December 31, 2007, and $685 million at December 31, 2006, of construction in progress which is not yet subject to depreciation. In addition, property of Exploration & Production includes approximately $378 million at December 31, 2007, and $414 million at December 31, 2006, of capitalized costs related to properties with unproven reserves not yet subject to depletion.

Property, plant and equipment — net includes approximately $1.1 billion at December 31, 2007 and 2006 related to amounts in excess of the original cost of the regulated facilities within Gas Pipeline as a result of our prior acquisitions. This amount is being amortized over 40 years using the straight-line amortization method. Current FERC policy does not permit recovery through rates for amounts in excess of original cost of construction.

Asset Retirement Obligations

The asset retirement obligation at December 31, 2007 and 2006 is $399 million and $333 million, respectively. The increases in the obligation in 2007 are due to revisions in our estimation of our asset retirement obligation in our Midstream segment, increased asset additions in our Exploration and Production segment and increased accretion in our Gas Pipeline segment. The increases in the obligation in 2006 were due primarily to obtaining additional information that revised our estimation of our asset retirement obligation for certain assets in our Exploration & Production, Gas Pipeline, and Midstream segments. Factors affected by the additional information included estimated settlement dates, estimated settlement costs, and inflation rates.

The accrued obligations relate to producing wells, underground storage caverns, offshore platforms, fractionation facilities, gas gathering well connections and pipelines, and gas transmission facilities. At the end of the useful life of each respective asset, we are legally obligated to plug both producing wells and storage caverns and remove any related surface equipment, remove surface equipment and restore land at fractionation facilities, to dismantle offshore platforms, to cap certain gathering pipelines at the wellhead connection and remove any related surface equipment, and to remove certain components of gas transmission facilities from the ground.

Note 10. Accounts Payable and Accrued Liabilities

Under our cash-management system, certain cash accounts reflected negative balances to the extent checks written have not been presented for payment. These negative balances represent obligations and have been reclassified to *accounts payable. Accounts payable* includes approximately $96 million of these negative balances at December 31, 2007, and $44 million at December 31, 2006.

Accrued liabilities at December 31, 2007, and 2006, are as follows:

	2007	2006
	(Millions)	
Interest	$ 208	$ 243
Employee costs	174	155
Taxes other than income taxes	169	152
Estimated rate refund liability	96	2
Accrual for Gulf Liquids litigation contingency	94**	95*
Income taxes	75	81
Guarantees and payment obligations related to WilTel	39	41
Customer margin deposits payable	10	129
Structured indemnity settlement	—	34
Other, including other loss contingencies	293	421
	$ 1,158	$ 1,353

* Includes $22 million of interest.

** Includes $25 million of interest.

Note 11. Debt, Leases and Banking Arrangements

Long-Term Debt

Long-term debt at December 31, 2007 and 2006, is:

	Weighted-Average Interest Rate(1)	December 31, 2007(2)	December 31, 2006
		(Millions)	
Secured(3)			
6.62%-9.45%, payable through 2016	8.0%	$ 148	$ 172
Adjustable rate, payable through 2016	6.3%	64	74
Capital lease obligations	6.7%	10	2
Unsecured			
5.5%-10.25%, payable through 2033(4)	7.6%	7,103	7,691
Revolving credit loans	5.7%	250	—
Adjustable rate, payable through 2012	6.2%	325	75
Total long-term debt, including current portion		7,900	8,014
Long-term debt due within one year		(143)	(392)
Long-term debt		$ 7,757	$ 7,622

(1) At December 31, 2007.

(2) Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens, sell assets, make certain distributions, repurchase equity and incur additional debt.

(3) Includes $212 million and $246 million at December 31, 2007 and 2006, respectively, collateralized by certain fixed assets of two of our Venezuelan subsidiaries with a net book value of $351 million and $380 million at December 31, 2007 and 2006, respectively.

(4) 2007 includes Transco's $100 million 6.25 percent notes, due on January 15, 2008, that were reclassified as long-term debt as a result of a subsequent refinancing under the $1.5 billion revolving credit facility.

Revolving credit and letter of credit facilities (credit facilities)

We have an unsecured, $1.5 billion revolving credit facility with a maturity date of May 1, 2012. Northwest Pipeline and Transco each have access to $400 million under the facility to the extent not otherwise utilized by us. Interest is calculated based on a choice of two methods: a fluctuating rate equal to the lender's base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. We are required to pay a commitment fee (currently 0.125 percent) based on the unused portion of the facility. The margins and commitment fee are generally based on the specific borrower's senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include the following:

- Our ratio of debt to capitalization must be no greater than 65 percent. At December 31, 2007, we are in compliance with this covenant as our ratio of debt to capitalization, as calculated under this covenant, is approximately 51 percent.
- Ratio of debt to capitalization must be no greater than 55 percent for Northwest Pipeline and Transco. At December 31, 2007, we are in compliance with this covenant as our ratio of debt to capitalization, as calculated under this covenant, is approximately 36 percent for Northwest Pipeline and 31 percent for Transco.

Our $500 million and $700 million facilities provide for both borrowings and issuing letters of credit but are expected to be used primarily for issuing letters of credit. These facilities mature in 2009 and 2010, respectively. We are required to pay the funding bank fixed fees at a weighted-average interest rate of 3.64 percent and 2.29 percent for the $500 million and $700 million facilities, respectively, on the total committed amount of the facilities. In addition, we pay interest on any borrowings at a fluctuating rate comprised of either a base rate or LIBOR.

The funding bank syndicated its associated credit risk through a private offering that allows for the resale of certain restricted securities to qualified institutional buyers. To facilitate the syndication of these facilities, the bank established trusts funded by the institutional investors. The assets of the trusts serve as collateral to reimburse the bank for our borrowings in the event that the facilities are delivered to the investors as described below. Thus, we have no asset securitization or collateral requirements under the facilities. Upon the occurrence of certain credit events, letters of credit under the agreement become cash collateralized creating a borrowing under the facilities. Concurrently, the funding bank can deliver the facilities to the institutional investors, whereby the investors replace the funding bank as lender under the facilities. Upon such occurrence, we will pay:

	$500 Million Facility		$700 Million Facility	
	$400 million	$100 million	$500 million	$200 million
Interest Rate	3.57 percent	LIBOR	4.35 percent	LIBOR
Facility Fixed Fee	3.19 percent		2.29 percent	

In December 2007, Williams Partners L.P. acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million. Williams Partners L.P completed the transaction after successfully closing a public equity offering of 9.25 million common units that yielded net proceeds of approximately $335 million. The partnership financed the remainder of the purchase price primarily through utilizing $250 million of term loan borrowings and issuing approximately $157 million of common units to us. The $250 million term loan is under Williams Partners L.P.'s new $450 million five-year senior unsecured credit facility that became effective simultaneous with the closing of the Wamsutter transaction. This $450 million credit facility is comprised initially of a $200 million revolving credit facility available for borrowings and letters of credit and a $250 million term loan. Under certain conditions, the revolving credit facility may be increased up to an additional $100 million. Interest on borrowings under this agreement will be payable at rates per annum equal to either (1) a fluctuating base rate equal to the lender's prime rate plus the applicable margin, or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. At December 31, 2007, there were no amounts outstanding under the $200 million revolving credit facility.

In December 2007, Northwest Pipeline borrowed $250 million under the $1.5 billion revolving credit facility to retire its $250 million 6.625 percent notes that matured on December 1, 2007.

Letters of credit issued under our credit facilities are:

	Letters of Credit at December 31, 2007 (Millions)
$500 million unsecured credit facilities	$ 243
$700 million unsecured credit facilities	$ 99
$1.5 billion unsecured credit facility	$ 28

Exploration & Production's credit agreement

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

Issuances and retirements

On May 28, 2003, we issued $300 million of 5.5 percent junior subordinated convertible debentures due 2033. These notes, which are callable after seven years, are convertible at the option of the holder into our common stock at a conversion price of approximately $10.89 per share. In November 2005, we initiated an offer to convert these debentures to shares of our common stock. In January 2006, we converted approximately $220 million of the debentures. (See Note 12.)

In June 2006, Williams Partners L.P. acquired 25.1 percent of our interest in Williams Four Corners LLC for $360 million. The acquisition was completed after Williams Partners L.P. successfully closed a $150 million private debt offering of 7.5 percent senior unsecured notes due 2011 and a public equity offering of approximately $225 million in net proceeds.

In December 2006, Williams Partners L.P. acquired the remaining 74.9 percent interest in Williams Four Corners LLC for $1.223 billion. The acquisition was completed after Williams Partners L.P. successfully closed a $600 million private debt offering of 7.25 percent senior unsecured notes due 2017, a private equity offering of approximately $350 million of common and Class B units, and a public equity offering of approximately $294 million in net proceeds.

In connection with the issuance of the $150 million 7.5 percent notes and the $600 million 7.25 percent notes discussed above, Williams Partners L.P. entered into registration rights agreements with the initial purchasers of the senior unsecured notes. In these agreements they agreed to conduct a registered exchange offer for the senior unsecured notes or cause to become effective a shelf registration statement providing for resale of the senior unsecured notes. Williams Partners L.P. initiated exchange offers for both series on April 10, 2007. The exchange offers were completed and closed on May 11, 2007.

In connection with the issuance of approximately $350 million of common and Class B units in a private equity offering discussed above, Williams Partners L.P. entered into a registration rights agreement with the initial purchasers whereby Williams Partners L.P. agreed to file a shelf registration statement providing for the resale of the common units purchased. Additionally, the registration rights agreement provides for the registration of common units that would be issued upon conversion of the Class B units. Williams Partners L.P. filed the shelf registration statement on January 12, 2007, and it became effective on March 13, 2007. On May 21, 2007, Williams Partners L.P.'s outstanding Class B units were converted into common units on a one-for-one basis. If the shelf registration statement is unavailable for a period that exceeds an aggregate of 30 days in any 90-day period or 105 days in any 365-day period, the purchasers are entitled to receive liquidated damages. Liquidated damages are calculated as 0.25 percent of the Liquidated Damages Multiplier per 30-day period for the first 60 days following the 90th day, increasing by an additional 0.25 percent of the Liquidated Damages Multiplier per 30-day period for each subsequent 60 days, up to a maximum of 1.00 percent of the Liquidated Damages Multiplier per 30-day period, provided the aggregate amount of liquidated damages payable to any purchaser is capped at 10 percent of the Liquidated Damages Multiplier. The Liquidated Damages Multiplier is (i) the product of $36.59 times the number of common units purchased plus (ii) the product of $35.81 times the number of Class B units purchased. Due to amendments made to Rule 144 of the Securities Act in February 2008, related to securities acquired by non-affiliates from an issuer subject to public reporting requirements, Williams Partners L.P. no longer has an obligation to keep their shelf registration statement effective and would have no liability for a failure to do so.

The debt and equity issued to third parties by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively.

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior unsecured notes due 2010. Northwest Pipeline paid premiums of approximately $7 million in conjunction with the early debt retirement. These premiums are considered recoverable through rates and are therefore deferred as a component of *other assets and deferred charges* on our consolidated balance sheet, amortizing over the life of the original debt.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement. In August 2007, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

Under the terms of the Northwest Pipeline $185 million 5.95 percent senior unsecured notes mentioned above, Northwest Pipeline was obligated to file a registration statement for an offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 180 days from closing and use its commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing. Northwest Pipeline initiated an exchange offer on July 26, 2007, which expired on August 23, 2007. Northwest Pipeline received full participation in the exchange offer.

During December 2007, we repurchased $22 million of our 8.125 percent senior unsecured notes due March 2012 and $213 million of our 7.125 percent senior unsecured notes due September 2011. In conjunction with these early retirements, we paid premiums of approximately $19 million. These premiums, as well as related fees and expenses are recorded as *early debt retirement costs* in the Consolidated Statement of Income.

Aggregate minimum maturities of *long-term debt* (excluding capital leases and unamortized discount and premium) for each of the next five years are as follows:

	(Millions)
2008	$ 138
2009	53
2010	39
2011	955
2012	1,576

Cash payments for interest (net of amounts capitalized) were as follows: 2007 — $634 million; 2006 — $611 million; and 2005 — $625 million.

Leases-Lessee

Future minimum annual rentals under noncancelable operating leases as of December 31, 2007, are payable as follows:

	(Millions)
2008	$ 83
2009	63
2010	30
2011	15
2012	13
Thereafter	19
Total	$ 223

Total rent expense was $68 million in 2007, $68 million in 2006, and $65 million in 2005. Rent expense reported as discontinued operations, primarily related to a tolling agreement, was $148 million in 2007, $175 million in 2006, and $161 million in 2005. Rent expense in discontinued operations was offset by approximately $276 million in 2007, $264 million in 2006, and $172 million in 2005 resulting from sales and other transactions made possible by the tolling agreement. This tolling agreement was included in the sale of our power business to Bear Energy, LP. (See Note 2.)

Note 12. Stockholders' Equity

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open-market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. During 2007, we purchased approximately 16 million shares for $526 million (including transaction costs) under the program at an average cost of $33.08 per share. This stock repurchase is recorded in *treasury stock* on the Consolidated Balance Sheet.

In November 2005, we initiated an offer to convert our 5.5 percent junior subordinated convertible debentures into our common stock. In January 2006, we converted approximately $220 million of the debentures in exchange for 20 million shares of common stock, a $26 million cash premium, and $2 million of accrued interest.

We maintain a Stockholder Rights Plan, as amended and restated on September 21, 2004, and further amended May 18, 2007, and October 12, 2007, under which each outstanding share of our common stock has a right (as defined in the plan) attached. Under certain conditions, each right may be exercised to purchase, at an exercise price of $50 (subject to adjustment), one two-hundredth of a share of Series A Junior Participating Preferred Stock. The rights may be exercised only if an Acquiring Person acquires (or obtains the right to acquire) 15 percent or more of our common stock or commences an offer for 15 percent or more of our common stock. The plan contains a mechanism to divest of shares of common stock if such stock in excess of 14.9 percent was acquired inadvertently or without knowledge of the terms of the rights. The rights, which until exercised do not have voting rights, expire in 2014 and may be redeemed at a price of $.01 per right prior to their expiration, or within a specified period of time after the occurrence of certain events. In the event a person becomes the owner of more than 15 percent of our common stock, each holder of a right (except an Acquiring Person) shall have the right to receive, upon exercise, our common stock having a value equal to two times the exercise price of the right. In the event we are engaged in a merger, business combination, or 50 percent or more of our assets, cash flow or earnings power is sold or transferred, each holder of a right (except an Acquiring Person) shall have the right to receive, upon exercise, common stock of the acquiring company having a value equal to two times the exercise price of the right.

Note 13. Stock-Based Compensation

Plan Information

Effective May 17, 2007, our stockholders approved a new plan that provides common-stock-based awards to both employees and nonmanagement directors. The new plan generally contains terms and provisions consistent with the previous plans. The new plan reserves 19 million shares for issuance. Awards outstanding in all prior plans remain in those plans with their respective terms and provisions. No new grants will be made from the prior plans. The new plan permits the granting of various types of awards including, but not limited to, restricted stock units and stock options. Restricted stock units are generally valued at market value on the grant date of the award and generally vest over three years. The purchase price per share for stock options generally may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable over a three-year period from the date of the grant and can be subject to accelerated vesting if certain future stock prices or if specific financial performance targets are achieved. Stock options generally expire 10 years after grant. At December 31, 2007, 37 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 19 million shares were available for future grants.

Additionally, on May 17, 2007, our stockholders approved an Employee Stock Purchase Plan (ESPP) which authorizes up to 2 million shares of our common stock to be available for sale under the plan. The ESPP enables eligible participants to purchase our common stock through payroll deductions not exceeding an annual amount of $15,000 per participant. The ESPP provides for offering periods during which shares may be purchased and continues until the earliest of: (1) the Board of Directors terminates the ESPP, (2) the sale of all shares available under the ESPP, or (3) the tenth anniversary of the date the Plan was approved by the stockholders. The first offering under the ESPP commenced on October 1, 2007 and ended on December 31, 2007. Subsequent offering periods will be from January through June and from July through December. Generally, all employees are eligible to participate in the ESPP, with the exception of executives and international employees. The number of shares eligible for an employee to purchase during each offering period is limited to 750 shares. The purchase price of the stock is 85 percent of the lower closing price of either the first or the last day of the offering period. The ESPP requires a one-year holding period before the stock can be sold. Approximately 2 million shares were available for purchase under the ESPP at December 31, 2007.

Stock Options

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. Stock options generally become exercisable over a three-year period from the date of grant and generally expire ten years after the grant.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following summary reflects stock option activity and related information for the year ending December 31, 2007.

Stock Options	Options (Millions)	Weighted-Average Exercise Price	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2006	17.7	$ 16.96	
Granted	1.2	$ 28.32	
Exercised	(4.1)	$ 13.78	$ 74
Cancelled	(1.6)	$ 36.04	
Outstanding at December 31, 2007	13.2	$ 16.62	$ 256
Exercisable at December 31, 2007	10.4	$ 14.79	$ 222

The total intrinsic value of options exercised during the years ended December 31, 2007, 2006, and 2005 was $74 million, $36 million, and $42 million, respectively.

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2007.

	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)
$2.27 to $12.92	6.0	$ 6.98	4.9	6.0	$ 6.98	4.9
$12.93 to $23.72	4.4	$ 19.41	6.9	2.8	$ 18.87	6.5
$23.73 to $34.52	1.4	$ 28.25	7.7	.3	$ 28.00	2.2
$34.53 to $45.32	1.4	$ 37.68	1.9	1.3	$ 37.68	1.9
Total	13.2	$ 16.62	5.6	10.4	$ 14.79	4.9

The estimated fair value at date of grant of options for our common stock granted in 2007, 2006, and 2005, using the Black-Scholes option pricing model, is as follows:

	2007	2006	2005
Weighted-average grant date fair value of options for our common stock granted during the year	$ 9.09	$ 8.36	$ 6.70
Weighted-average assumptions:			
Dividend yield	1.5%	1.4%	1.6%
Volatility	28.7%	36.3%	33.3%
Risk-free interest rate	4.6%	4.7%	4.1%
Expected life (years)	6.3	6.5	6.5

The expected dividend yield is based on the average annual dividend yield as of the grant date. Expected volatility is based on the historical volatility of our stock and the implied volatility of our stock based on traded options. In calculating historical volatility, returns during calendar year 2002 were excluded as the extreme volatility during that time is not reasonably expected to be repeated in the future. The risk-free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life of the option is based on historical exercise behavior and expected future experience.

Cash received from stock option exercises was $56 million, $34 million and $39 million during 2007, 2006 and 2005, respectively. The tax benefit realized from stock options exercised during 2007 was $27 million and $14 million for both 2006 and 2005.

Nonvested Restricted Stock Units

Restricted stock units are generally valued at market value on the grant date and generally vest over three years. Restricted stock unit expense, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2007.

Restricted Stock Units	Shares (Millions)	Weighted-Average Fair Value*
Nonvested at December 31, 2006	3.7	$ 20.57
Granted	1.8	$ 30.79
Forfeited	(0.1)	$ 23.53
Vested	(1.0)	$ 15.39
Nonvested at December 31, 2007	4.4	$ 27.78

* Performance-based shares are valued at the end-of-period market price until certification that the performance objectives have been completed. Upon certification, these shares are valued at that day's end-of-period market price. All other shares are valued at the grant-date market price.

Other restricted stock unit information

	2007	2006	2005
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$ 30.79	$ 23.39	$ 19.35
Total fair value of restricted stock units vested during the year ($'s in millions)	$ 33	$ 15	$ 14

Performance-based shares granted under the Plan represent 38 percent of nonvested restricted stock units outstanding at December 31, 2007. These grants are generally earned at the end of a three-year period based on actual performance against a performance target. Expense associated with these performance-based grants is recognized in periods after performance targets are established. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

Note 14. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk

Financial Instruments

Fair-value methods

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

<u>Cash and cash equivalents and restricted cash</u>: The carrying amounts reported in the balance sheet approximate fair value due to the short-term maturity of these instruments.

Other securities, notes and other noncurrent receivables, structured indemnity settlement obligation, margin deposits, and customer margin deposits payable: The carrying amounts reported in the balance sheet approximate fair value as these instruments have interest rates approximating market. *Other securities* in the table below consists of auction rate securities and held-to-maturity securities and are reported, along with margin deposits, in *other current assets and deferred charges* in the Consolidated Balance Sheet.

Long-term debt: The fair value of our publicly traded long-term debt is valued using indicative year-end traded bond market prices. Private debt is valued based on the prices of similar securities with similar terms and credit ratings. At December 31, 2007 and 2006, approximately 90 percent and 87 percent, respectively, of our long-term debt was publicly traded.

Guarantees: The *guarantees* represented in the table below consist primarily of guarantees we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on certain lease performance obligations. To estimate the fair value of the guarantees, the estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate for each guarantee based on the credit rating of WilTel's current owner and the term of the underlying obligation. The default rates are published by Moody's Investors Service.

Energy derivatives: Energy derivatives include:

- Futures contracts;
- Forward contracts;
- Swap agreements;
- Option contracts.

The fair value of energy derivatives is determined based on the nature of the underlying transaction and the market in which the transaction is executed. We execute most of these transactions on an organized commodity exchange or in over-the-counter markets in which quoted prices exist for active periods. For contracts with terms that exceed the time period for which actively quoted prices are available, we determine fair value by estimating commodity prices during the illiquid periods utilizing internally developed valuations incorporating information obtained from commodity prices in actively quoted markets, quoted prices in less active markets, prices reflected in current transactions, and other market fundamental analysis.

Carrying amounts and fair values of our financial instruments

Asset (Liability)	2007 Carrying Amount	2007 Fair Value	2006 Carrying Amount	2006 Fair Value
	(Millions)			
Cash and cash equivalents	$ 1,699	$ 1,699	$ 2,269	$ 2,269
Restricted cash (current and noncurrent)	127	127	126	126
Other securities	20	20	103	103
Notes and other noncurrent receivables	4	4	4	4
Cost based investments (see Note 3)	25	(a)	52	(a)
Long-term debt, including current portion (see Note 11)(b)	(7,890)	(8,729)	(8,012)	(8,480)
Structured indemnity settlement obligation	—	—	(34)	(34)
Margin deposits	76	76	59	59
Customer margin deposits payable	(10)	(10)	(129)	(129)
Guarantees	(40)	(34)	(42)	(35)
Net energy derivatives:				
Energy commodity cash flow hedges(d)	(268)	(268)	365	365
Other energy derivatives(d)	(100)	(100)	70	70
Other derivatives(c)	—	—	2	2

(a) These investments are primarily in nonpublicly traded companies for which it is not practicable to estimate fair value.

(b) Excludes capital leases.

(c) Consists of nonenergy cash flow hedges.

(d) A portion of these derivatives is included in assets and liabilities of discontinued operations. (See Note 2.)

Energy Derivatives

Our energy derivative contracts include the following:

Futures contracts: Futures contracts are standardized commitments through an organized commodity exchange to either purchase or sell a commodity at a future date for a specified price. Futures are generally settled in cash, but may be settled through delivery of the underlying commodity. The fair value of these contacts is generally determined using quoted prices.

Forward contracts: Forward contracts are over-the-counter commitments to either purchase or sell a commodity at a future date for a specified price, which involve physical delivery of energy commodities, and may contain either fixed or variable pricing terms. Forward contracts are valued based on prices of the underlying energy commodities over the contract life and contractual or notional volumes with the resulting expected future cash flows discounted to a present value using a risk-free market interest rate.

Swap agreements: Swap agreements require us to make payments to (or receive payments from) counterparties based upon the differential between a fixed and variable price or between variable prices of energy commodities at different locations. Swap agreements are valued based on prices of the underlying energy commodities over the contract life and contractual or notional volumes with the resulting expected future cash flows discounted to a present value using a risk-free market interest rate.

Option contracts: Physical and financial option contracts give the buyer the right to exercise the option and receive the difference between a predetermined strike price and a market price at the date of exercise. An option to purchase and an option to sell can be combined in an instrument called a collar to set a minimum and maximum transaction price. These contracts are valued based on option pricing models considering prices of the underlying energy commodities over the contract life, volatility of the commodity prices, contractual volumes, estimated volumes under option and other arrangements, and a risk-free market interest rate.

Energy commodity cash flow hedges

We are exposed to market risk from changes in energy commodity prices within our operations. We 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 natural gas liquids (NGLs) attributable to commodity price risk. Certain of these derivatives have been designated as cash flow hedges under SFAS No. 133.

Our Exploration & Production segment produces, buys and sells natural gas at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in natural gas market prices, we enter into natural gas futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. Exploration & Production's cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

Our Midstream segment produces and sells NGLs at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices, we hedge price risk by entering into NGL swap agreements, financial forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs. 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.

Changes in the fair value of our cash flow hedges are deferred in other comprehensive income and are reclassified into *revenues* 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. During 2006, we reclassified approximately $1 million of net gains from other comprehensive income to earnings as a result of the discontinuance of cash flow hedges because the forecasted transaction did not occur by the end of the originally specified time period. In second-quarter 2007, we recognized a net gain of $429 million (reported in *revenues* of discontinued operations) associated with the reclassification of deferred net hedge gains of our former power business from *accumulated other comprehensive income/loss* to earnings. This reclassification was based on the determination that the forecasted transactions related to the derivative cash flow hedges being sold to Bear Energy, LP were probable of not occurring. See Note 2 for further discussion. Approximately $14 million of net losses and $17 million of net gains from hedge ineffectiveness are included in *revenues* during 2007 and 2006, respectively. For 2007 and 2006, there are no derivative gains or losses excluded from the assessment of hedge effectiveness. As of December 31, 2007, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to three years. Based on recorded values at December 31, 2007, approximately $35 million of net losses (net of income tax benefit of $22 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of December 31, 2007. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized in 2008 will likely differ from these values. These gains or losses will offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Other energy derivatives

Our Gas Marketing Services and Exploration & Production segments have other energy derivatives that have not been designated or do not qualify as SFAS No. 133 hedges. As such, the net change in their fair value is recognized in *revenues* in the Consolidated Statement of Income. Even though they do not qualify for hedge accounting (see *derivative instruments and hedging activities* in Note 1 for a description of hedge accounting), certain of these derivatives hedge our future cash flows on an economic basis.

Other energy-related contracts

We also hold significant nonderivative energy-related contracts, such as storage and transportation agreements, in our Gas Marketing Services portfolio. These have not been included in the financial instruments table above or in our Consolidated Balance Sheet because they are not derivatives as defined by SFAS No. 133.

Guarantees

In addition to the guarantees and payment obligations discussed elsewhere in these footnotes (see Notes 3 and 15), we have issued guarantees and other similar arrangements with off-balance sheet risk as discussed below.

In connection with agreements executed prior to our acquisition of Transco to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers which 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 substantially exceed the minimum purchase price.

We are required by certain foreign 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 domestic taxes required to be paid by the foreign 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 $44 million at December 31, 2007, and $46 million at December 31, 2006. Our exposure declines systematically throughout the remaining term of WilTel’s obligations. The carrying value of these guarantees is approximately $39 million at December 31, 2007.

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.

Concentration of Credit Risk

Cash equivalents

Our cash equivalents consist of high-quality securities placed with various major financial institutions with credit ratings at or above BBB by Standard & Poor's or Baa1 by Moody's Investors Service.

Accounts and notes receivable

The following table summarizes concentration of receivables including those related to discontinued operations (see Note 2), net of allowances, by product or service at December 31, 2007 and 2006:

	2007	2006
	(Millions)	
Receivables by product or service:		
Sale or transportation of natural gas and related products	$ 1,139	$ 895
Sales of power and related services	55	270
Interest	5	39
Other	48	9
Total	$ 1,247	$ 1,213

Natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the eastern and northwestern United States, Rocky Mountains, Gulf Coast, Venezuela and Canada. Prior to the sale of substantially all of our power business, which was completed in November 2007, customers for power included the California Independent System Operator (ISO), the California Department of Water Resources, and other power marketers and utilities located throughout the United States. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

Derivative assets and liabilities

We have a risk of loss as a result of 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 results from items including credit considerations and the regulatory environment for 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. Additional collateral support could include the following:

- Letters of credit;
- Payment under margin agreements;
- Guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk.

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations (see Note 2), as of December 31, 2007, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 78	$ 79
Energy marketers and traders	224	1,328
Financial institutions	1,302	1,302
Other	—	1
	$ 1,604	2,710
Credit reserves		(1)
Gross credit exposure from derivatives		$ 2,709

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 December 31, 2007, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 17	$ 17
Energy marketers and traders	18	20
Financial institutions	45	45
Other	—	—
	$ 80	82
Credit reserves		(1)
Net credit exposure from derivatives		$ 81

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor’s of BBB− or Moody’s Investors Service rating of Baa3 in investment grade. We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, parent company guarantees, and property interests, as investment grade.

Revenues

In 2007, 2006 and 2005, there were no customers for which our sales exceeded 10 percent of our consolidated revenues.

Note 15. Contingent Liabilities and Commitments

Rate and Regulatory Matters and Related Litigation

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result, a portion of the revenues of these subsidiaries has been collected subject to refund. We have accrued a liability for these potential refunds as of December 31, 2007, which we believe is adequate for any refunds that may be required.

We are party to pending matters involving pipeline transportation rates charged to our former Alaska refinery in prior periods. While we have no loss exposure in these matters, favorable resolution could result in refunds. In February 2008, the Alaska Supreme Court ruled in our favor in one of these cases. This ruling may be subject to further appeal.

Issues Resulting from California Energy Crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the Federal Energy Regulatory Commission (FERC). 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 2006 Ninth Circuit Court of Appeals decision, which the U.S. Supreme Court has agreed to review, certain contracts that we entered into during 2000 and 2001 may be subject to partial refunds. These contracts, under which we sold electricity, totaled approximately $89 million in revenue. We expect the U.S. Supreme Court's decision in the second quarter 2008. While we are not a party to the cases involved in the appellate court decision under review, 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 decision and the FERC's reconsideration of the contract terms at issue in the decision.

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 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. As part of the State Settlement, we were to pay an additional $45 million to the California Attorney General over three years. Upon the sale of our power business in November 2007 (see Note 2), we paid the entire remaining balance on a discounted basis.

We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling approximately $24 million at December 31, 2007. 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, were and continue to be made to the Ninth Circuit Court of Appeals and the U.S. Supreme Court. In August 2006, the Ninth Circuit issued its order that largely upheld the FERC's prior rulings, but it expanded the types of transactions that were made subject to refund. This order is subject to further appeal. Because of our settlements, we do not expect that the

August 2006 decision will have a material impact on us. However, the final refund calculation has not been made because of the appeals and certain unclear aspects of the refund calculation process.

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.
- 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 Tennessee purchasers have appealed the Tennessee state court's February 2007 dismissal of their case. The Missouri case has been remanded to Missouri state court. The cases in the other jurisdictions have been removed and transferred to the federal court in Nevada. On February 19, 2008, the federal court granted summary judgment in the Colorado case in favor of us and most of the other defendants. We expect that the Colorado plaintiffs will appeal.

Mobile Bay Expansion

In December 2002, an administrative law judge at the FERC issued an initial decision in Transcontinental Gas Pipe Line Corporation's (Transco) 2001 general rate case which, among other things, rejected the recovery of the costs of Transco's Mobile Bay expansion project from its shippers on a "rolled-in" basis and found that incremental pricing for the Mobile Bay expansion project is just and reasonable. In March 2004, the FERC issued an Order on Initial Decision in which it reversed certain parts of the administrative law judge's decision and accepted Transco's proposal for rolled-in rates. Gas Marketing Services holds long-term transportation capacity on the Mobile Bay expansion project. If the FERC had adopted the decision of the administrative law judge on the pricing of the Mobile Bay expansion project and also required that the decision be implemented effective September 1, 2001, Gas Marketing Services could have been subject to surcharges of approximately $139 million, including interest, through December 31, 2007, in addition to increased costs going forward. Certain parties filed appeals in federal court seeking to overturn the FERC's ruling on the rolled-in rates. Gas Marketing Services has reached an agreement in principle to settle this matter for $10 million.

Environmental Matters

Continuing operations

Since 1989, our Transco subsidiary has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At December 31, 2007, we had accrued liabilities of $6 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, we have estimated our aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above.

Beginning in the mid-1980s, our 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 December 31, 2007, we have accrued liabilities totaling approximately $7 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline's rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At December 31, 2007, we have accrued liabilities totaling approximately $4 million for these costs.

In July 2006, the Colorado Department of Public Health and Environment (CDPHE) issued a Notice of Violation (NOV) to Williams Production RMT Company related to operating permits for our Roan Cliffs and Hayburn gas plants in Garfield County, Colorado. We have met with the CDPHE to discuss the allegations contained in the NOV and have provided additional requested information to the agency.

On April 11, 2007, the New Mexico Environment Department's Air Quality Bureau (NMED) issued an NOV to Williams Four Corners, LLC that alleged various emission and reporting violations in connection with our Lybrook gas processing plant's flare and leak detection and repair program. The NMED proposed a penalty of approximately $3 million. We are discussing the basis for and the scope of the proposed penalty with the NMED.

On April 16, 2007, the CDPHE issued an NOV to Williams Production RMT Company related to alleged air permit violations at the Rifle Station natural gas dehydration facility located in Garfield County, Colorado. The Rifle Station facility had been shut down prior to our receipt of the NOV and, except for some minor operations, remains closed. We responded to the CDPHE's notice on May 15, 2007.

On April 27, 2007, the Wyoming Department of Environmental Quality (WDEQ) issued an NOV to Williams Production RMT Company that alleged violations of various Wyoming Pollution Discharge Elimination System permits for our coal bed methane gas production facilities in the state. We are discussing the matter with the WDEQ and expect the penalty to be approximately $48,000.

Williams Production RMT Company performed voluntary audits of its 2006 and 2007 compliance with state and federal air regulations. In June 2007, we disclosed to the CDPHE, pursuant to its audit immunity privilege, our facilities that were not in compliance. We also described corrective actions that had or would be taken to remedy the issues. In January 2008, the Colorado Attorney General's office informed us of its opinion that our disclosures do not qualify for the audit privilege immunity. We are currently negotiating with the CDPHE and the Attorney General's office about this matter.

By letter dated September 20, 2007, the EPA required our Transco subsidiary to provide 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. We have responded with the requested information.

Former operations, including operations classified as discontinued

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

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At December 31, 2007, we have accrued liabilities of approximately $8 million for such excess costs.

Other

At December 31, 2007, we have accrued environmental liabilities totaling approximately $21 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.

In 2004, our Gulf Liquids subsidiary initiated a self-audit of all environmental conditions (air, water, and waste) at three facilities in Geismar, Sorrento, and Chalmette, Louisiana. The audit revealed numerous infractions of Louisiana environmental regulations and resulted in a Consolidated Compliance Order and Notice of Potential Penalty from the Louisiana Department of Environmental Quality (LDEQ). In October 2007, we paid the agreed $109,000 penalty to the LDEQ as a comprehensive multi-media settlement.

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 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. Grynberg's measurement claims remained pending against us and the other defendants; the court previously dismissed Grynberg's royalty valuation claims. In May 2005, the court-appointed special master entered a report which recommended that the claims against our Gas Pipeline and Midstream subsidiaries be dismissed but upheld the claims against our Exploration & Production subsidiaries against our jurisdictional challenge. In October 2006, the District Court dismissed all claims against us and our wholly owned subsidiaries, and in November 2006, Grynberg filed his notice of appeal with the Tenth Circuit Court of Appeals.

In August 2002, Jack J. Grynberg, and Celeste C. Grynberg, Trustee on Behalf of the Rachel Susan Grynberg Trust, and the Stephen Mark Grynberg Trust, served us and one of our Exploration & Production subsidiaries with a complaint in the state court in Denver, Colorado. The complaint alleges that we have used mismeasurement techniques that distort the British Thermal Unit heating content of natural gas, resulting in the alleged underpayment of royalties to Grynberg and other independent natural gas producers. The complaint also alleges that we inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Under various theories of relief, the plaintiff is seeking actual damages of between $2 million and $20 million based on interest rate variations and punitive damages in the amount of approximately $1 million. In 2004, Grynberg filed an amended complaint against one of our Exploration & Production subsidiaries. This subsidiary filed an answer in January 2005, denying liability for the damages claimed. Trial in this case was originally set for May 2006, but the parties have negotiated an agreement dismissing the measurement claims and deferring further proceedings on the royalty claims until resolution of an appeal in another case. The amount of any possible liability cannot be reasonably estimated at this time.

Securities class actions

Numerous shareholder class action suits were filed against us in 2002 in the United States District Court for the Northern District of Oklahoma. The majority of the suits alleged that we and co-defendants, WilTel, previously an owned subsidiary known as Williams Communications, and certain corporate officers, acted jointly and separately to inflate the stock price of both companies. WilTel was dismissed as a defendant as a result of its bankruptcy. These cases were consolidated and an order was issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriter defendants have requested indemnification and defense from these cases. If we grant the requested indemnifications to the underwriters, any related settlement costs will not be covered by our insurance policies. We covered the cost of defending the underwriters. In 2002, the amended complaints of the WilTel securities holders and of our securities holders added numerous claims. On February 9, 2007, the court gave its final approval to our settlement with our securities holders. We entered into indemnity agreements with certain of our insurers to ensure their timely payment related to this settlement. The carrying value of our estimated liability related to these agreements is immaterial because we believe the likelihood of any future performance is remote.

On July 6, 2007, the court granted various defendants' motions for summary judgment and entered judgment for us and the other defendants in the WilTel matter. The plaintiffs appealed the court's judgment. 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 because our insurance coverage has been fully utilized by the settlement described above. 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.

TAPS Quality Bank

One of our subsidiaries, Williams Alaska Petroleum, Inc. (WAPI), is actively engaged in administrative litigation being conducted jointly by the FERC and the Regulatory Commission of Alaska (RCA) concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank. In 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions, and we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable. Our additional potential refund liability terminated on March 31, 2004, when we sold WAPI's interests in the TAPS pipeline. We subsequently accrued additional amounts for interest.

In 2006, the FERC entered its final order (FERC Final Order), which the RCA adopted, and most of the parties appealed to the D.C. Circuit Court of Appeals. ExxonMobil also filed a similar appeal in the Alaska Superior Court. A key issue pending on appeal is the limited retroactive impact of the FERC Final Order that restricts our exposure for Quality Bank adjustment refunds to periods after February 1, 2000. ExxonMobil asserts that the FERC's reliance on the Highway Reauthorization Act as the basis for limiting the retroactive effect violates, among other things, the separation of powers under the U.S. Constitution by interfering with the FERC's independent decision-making role. We expect a decision from the U.S. Supreme Court on the constitutional issues in 2008.

On June 7, 2007, the FERC stated the Quality Bank Administrator was free to issue invoices without any further action by the FERC. The Quality Bank Administrator issued invoices on July 31, 2007. We estimate that our net obligation for these invoices could be as much as $124 million. This amount remains an estimate because WAPI has not received all invoices to be issued to WAPI that arise out of the Administrator's original invoices to third parties. Amounts accrued in excess of this estimated obligation will be retained pending resolution of all appeals.

Redondo Beach taxes

In February 2005, we and AES Redondo Beach, L.L.C. received a tax assessment letter from the city of Redondo Beach, California, in which the city asserted that approximately $33 million in back taxes and approximately $39 million in interest and penalties are owed related to natural gas used at the generating facility operated by AES Redondo Beach. Hearings were held in July 2005 and in September 2005 the tax administrator for the city issued a decision in which he found us jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately $21 million. Both we and AES Redondo Beach filed notices of appeal that were heard at the city level. In December 2006, the city hearing officer for the appeal of the pre-2005 amounts issued a final decision affirming our utility user tax liability and reversing AES Redondo Beach's liability because the officer ruled that AES Redondo Beach is an exempt public utility. We appealed this decision to the Los Angeles Superior Court, and the city also appealed with respect to AES Redondo Beach. Those appeals were heard on January 25 and February 14, 2008. On April 30, 2007, we paid the city the protested amount of approximately $57 million in order to pursue its appeal. Despite the city hearing officer's unfavorable decision and the payment to preserve our appeal rights, we do not believe a contingent loss is probable.

The city's assessment of our liability for the periods from 1998 through September 2007 is approximately $72 million (inclusive of interest and penalties). We protested all these assessments and requested hearings on them. We and AES Redondo Beach also filed separate refund actions in Los Angeles Superior Court related to certain taxes paid since the initial 2005 notice of assessment. The refund actions are stayed pending the resolution of the appeals. In connection with the sale of our power business (see Note 2), we settled our dispute with AES Redondo Beach by equally sharing, for periods prior to the closing of the sale, any ultimate tax liability as well as the funding of amounts previously paid under protest.

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay 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 estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $25 million, all of which have been accrued as of December 31, 2007. 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. If the judgment is upheld on appeal, our 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 for 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. Apparently agreeing that we could not have known the DOA's position before January 2007, the SBOE did not award interest on the assessment. We estimate that the amount of the additional severance and ad valorem taxes to be approximately $4 million. The Wyoming Supreme Court has agreed to hear our appeal of the SBOE's determination. If the DOA prevails in its interpretation of our obligation and applies the same basis of assessment to subsequent periods, it is reasonably possible that we could owe a total of approximately $18 million to $20 million in additional taxes and interest from January 1, 2003, through December 31, 2007.

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. The parties have agreed to stay this action in order to participate in ongoing mediation.

Certain other royalty matters are currently being litigated by a federal regulatory agency and another Colorado producer. Although we are not a party to the litigation, the final outcome of that case 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.

We sold a natural gas liquids pipeline system in 2002, and in July 2006, the purchaser of that system filed its complaint against us and our subsidiaries in state court in Houston, Texas. The purchaser alleges that we breached certain warranties under the purchase and sale agreement and seeks approximately $18 million in damages and our specific performance under certain guarantees. In 2006, we filed our answer to the purchaser's complaint denying all liability. The trial is scheduled to begin on September 15, 2008, and our prior suit filed against the purchaser in Delaware state court is stayed pending resolution of the Texas case.

At December 31, 2007, 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 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 materially adverse effect upon our future financial position.

Commitments

Commitments for construction and acquisition of property, plant and equipment are approximately $484 million at December 31, 2007.

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Note 16. Accumulated Other Comprehensive Loss

The table below presents changes in the components of *accumulated other comprehensive loss.*

	Income (Loss)							
				Pension Benefits		Other Postretirement Benefits		
	Cash Flow Hedges	Foreign Currency Translation	Minimum Pension Liability	Prior Service Cost	Net Actuarial Gain (Loss)	Prior Service Cost	Net Actuarial Gain	Total
	(Millions)							
Balance at December 31, 2004	$ (308)	$ 69	$ (5)	$ —	$ —	$ —	$ —	$ (244)
2005 Change:								
Pre-income tax amount	(396)	11	1	—	—	—	—	(384)
Income tax benefit (provision)	151	—	—	—	—	—	—	151
Net reclassification into earnings of derivative instrument losses (net of a $111 million income tax benefit)	179	—	—	—	—	—	—	179
	(66)	11	1	—	—	—	—	(54)
Balance at December 31, 2005	(374)	80	(4)	—	—	—	—	(298)
2006 Change:								
Pre-income tax amount	423	(4)	(1)	—	—	—	—	418
Income tax benefit (provision)	(162)	—	—	—	—	—	—	(162)
Net reclassification into earnings of derivative instrument losses (net of a $82 million income tax benefit)	133	—	—	—	—	—	—	133
	394	(4)	(1)	—	—	—	—	389
Adjustment to initially apply SFAS No. 158:								
Pre-income tax amount	—	—	8	(6)	(243)*	(7)	(8)	(256)
Income tax benefit (provision)	—	—	(3)	2	93	3	10	105
	—	—	5	(4)	(150)	(4)	2	(151)
Balance at December 31, 2006	20	76	—	(4)	(150)	(4)	2	(60)
2007 Change:								
Pre-income tax amount	201	53	—	—	68	—	15	337
Income tax benefit (provision)	(77)	—	—	—	(26)	—	(6)	(109)
Net reclassification into earnings of derivative instrument gains (net of a $187 million income tax provision)	(301)**	—	—	—	—	—	—	(301)
Amortization included in net periodic benefit expense	—	—	—	—	19	2	—	21
Income tax benefit (provision) on amortization	—	—	—	—	(8)	(1)	—	(9)
	(177)	53	—	—	53	1	9	(61)
Balance at December 31, 2007	$ (157)	$ 129	$ —	$ (4)	$ (97)	$ (3)	$ 11	$ (121)

* Includes $1 million for the Net Actuarial Loss of an equity method investee.

** Includes a $429 million reclassification into earnings of deferred net hedge gains related to the sale of our power business. (See Note 2.)

Note 17. 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 partnership, Williams Partners L.P., is consolidated within our Midstream segment. (See Note 1.) Other primarily consists of corporate operations.

Performance Measurement

We currently evaluate performance based on *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses*, *depreciation, depletion and amortization*, *equity earnings (losses)* and *loss from investments* including impairments related to investments accounted for under the equity method. The accounting policies of the segments are the same as those described in Note 1. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

Energy commodity hedging by our business units may be done through intercompany derivatives with our Gas Marketing Services segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Gas Marketing Services bears the counterparty performance risks associated with the unrelated third parties in these transactions. Additionally, beginning in the first quarter of 2007, hedges related to Exploration & Production may be entered into directly between Exploration & Production and third parties under its new credit agreement. (See Note 11.) Exploration & Production bears the counterparty performance risks associated with the unrelated third parties in these transactions.

Gas Marketing Services 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. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, and provides services to third parties, such as producers.

External revenues of our Exploration & Production segment includes third-party oil and gas sales, which are more than offset by transportation expenses and royalties due third parties on intersegment sales.

The following geographic area data includes *revenues from external customers* based on product shipment origin and *long-lived assets* based upon physical location.

	United States	Other (Millions)	Total
Revenues from external customers:			
2007	$ 10,137	$ 421	$ 10,558
2006	8,982	394	9,376
2005	9,466	315	9,781
Long-lived assets:			
2007	$ 16,279	$ 713	$ 16,992
2006	14,487	682	15,169
2005	12,667	740	13,407

Our foreign operations are primarily located in Venezuela, Canada, and Argentina. *Long-lived assets* are comprised of property, plant and equipment, goodwill and other intangible assets.

The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income (loss)* as reported in the Consolidated Statement of Income and *other financial information* related to *long-lived assets.*

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
			(Millions)				
2007							
Segment revenues:							
External	$ (95)	$ 1,576	$ 5,142	$ 3,924	$ 11	$ —	$ 10,558
Internal	2,188	34	38	709	15	(2,984)	—
Total revenues	$ 2,093	$ 1,610	$ 5,180	$ 4,633	$ 26	$ (2,984)	$ 10,558
Segment profit (loss)	$ 756	$ 673	$ 1,072	$ (337)	$ (1)	$ —	$ 2,163
Less equity earnings	25	51	61	—	—	—	137
Segment operating income (loss)	$ 731	$ 622	$ 1,011	$ (337)	$ (1)	$ —	2,026
General corporate expenses							(161)
Total operating income							$ 1,865
Other financial information:							
Additions to long-lived assets	$ 1,717	$ 546	$ 610	$ —	$ 27	$ —	$ 2,900
Depreciation, depletion & amortization	$ 535	$ 315	$ 214	$ 7	$ 10	$ —	$ 1,081
2006							
Segment revenues:							
External	$ (189)	$ 1,336	$ 4,094	$ 4,128	$ 7	$ —	$ 9,376
Internal	1,677	12	65	921	20	(2,695)	—
Total revenues	$ 1,488	$ 1,348	$ 4,159	$ 5,049	$ 27	$ (2,695)	$ 9,376
Segment profit (loss)	$ 552	$ 467	$ 675	$ (195)	$ (13)	$ —	$ 1,486
Less equity earnings	22	37	40	—	—	—	99
Segment operating income (loss)	$ 530	$ 430	$ 635	$ (195)	$ (13)	$ —	1,387
General corporate expenses							(132)
Securities litigation settlement and related costs							(167)
Total operating income							$ 1,088
Other financial information:							
Additions to long-lived assets	$ 1,496	$ 913	$ 279	$ 1	$ 18	$ —	$ 2,707
Depreciation, depletion & amortization	$ 360	$ 282	$ 203	$ 7	$ 11	$ —	$ 863
2005							
Segment revenues:							
External	$ (202)	$ 1,395	$ 3,212	$ 5,366	$ 10	$ —	$ 9,781
Internal	1,471	18	79	969	17	(2,554)	—
Total revenues	$ 1,269	$ 1,413	$ 3,291	$ 6,335	$ 27	$ (2,554)	$ 9,781
Segment profit (loss)	$ 587	$ 586	$ 460	$ 9	$ (123)	$ —	$ 1,519
Less:							
Equity earnings (losses)	19	44	27	—	(24)	—	66
Loss from investments	—	—	(22)	—	(87)	—	(109)
Segment operating income (loss)	$ 568	$ 542	$ 455	$ 9	$ (12)	$ —	1,562
General corporate expenses							(145)
Securities litigation settlement and related costs							(9)
Total operating income							$ 1,408
Other financial information:							
Additions to long-lived assets	$ 795	$ 420	$ 133	$ 6	$ 5	$ —	$ 1,359
Depreciation, depletion & amortization	$ 254	$ 267	$ 194	$ 10	$ 12	$ —	$ 737

The following table reflects *total assets* and *equity method investments* by reporting segment.

	Total Assets			Equity Method Investments		
	December 31, 2007	December 31, 2006	December 31, 2005	December 31, 2007	December 31, 2006	December 31, 2005
	(Millions)					
Exploration & Production(1)	$ 8,692	$ 7,851	$ 8,672	$ 72	$ 59	$ 58
Gas Pipeline	8,624	8,332	7,581	483	432	439
Midstream Gas & Liquids	6,604	5,562	4,772	321	323	333
Gas Marketing Services(2)	4,437	5,519	11,464	—	—	—
Other	3,592	3,923	3,571	—	—	1
Eliminations(3)	(7,073)	(7,187)	(10,109)	—	—	—
	24,876	24,000	25,951	876	814	831
Discontinued operations	185	1,402	3,492	—	—	—
Total	$ 25,061	$ 25,402	$ 29,443	$ 876	$ 814	$ 831

(1) The 2006 decrease in Exploration & Production's total assets is due primarily to the fluctuations in derivative assets as a result of the impact of changes in commodity prices on existing derivative contracts. Exploration & Production's derivatives are primarily comprised of intercompany transactions with the Gas Marketing Services segment.

(2) The decrease in Gas Marketing Services' total assets for both 2007 and 2006 is due primarily 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.

(3) The 2006 decrease in Eliminations is due primarily to the fluctuations in the intercompany derivative balances.

Note 18. Subsequent Events

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We will recognize a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. In February 2008, the underwriters also exercised their right to purchase an additional 1.65 million common units at the same price. A subsidiary of ours serves as the general partner of WMZ. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. Upon completion of the transaction, we hold approximately 47.7 percent of the interests in WMZ including the interests of the general partner. In accordance with EITF Issue No. 04-5 (see Note 1), WMZ will continue to be consolidated within our Gas Pipeline segment due to our control through the general partner, which is wholly owned by us.

At December 31, 2007, we held all of Williams Partners L.P.'s seven million subordinated units outstanding. In February 2008, all of these subordinated units were converted into common units due to factors which resulted in the termination of the subordination period. As a result, we will recognize a decrease to minority interest and a corresponding increase to stockholders' equity of approximately $1.2 billion in the first quarter of 2008.

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THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA
(Unaudited)

Summarized quarterly financial data are as follows (millions, except per-share amounts).

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2007				
Revenues	$ 2,368	$ 2,824	$ 2,860	$ 2,506
Costs and operating expenses	1,843	2,180	2,222	1,834
Income from continuing operations	170	243	228	206
Net income	134	433	198	225
Basic earnings per common share:				
Income from continuing operations	.28	.40	.38	.35
Diluted earnings per common share:				
Income from continuing operations	.28	.40	.38	.34
2006				
Revenues	$ 2,387	$ 2,220	$ 2,512	$ 2,257
Costs and operating expenses	1,962	1,777	2,040	1,787
Income (loss) from continuing operations	132	(59)	113	161
Net income (loss)	132	(76)	106	147
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	.22	(.10)	.19	.27
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	.22	(.10)	.19	.26

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to changes in the average number of common shares outstanding and rounding.

Net income for fourth-quarter 2007 includes a $23 million adjustment to increase the tax provision relating to an income tax contingency and the following pre-tax items:

- $156 million mark-to-market loss recognized at Gas Marketing Services on a legacy derivative natural gas sales contract that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in December 2007;
- $20 million accrual for litigation contingencies at Gas Marketing Services (see Note 4);
- $19 million in premiums, fees and expenses related to early debt retirement (see Note 11);
- $12 million of income related to a favorable litigation outcome at Midstream (see Note 4);
- $10 million charge related to an impairment of the Carbonate Trend pipeline at Midstream (see Note 4);
- $9 million charge related to the reserve for certain international receivables at Midstream;
- $6 million net loss, including transaction expenses, related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2).

Net income for third-quarter 2007 includes the following pre-tax items:

- $17 million of expenses related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);
- $12 million of income associated with the payments received for a terminated firm transportation agreement on Northwest Pipeline’s Grays Harbor lateral (see Note 4).

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA — (Continued)
(Unaudited)

Net income for second-quarter 2007 includes the following pre-tax items:

- $429 million gain associated with the reclassification of deferred net hedge gains to earnings related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);
- $111 million impairment of the carrying value of certain derivative contracts related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);
- $17 million of income associated with a change in estimate related to a regulatory liability at Northwest Pipeline (see Note 4);
- $15 million impairment of our Hazelton facility included in discontinued operations (see summarized results of discontinued operations at Note 2);
- $14 million of gains from the sales of cost-based investments (see Note 3);
- $14 million of expenses related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);
- $6 million of income associated with the payments received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral (see Note 4).

Net income for the first-quarter 2007 includes the following pre-tax items:

- $8 million of income due to the reversal of a planned major maintenance accrual at Midstream.

Net income (loss) for fourth-quarter 2006 includes a $40 million reduction to the tax provision associated with a favorable U.S. Tax Court ruling, a $7 million increase to the tax provision associated with an adjustment to deferred income taxes (see Note 5) and the following pre-tax items:

- A $16 million impairment of a Venezuelan cost-based investment at Exploration & Production (see Note 3);
- A $15 million charge associated with an oil purchase contract related to our former Alaska refinery (see summarized results of discontinued operations at Note 2).

Net income (loss) for third-quarter 2006 includes the following pre-tax items:

- $13 million of income due to a reduction of contingent obligations at our former distributive power generation business (see summarized results of discontinued operations at Note 2);
- $11 million of expense related to an adjustment of an accounts payable accrual at Midstream;
- $6 million accrual for a loss contingency related to a former exploration business (see summarized results of discontinued operations at Note 2).

Net income (loss) for second-quarter 2006 includes the following pre-tax items:

- $161 million accrual related to our securities litigation settlement (see Note 15);
- $88 million accrual for Gulf Liquids litigation contingency and associated interest expense at Midstream (see Note 4);
- $19 million accrual for an adverse arbitration award related to our former chemical fertilizer business (see summarized results of discontinued operations at Note 2).

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA — (Continued)
(Unaudited)

Net income (loss) for the first-quarter 2006 includes the following pre-tax items:

- $27 million premium and conversion expenses related to the convertible debenture conversion (see Note 12);
- $24 million gain on sale of certain receivables at Gas Marketing Services;
- $9 million of income related to the settlement of an international contract dispute at Midstream;
- $7 million associated with the reversal of an accrued litigation contingency due to a favorable court ruling and the related accrued interest income at our Gas Pipeline segment.

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(Unaudited)

The following information pertains to our oil and gas producing activities and is presented in accordance with SFAS No. 69, "Disclosures About Oil and Gas Producing Activities." The information is required to be disclosed by geographic region. We have significant oil and gas producing activities primarily in the Rocky Mountain and Mid-continent areas of the United States. Additionally, we have international oil- and gas-producing activities, primarily in Argentina. However, proved reserves and revenues related to international activities are approximately 3.6 percent and 3.1 percent, respectively, of our total international and domestic proved reserves and revenues. The following information relates only to the oil and gas activities in the United States.

Capitalized Costs

	As of December 31,	
	2007	2006
	(Millions)	
Proved properties	$ 6,409	$ 5,027
Unproved properties	542	500
	6,951	5,527
Accumulated depreciation, depletion and amortization and valuation provisions	(1,754)	(1,260)
Net capitalized costs	$ 5,197	$ 4,267

- Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $505 million and $338 million, net, for 2007 and 2006, respectively. The capitalized cost amounts for 2007 and 2006 do not include approximately $1 billion of goodwill related to the purchase of Barrett Resources Corporation (Barrett) in 2001.
- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves; development wells including uncompleted development well costs; and successful exploratory wells.
- Unproved properties consist primarily of acreage related to probable/possible reserves acquired through the Barrett acquisition in 2001. The balance is unproved exploratory acreage.

Costs Incurred

	For the Year Ended December 31,		
	2007	2006	2005
		(Millions)	
Acquisition	$ 82	$ 84	$ 45
Exploration	38	20	8
Development	1,374	1,173	724
	$ 1,494	$ 1,277	$ 777

- Costs incurred include capitalized and expensed items.
- Acquisition costs are as follows: The 2007 cost is primarily for additional land and reserve acquisitions in the Piceance and Fort Worth basins. The 2006 cost is primarily for additional land and reserve acquisitions in the Fort Worth basin. The 2005 costs primarily consist of a land and reserve acquisition in the Fort Worth basin and an additional land acquisition in the Arkoma basin.

- Exploration costs include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes, and the cost of retaining undeveloped leaseholds including lease amortization and impairments.
- Development costs include costs incurred to gain access to and prepare development well locations for drilling and to drill and equip development wells.

Results of Operations

	For the Year Ended December 31,		
	2007	2006	2005
		(Millions)	
Revenues:			
Oil and gas revenues	$ 1,725	$ 1,238	$ 1,072
Other revenues	304	186	144
Total revenues	2,029	1,424	1,216
Costs:			
Production costs	360	309	230
General & administrative	144	111	80
Exploration expenses	21	18	8
Depreciation, depletion & amortization	523	351	245
(Gains)/Losses on sales of interests in oil and gas properties	(1)	—	(31)
Other expenses	270	136	141
Total costs	1,317	925	673
Results of operations	712	499	543
Provision for income taxes	(273)	(174)	(217)
Exploration and production net income	$ 439	$ 325	$ 326

- Results of operations for producing activities consist of all related domestic activities within the Exploration & Production reporting unit. Other expenses in 2005 include a $6 million gain on sales of securities associated with a coal seam royalty trust.
- Oil and gas revenues consist primarily of natural gas production sold to the Gas Marketing Services subsidiary and includes the impact of hedges, including intercompany hedges.
- Other revenues and other expenses consist of activities within the Exploration & Production segment that are not a direct part of the producing activities. These nonproducing activities include acquisition and disposition of other working interest and royalty interest gas and the movement of gas from the wellhead to the tailgate of the respective plants for sale to the Gas Marketing Services subsidiary or third-party purchasers. In addition, other revenues include recognition of income from transactions which transferred certain nonoperating benefits to a third party.
- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include production taxes other than income taxes and administrative expenses in support of production activity. Excluded are depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

- Exploration expenses include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes, and the cost of retaining undeveloped leaseholds including lease amortization and impairments.
- Depreciation, depletion and amortization includes depreciation of support equipment.

Proved Reserves

	2007	2006 (Bcfe)	2005
Proved reserves at beginning of period	3,701	3,382	2,986
Revisions	(106)	(113)	(12)
Purchases	19	41	28
Extensions and discoveries	863	669	615
Production	(334)	(277)	(224)
Sale of minerals in place	—	(1)	(11)
Proved reserves at end of period	4,143	3,701	3,382
Proved developed reserves at end of period	2,252	1,945	1,643

- The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Our proved reserves consist of two categories, proved developed reserves and proved undeveloped reserves. Proved developed reserves are currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or borehole stimulation treatments. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.
- Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit. Crude oil reserves are insignificant and have been included in the proved reserves on a basis of billion cubic feet equivalents (Bcfe).

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is based on the estimated quantities of proved reserves and the year-end prices and costs. The average year-end natural gas prices used in the following estimates were $5.78, $4.81, and $6.95 per MMcfe at December 31, 2007, 2006, and 2005, respectively. Future income tax expenses have been computed considering available carry forwards and credits and the appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by SFAS No. 69. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs. Of the $3,497 million of future development costs, $1,135 million, $1,126 million and $468 million are estimated to be spent in 2008, 2009 and 2010, respectively.

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES — (Continued)
(Unaudited)

Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

Standardized Measure of Discounted Future Net Cash Flows

	At December 31, 2007	2006
	(Millions)	
Future cash inflows	$ 23,937	$ 17,821
Less:		
Future production costs	5,345	5,207
Future development costs	3,497	3,070
Future income tax provisions	5,416	3,350
Future net cash flows	9,679	6,194
Less 10 percent annual discount for estimated timing of cash flows	4,876	3,338
Standardized measure of discounted future net cash flows	$ 4,803	$ 2,856

Sources of Change in Standardized Measure of Discounted Future Net Cash Flows

	2007	2006	2005
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 2,856	$ 5,281	$ 3,147
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,426)	(1,179)	(1,222)
Net change in prices and production costs	2,019	(4,052)	2,358
Extensions, discoveries and improved recovery, less estimated future costs	2,163	647	1,310
Development costs incurred during year	738	881	723
Changes in estimated future development costs	(931)	(1,022)	(300)
Purchase of reserves in place, less estimated future costs	48	63	78
Sales of reserves in place, less estimated future costs	—	(2)	(31)
Revisions of previous quantity estimates	(266)	(140)	(28)
Accretion of discount	434	790	488
Net change in income taxes	(1,108)	1,468	(1,272)
Other	276	121	30
Net changes	1,947	(2,425)	2,134
Standardized measure of discounted future net cash flows end of period	$ 4,803	$ 2,856	$ 5,281

THE WILLIAMS COMPANIES, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	ADDITIONS: Charged to Cost and Expenses	ADDITIONS: Other	Deductions	Ending Balance
			(Millions)		
Year ended December 31, 2007:					
Allowance for doubtful accounts — accounts and notes receivable(a)	$ 15	$ 12	$ —	$ —	$ 27
Deferred tax asset valuation allowance(a)	36	21	—	—	57
Price-risk management credit reserves(a)	7	(6)(e)	—	—	1
Processing plant major maintenance accrual(b)	8	—	—	8(c)	—
Year ended December 31, 2006:					
Allowance for doubtful accounts — accounts and notes receivable(a)	86	4	(66)(f)	9(d)	15
Deferred tax asset valuation allowance(a)	37	(1)	—	—	36
Price-risk management credit reserves(a)	15	(8)(e)	—	—	7
Processing plant major maintenance accrual(b)	7	2	—	1	8
Year ended December 31, 2005:					
Allowance for doubtful accounts — accounts and notes receivable(a)	98	3	—	15(d)	86
Deferred tax asset valuation allowance(a)	62	(25)	—	—	37
Price-risk management credit reserves(a)	3	12(e)	—	—	15
Processing plant major maintenance accrual(b)	6	1	—	—	7

(a) Deducted from related assets.

(b) Included in *accrued liabilities* in 2006 and *other liabilities and deferred income* in 2005.

(c) Effective January 1, 2007, we adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*. As a result, we recognized as other income an $8 million reversal of an accrual for major maintenance on our Geismar ethane cracker. We did not apply the FSP retrospectively because the impact to our 2007 earnings, as well as the impact to prior periods, is not material. We have adopted the deferral method of accounting for these costs going forward.

(d) Represents balances written off, reclassifications, and recoveries.

(e) Included in *revenues.*

(f) During 2006, $66 million in previously reserved Enron receivables were sold.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d – 15(e) of the Securities Exchange Act) (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.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our Disclosure 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 make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

Management's Report on Internal Control over Financial Reporting

See "Management's Report on Internal Control over Financial Reporting" set forth in Item 8, "Financial Statements and Supplementary Data."

Changes in Internal Controls Over Financial Reporting

There have been no changes during the fourth quarter of 2007 that have materially affected, or are reasonably likely to materially affect, our Internal Control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information regarding our directors and nominees for director required by Item 401 of Regulation S-K will be presented under the headings "Board of Directors — Board Committees," and "Election of Directors" in our Proxy Statement prepared for the solicitation of proxies in connection with our Annual Meeting of Stockholders to be held May 15, 2008 (Proxy Statement), which information is incorporated by reference herein.

Information regarding our executive officers required by Item 401(b) of Regulation S-K is presented at the end of Part I herein and captioned "Executive Officers of the Registrant" as permitted by General Instruction G(3) to Form 10-K and Instruction 3 to Item 401(b) of Regulation S-K.

Information required by Item 405 of Regulation S-K will be included under the heading "Compliance with Section 16(a) of the Securities Exchange Act of 1934" in our Proxy Statement, which information is incorporated by reference herein.

Information required by paragraphs (c)(3), (d)(4) and (d)(5) of Item 407 of Regulation S-K will be included under the heading "Corporate Governance" in our Proxy Statement, which information in incorporated by reference herein.

We have adopted a Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, and Controller, or persons performing similar functions. The Code of Ethics, together with our Corporate Governance Guidelines, the charters for each of our board committees, and our Code of Business Conduct applicable to all employees are available on our Internet website at *http://www.williams.com.* We will provide, free of charge, a copy of our Code of Ethics or any of our other corporate documents listed above upon written request to our Secretary at Williams, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Controller, and persons performing similar functions on our Internet website at *http://www.williams.com* under the Investor Relations caption, promptly following the date of any such amendment or waiver.

Item 11. ***Executive Compensation***

The information required by Item 402 and paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K regarding executive compensation will be presented under the headings "Board of Directors," "Executive Compensation," "Compensation committee interlocks and insider participation," and "Compensation committee report" in our Proxy Statement, which information is incorporated by reference herein. Notwithstanding the foregoing, the information provided under the heading "Compensation Committee Report" in our Proxy Statement is furnished and shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information regarding securities authorized for issuance under equity compensation plans required by Item 201(d) of Regulation S-K and the security ownership of certain beneficial owners and management required by Item 403 of Regulation S-K will be presented under the headings "Equity Compensation Stock Plans" and "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement, which information is incorporated by reference herein.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information regarding certain relationships and related transactions required by Item 404 and Item 407(a) of Regulation S-K will be presented under the heading "Certain Relationships and Related Transactions" and "Corporate Governance" in our Proxy Statement, which information is incorporated by reference herein.

Item 14. ***Principal Accounting Fees and Services***

The information regarding our principal accountant fees and services required by Item 9(e) of Schedule 14A will be presented under the heading "Principal Accountant Fees and Services" in our Proxy Statement, which information is incorporated by reference herein.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

(a) 1 and 2.

All other schedules have been omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.

(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

INDEX TO EXHIBITS

Exhibit No.		Description
3.1*	—	Restated Certificate of Incorporation, as supplemented (filed as Exhibit 3.1 to our Form 10-K filed March 11, 2005).
3.2*	—	Restated By-Laws (filed as Exhibit 3.2 to our current report on Form 8-K filed May 22, 2007).
4.1*	—	Form of Senior Debt Indenture between Williams and Bank One Trust company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.1 to our Form S-3 filed September 8, 1997).
4.2*	—	Form of Floating Rate Senior Note (filed as Exhibit 4.3 to our Form S-3 filed September 8, 1997).
4.3*	—	Form of Fixed Rate Senior Note (filed as Exhibit 4.4 to our Form S-3 filed September 8, 1997).
4.4*	—	Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(j) to Form 10-K for the fiscal year ended December 31, 2000).
4.5*	—	Fifth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(k) to our Form 10-K for the fiscal year ended December 31, 2000).
4.6*	—	Seventh Supplemental Indenture dated March 19, 2002, between The Williams Companies, Inc. as Issuer and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to our Form 10-Q filed May 9, 2002).
4.7*	—	Form of Senior Debt Indenture between Williams Holdings of Delaware, Inc. and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Williams Holdings of Delaware, Inc.'s our Form 10-Q filed October 18, 1995).

Exhibit No.		Description
4.8*	—	First Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Citibank, N.A., as Trustee (filed as Exhibit 4(o) to Form 10-K for the fiscal year ended December 31, 1999).
4.9*	—	Senior Indenture dated February 25, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.4.1 to MAPCO Inc.'s Amendment No. 1 to Form S-3 dated February 25, 1997).
4.10*	—	Supplemental Indenture No. 1 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(o) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
4.11*	—	Supplemental Indenture No. 2 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(p) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
4.12*	—	Supplemental Indenture No. 3 dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(j) to Williams Holdings of Delaware, Inc.'s Form 10-K for the fiscal year ended December 31, 1998).
4.13*	—	Supplemental Indenture No. 4 dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(q) to our Form 10-K for the fiscal year ended December 31, 1999).
4.14*	—	Indenture dated as of May 28, 2003, by and between The Williams Companies, Inc. and JPMorgan Chase Bank, as Trustee for the issuance of the 5.50% Junior Subordinated Convertible Debentures due 2033 (filed as Exhibit 4.2 to our Form 10-Q filed August 12, 2003).
4.15*	—	Amended and Restated Rights Agreement dated September 21, 2004 by and between The Williams Companies, Inc. and EquiServe Trust Company, N.A., as Rights Agent (filed as Exhibit 4.1 to our Form 8-K filed September 21, 2004).
4.16*	—	Amendment No. 1 dated May 18, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed as Exhibit 4.1 to our current report on Form 8-K filed May 22, 2007).
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4.19*	—	Indenture dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee, with regard to Northwest Pipeline's $175 million aggregate principal amount of 7.00% Senior Notes due 2016 (filed as Exhibit 4.1 to Northwest Pipeline's Form 8-K dated June 23, 2006).
4.20*	—	Indenture, dated as of April 5, 2007, between Northwest Pipeline Corporation and The Bank of New York (filed as Exhibit 4.1 to Northwest Pipeline Corporation's (Commission File number 001-07414) current report on Form 8-K filed April 5, 2007).
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4.22*	—	Senior Indenture dated as of January 16, 1998 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-3 dated September 8, 1997).
4.23*	—	Indenture dated as of August 27, 2001 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-4 dated November 8, 2001).

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4.24*	—	Indenture dated as of July 3, 2002 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to The Williams Companies Inc.'s Form 10-Q for the quarterly period ended June 30, 2002).
4.25*	—	Indenture dated December 17, 2004 between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K filed December 21, 2004).
4.26*	—	Indenture dated as of April 11, 2006, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee with regard to Transcontinental Gas Pipe Line's $200 million aggregate principal amount of 6.4% Senior Note due 2016 (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K dated April 11, 2006).
4.27*	—	Indenture dated June 20, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and JPMorgan Chase Bank, N.A. (filed as Exhibit 4.1 to Williams Partners L.P. Form 8-K filed June 20, 2006).
4.28*	—	Indenture dated December 13, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and The Bank of New York (filed as Exhibit 4.1 to Williams Partners L.P. filed December 19, 2006).
10.1*	—	The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 1988 (filed as Exhibit 10(iii)(c) to our Form 10-K for the fiscal year ended December 31, 1987).
10.2*	—	First Amendment to The Williams Companies, Inc. Supplemental Retirement Plan effective as of April 1, 1988 (filed as Exhibit 10.2 to our Form 10-K for the fiscal year ended December 31, 2003).
10.3*	—	Second Amendment to The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 2002 and January 1, 2003 (filed as Exhibit 10.3 to our Form 10-K filed March, 11, 2005).
10.4*	—	The Williams Companies, Inc. Stock Plan for Non-Officer Employees (filed as Exhibit 10(iii)(g) to our Form 10-K for the fiscal year ended December 31, 1995).
10.5*	—	The Williams Companies, Inc. 1996 Stock Plan (filed as Exhibit A to our Proxy Statement dated March 27, 1996).
10.6*	—	The Williams Companies, Inc. 1996 Stock Plan for Non-employee Directors (filed as Exhibit B to our Proxy Statement dated March 27, 1996).
10.7*	—	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 10.7 to our Form 10-K for the fiscal year ended December 31, 2006).
10.8*	—	The Williams Companies, Inc. 2002 Incentive Plan for Non-Employee Director Stock Option Agreement (filed as Exhibit 10.8 to our Form 10-K for the fiscal year ended December 31, 2006).
10.9*	—	Indemnification Agreement effective as of August 1, 1986, among Williams, members of the Board of Directors and certain officers of Williams (filed as Exhibit 10(iii)(e) to our Form 10-K for the year ended December 31, 1986).
10.10*	—	Form of 2004 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 10.12 to our Form 10-K filed March 11, 2005).
10.11*	—	Form of 2004 Performance-Based Deferred Stock Agreement among Williams and executive officers (filed as Exhibit 10.13 to our Form 10-K filed March 11, 2005).
10.12*	—	Form of Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 2, 2005).
10.13*	—	Form of 2005 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 2, 2005).
10.14*	—	Form of 2005 Performance-Based Deferred Stock Agreement among Williams and executive officers (filed as Exhibit 99.3 to our Form 8-K filed March 2, 2005).
10.15*	—	Form of 2006 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 7, 2006).

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10.16*	—	Form of 2006 Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 7, 2006).
10.17*	—	Form of 2006 Performance-Based Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our Form 8-K filed March 7, 2006).
10.18*	—	Form of 2007 Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our current report on Form 8-K filed March 1, 2007).
10.19*	—	Form of 2007 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our current report on Form 8-K filed March 1, 2007).
10.20*	—	Form of 2007 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our current report on Form 8-K filed March 1, 2007).
10.21*	—	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 4.1 to our Form S-8 filed August 1, 2001).
10.22*	—	The Williams Companies, Inc. 2002 Incentive Plan as amended and restated effective as of January 23, 2004 (filed as Exhibit 10.1 to our Form 10-Q filed on August 5, 2004).
10.23*	—	The Williams Companies, Inc. 2007 Incentive Plan (filed as Appendix C to our Definitive Proxy Statement 14A filed on April 10, 2007).
10.24*	—	The Williams Companies, Inc. Employee Stock Purchase Plan (filed as Appendix D to our Definitive Proxy Statement 14A filed on April 10, 2007).
10.25*	—	Form of Change in Control Severance Agreement between the Company and certain executive officers (filed as Exhibit 10.12 to our Form 10-Q filed November 14, 2002).
10.26*	—	Settlement Agreement, by and among the Governor of the State of California and the several other parties named therein and The Williams Companies, Inc. and Williams Energy Marketing & Trading Company dated November 11, 2002 (filed as Exhibit 10.79 to our Form 10-K for the fiscal year ended December 31, 2002).
10.27*	—	The Williams Companies, Inc. Severance Pay Plan as Amended and Restated effective October 28, 2003 (filed as Exhibit 10.21 to our Form 10-K for the fiscal year ended December 31, 2005).
10.28*	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated October 28, 2003 (filed as Exhibit 10.22 to our Form 10-K for the fiscal year ended December 31, 2005).
10.29*	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated June 1, 2004 (filed as Exhibit 10.23 to our Form 10-K for the fiscal year ended December 31, 2005).
10.30*	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated January 1, 2005 (filed as Exhibit 10.24 to our Form 10-K for the fiscal year ended December 31, 2005).
10.31*	—	Amendment Agreement, dated May 9, 2007, among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed as Exhibit 10.1 to our current report on Form 8-K filed May 15, 2007).
10.32*	—	Amendment Agreement dated November 21, 2007 among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline GP, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed as Exhibit 10.1 to our Form 8-K filed November 28, 2007).
10.33*	—	Credit Agreement dated as of May 1, 2006, among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and Williams Partners L.P., as Borrowers and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to our form 8-K filed May 1, 2006).
10.34*	—	U.S. $400,000,000 Five Year Credit Agreement dated January 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.3 to our Form 8-K filed on January 26, 2005).

Exhibit No.		Description
10.35*	—	U.S. $100,000,000 Five Year Credit Agreement dated January 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.4 to our Form 8-K filed on January 26, 2005).
10.36*	—	U.S. $500,000,000 Five Year Credit Agreement dated September 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.1 to our Form 8-K filed on September 26, 2005).
10.37*	—	U.S. $200,000,000 Five Year Credit Agreement dated September 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.2 to our Form 8-K filed on September 26, 2005).
10.38*	—	Assumption Agreement dated June 17, 2003 by and between The Williams Companies, Inc. and WEG Acquisitions, L.P. (filed as Exhibit 10.10 to our Form 10-Q filed August 12, 2003).
10.39*	—	Agreement for the Release of Certain Indemnification Obligations dated as of May 26, 2004 by and among Magellan Midstream Holdings, L.P., Magellan G.P. LLC and Magellan Midstream Partners, L.P., on the one hand, and The Williams Companies, Inc., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and Williams GP LLC, on the other hand (filed as Exhibit 10.6 to our Form 10-Q filed August 5, 2004).
10.40*	—	Master Professional Services Agreement dated as of June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation (filed as Exhibit 10.2 to our Form 10-Q filed August 5, 2004).
10.41*	—	Amendment No. 1 to the Master Professional Services Agreement dated June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation made as of June 1, 2004 (filed as Exhibit 10.3 to our Form 10-Q filed August 5, 2004).
10.42*	—	Purchase and Sale Agreement, dated November 16, 2006, by and among Williams Energy Services, LLC, Williams field Services Group, LLC, Williams Field Services Company, LLC Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (incorporated by reference to Exhibit 2.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 1-32599) filed on November 21, 2006) (filed as Exhibit 2.1 to our Form 8-K filed November 22, 2006).
10.43*	—	Credit Agreement dated February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners (filed as Exhibit 10.41 to our Form 10-K for the fiscal year ended December 31, 2006).
10.44*	—	Asset Purchase Agreement between Williams Power Company, Inc. and Bear Energy LP dated May 20, 2007 (filed as Exhibit 99.1 to our current report on Form 8-K filed May 22, 2007).
10.45*	—	Credit Agreement dated as of December 11, 2007, by and among Williams Partners L.P., the lenders party hereto, Citibank, N.A., as Administrative Agent and Issuing Bank, and The Bank of Nova Scotia, as Swingline Lender (filed as Exhibit 10.5 to Williams Partners L.P. Form 8-K filed December 17, 2007).
10.46*	—	Contribution Conveyance and Assumption Agreement, dated January 24, 2008, among Williams Pipeline Partners L.P., Williams Pipeline Operating LLC, WPP Merger LLC, Williams Pipeline Partners Holdings LLC, Northwest Pipeline GP, Williams Pipeline GP LLC, Williams Gas Pipeline Company, LLC, WGPC Holdings LLC and Williams Pipeline Services Company (filed as Exhibit 10.2 to 1 to Williams Pipeline Partners L.P. Form 8-K filed January 30, 2008).
12	—	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.
14*	—	Code of Ethics (filed as Exhibit 14 to Form 10-K for the fiscal year ended December 31, 2003).

Exhibit No.		Description
20*	—	Definitive Proxy Statement of Williams for 2008 (to be filed with the Securities and Exchange Commission on or before April 15, 2008).
21	—	Subsidiaries of the registrant.
23.1	—	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
23.2	—	Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
23.3	—	Consent of Independent Petroleum Engineers and Geologists, Miller and Lents, LTD.
24	—	Power of Attorney together with certified resolution.
31.1	—	Certification of the 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.
31.2	—	Certification of the 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.
32	—	Certification of the Chief Executive Officer and the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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)

By: /s/ BRIAN K. SHORE
Brian K. Shore
Attorney-in-Fact

Date: February 26, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ STEVEN J. MALCOLM* Steven J. Malcolm*	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 26, 2008
/s/ DONALD R. CHAPPEL* Donald R. Chappel*	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2008
/s/ TED T. TIMMERMANS* Ted T. Timmermans*	Controller (Principal Accounting Officer)	February 26, 2008
/s/ KATHLEEN B. COOPER* Kathleen B. Cooper*	Director	February 26, 2008
/s/ IRL F. ENGELHARDT* Irl F. Engelhardt*	Director	February 26, 2008
/s/ WILLIAM R. GRANBERRY* William R. Granberry*	Director	February 26, 2008
/s/ WILLIAM E. GREEN* William E. Green*	Director	February 26, 2008
/s/ JUANITA H. HINSHAW* Juanita H. Hinshaw*	Director	February 26, 2008
/s/ W.R. HOWELL* W.R. Howell*	Director	February 26, 2008
/s/ CHARLES M. LILLIS* Charles M. Lillis*	Director	February 26, 2008

Signature	Title	Date
/s/ GEORGE A. LORCH* George A. Lorch*	Director	February 26, 2008
/s/ WILLIAM G. LOWRIE* William G. Lowrie*	Director	February 26, 2008
/s/ FRANK T. MACINNIS* Frank T. MacInnis*	Director	February 26, 2008
/s/ JANICE D. STONEY* Janice D. Stoney*	Director	February 26, 2008
By: /s/ BRIAN K. SHORE Brian K. Shore *Attorney-in-Fact*		February 26, 2008

INDEX TO EXHIBITS

Exhibit No.		Description
3.1*	—	Restated Certificate of Incorporation, as supplemented (filed as Exhibit 3.1 to our Form 10-K filed March 11, 2005).
3.2*	—	Restated By-Laws (filed as Exhibit 3.2 to our current report on Form 8-K filed May 22, 2007).
4.1*	—	Form of Senior Debt Indenture between Williams and Bank One Trust company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.1 to our Form S-3 filed September 8, 1997).
4.2*	—	Form of Floating Rate Senior Note (filed as Exhibit 4.3 to our Form S-3 filed September 8, 1997).
4.3*	—	Form of Fixed Rate Senior Note (filed as Exhibit 4.4 to our Form S-3 filed September 8, 1997).
4.4*	—	Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(j) to Form 10-K for the fiscal year ended December 31, 2000).
4.5*	—	Fifth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(k) to our Form 10-K for the fiscal year ended December 31, 2000).
4.6*	—	Seventh Supplemental Indenture dated March 19, 2002, between The Williams Companies, Inc. as Issuer and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to our Form 10-Q filed May 9, 2002).
4.7*	—	Form of Senior Debt Indenture between Williams Holdings of Delaware, Inc. and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Williams Holdings of Delaware, Inc.'s our Form 10-Q filed October 18, 1995).
4.8*	—	First Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Citibank, N.A., as Trustee (filed as Exhibit 4(o) to Form 10-K for the fiscal year ended December 31, 1999).
4.9*	—	Senior Indenture dated February 25, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.4.1 to MAPCO Inc.'s Amendment No. 1 to Form S-3 dated February 25, 1997).
4.10*	—	Supplemental Indenture No. 1 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(o) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
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10.23*	—	The Williams Companies, Inc. 2007 Incentive Plan (filed as Appendix C to our Definitive Proxy Statement 14A filed on April 10, 2007).
10.24*	—	The Williams Companies, Inc. Employee Stock Purchase Plan (filed as Appendix D to our Definitive Proxy Statement 14A filed on April 10, 2007).
10.25*	—	Form of Change in Control Severance Agreement between the Company and certain executive officers (filed as Exhibit 10.12 to our Form 10-Q filed November 14, 2002).
10.26*	—	Settlement Agreement, by and among the Governor of the State of California and the several other parties named therein and The Williams Companies, Inc. and Williams Energy Marketing & Trading Company dated November 11, 2002 (filed as Exhibit 10.79 to our Form 10-K for the fiscal year ended December 31, 2002).
10.27*	—	The Williams Companies, Inc. Severance Pay Plan as Amended and Restated effective October 28, 2003 (filed as Exhibit 10.21 to our Form 10-K for the fiscal year ended December 31, 2005).
10.28*	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated October 28, 2003 (filed as Exhibit 10.22 to our Form 10-K for the fiscal year ended December 31, 2005).
10.29*	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated June 1, 2004 (filed as Exhibit 10.23 to our Form 10-K for the fiscal year ended December 31, 2005).
10.30*	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated January 1, 2005 (filed as Exhibit 10.24 to our Form 10-K for the fiscal year ended December 31, 2005).
10.31*	—	Amendment Agreement, dated May 9, 2007, among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed as Exhibit 10.1 to our current report on Form 8-K filed May 15, 2007).

Exhibit No.		Description
10.32*	—	Amendment Agreement dated November 21, 2007 among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline GP, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed as Exhibit 10.1 to our Form 8-K filed November 28, 2007).
10.33*	—	Credit Agreement dated as of May 1, 2006, among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and Williams Partners L.P., as Borrowers and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to our form 8-K filed May 1, 2006).
10.34*	—	U.S. $400,000,000 Five Year Credit Agreement dated January 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.3 to our Form 8-K filed on January 26, 2005).
10.35*	—	U.S. $100,000,000 Five Year Credit Agreement dated January 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.4 to our Form 8-K filed on January 26, 2005).
10.36*	—	U.S. $500,000,000 Five Year Credit Agreement dated September 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.1 to our Form 8-K filed on September 26, 2005).
10.37*	—	U.S. $200,000,000 Five Year Credit Agreement dated September 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.2 to our Form 8-K filed on September 26, 2005).
10.38*	—	Assumption Agreement dated June 17, 2003 by and between The Williams Companies, Inc. and WEG Acquisitions, L.P. (filed as Exhibit 10.10 to our Form 10-Q filed August 12, 2003).
10.39*	—	Agreement for the Release of Certain Indemnification Obligations dated as of May 26, 2004 by and among Magellan Midstream Holdings, L.P., Magellan G.P. LLC and Magellan Midstream Partners, L.P., on the one hand, and The Williams Companies, Inc., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and Williams GP LLC, on the other hand (filed as Exhibit 10.6 to our Form 10-Q filed August 5, 2004).
10.40*	—	Master Professional Services Agreement dated as of June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation (filed as Exhibit 10.2 to our Form 10-Q filed August 5, 2004).
10.41*	—	Amendment No. 1 to the Master Professional Services Agreement dated June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation made as of June 1, 2004 (filed as Exhibit 10.3 to our Form 10-Q filed August 5, 2004).
10.42*	—	Purchase and Sale Agreement, dated November 16, 2006, by and among Williams Energy Services, LLC, Williams field Services Group, LLC, Williams Field Services Company, LLC Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (incorporated by reference to Exhibit 2.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 1-32599) filed on November 21, 2006) (filed as Exhibit 2.1 to our Form 8-K filed November 22, 2006).
10.43*	—	Credit Agreement dated February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners (filed as Exhibit 10.41 to our Form 10-K for the fiscal year ended December 31, 2006).
10.44*	—	Asset Purchase Agreement between Williams Power Company, Inc. and Bear Energy LP dated May 20, 2007 (filed as Exhibit 99.1 to our current report on Form 8-K filed May 22, 2007).
10.45*	—	Credit Agreement dated as of December 11, 2007, by and among Williams Partners L.P., the lenders party hereto, Citibank, N.A., as Administrative Agent and Issuing Bank, and The Bank of Nova Scotia, as Swingline Lender (filed as Exhibit 10.5 to Williams Partners L.P. Form 8-K filed December 17, 2007).

Exhibit No.		Description
10.46*	—	Contribution Conveyance and Assumption Agreement, dated January 24, 2008, among Williams Pipeline Partners L.P., Williams Pipeline Operating LLC, WPP Merger LLC, Williams Pipeline Partners Holdings LLC, Northwest Pipeline GP, Williams Pipeline GP LLC, Williams Gas Pipeline Company, LLC, WGPC Holdings LLC and Williams Pipeline Services Company (filed as Exhibit 10.2 to 1 to Williams Pipeline Partners L.P. Form 8-K filed January 30, 2008).
12	—	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.
14*	—	Code of Ethics (filed as Exhibit 14 to Form 10-K for the fiscal year ended December 31, 2003).
20*	—	Definitive Proxy Statement of Williams for 2008 (to be filed with the Securities and Exchange Commission on or before April 15, 2008).
21	—	Subsidiaries of the registrant.
23.1	—	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
23.2	—	Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
23.3	—	Consent of Independent Petroleum Engineers and Geologists, Miller and Lents, LTD.
24	—	Power of Attorney together with certified resolution.
31.1	—	Certification of the 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.
31.2	—	Certification of the 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.
32	—	Certification of the Chief Executive Officer and the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

The Williams Companies, Inc.
Computation of Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2007	2006	2005	2004	2003
			(Dollars in millions)		
Earnings:					
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	$ 1,371	$ 558	$ 774	$ 299	$ (375)
Minority interest in income and preferred returns of consolidated subsidiaries	90	40	26	21	19
Less: Equity earnings, excluding proportionate share from 50% owned investees and unconsolidated majority-owned investee	(60)	(99)	(66)	(50)	(20)
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles, minority interest in income and preferred returns of consolidated subsidiaries and equity earnings	1,401	499	734	270	(376)
Add:					
Fixed charges:					
Interest accrued, including proportionate share from 50% owned investees and unconsolidated majority-owned investee (a)	709	694	680	822	1,274
Rental expense representative of interest factor	22	16	19	18	25
Preferred distributions	—	—	—	—	48
Total fixed charges	731	710	699	840	1,347
Distributed income of equity-method investees, excluding proportionate share from 50% owned investees and unconsolidated majority-owned investee	48	113	108	61	21
Less:					
Capitalized interest	(32)	(17)	(7)	(7)	(45)
Preferred distributions	—	—	—	—	(48)
Total earnings as adjusted	$ 2,148	$ 1,305	$ 1,534	$ 1,164	$ 899
Fixed charges	$ 731	$ 710	$ 699	$ 840	$ 1,347
Ratio of earnings to fixed charges	2.94	1.84	2.19	1.39	(b)

(a) Does not include interest related to income taxes, including interest related to FIN 48 liabilities, which is included in *provision for income taxes* on our Consolidated Statement of Income. See Note 5 of Notes to Consolidated Financial Statements.

(b) Earnings were inadequate to cover fixed charges by $448 million for the year ended December 31, 2003.

Exhibit 21

ENTITY	JURISDICTION
ACCROVEN SRL	Barbados
Alliance Canada Marketing L.P.	Alberta
Alliance Canada Marketing LTD	Alberta
Apco Argentina, Inc.	Cayman Islands
Apco Argentina, S.A.	Argentina
Apco Properties Ltd.	Cayman Islands
Arctic Fox Assets, Inc.	Delaware
Aspen Products Pipeline LLC	Delaware
Aux Sable Canada Ltd.	Alberta
Aux Sable Canada LP	Alberta
Aux Sable Liquid Products Inc.	Delaware
Aux Sable Liquid Products LP	Alberta
Bargath Inc.	Colorado
Barrett Fuels Corporation	Delaware
Barrett Resources International Corporation	Delaware
Baton Rouge Fractionators LLC	Delaware
Baton Rouge Pipeline LLC	Delaware
Beech Grove Processing Company	Tennessee
Bison Royalty LLC	Delaware
Black Marlin Pipeline Company	Texas
Carbon County UCG, Inc.	Delaware
Carbonate Trend Pipeline LLC	Delaware
Cardinal Operating Company	Delaware
Cardinal Pipeline Company, LLC	North Carolina
Castle Associates, L.P.	Delaware
ChoiceSeat, L.L.C.	Delaware
Diamond Elk, LLC	Colorado
Discovery Gas Transmission LLC	Delaware
Discovery Producer Services LLC	Delaware
Distributed Power Solutions L.L.C.	Delaware
E-Birchtree, LLC	Delaware
Eagle Gas Services, Inc.	Ohio
ESPAGAS USA, Inc.	Delaware
F T & T, Inc.	Delaware
Fishhawk Ranch, Inc.	Florida
FleetOne Inc.	Delaware
Fort Union Gas Gathering, L.L.C.	Delaware
Garrison, L.L.C.	Delaware
Goebel Gathering Company, L.L.C.	Delaware
Gulf Liquids Holdings LLC	Delaware
Gulf Liquids New River Project LLC	Delaware

Gulf Star Deepwater Services, LLC	Delaware
Gulfstream Management & Operating Services, L.L.C.	Delaware
Gulfstream Natural Gas System, L.L.C.	Delaware
Hazleton Fuel Management Company	Delaware
Hazleton Pipeline Company	Delaware
HI-BOL Pipeline Company	Delaware
Inland Ports, Inc.	Tennessee
Kiowa Gas Storage, L.L.C.	Delaware
Laughton, L.L.C.	Delaware
Liberty Operating Company	Delaware
Longhorn Enterprises of Texas, Inc.	Delaware
MAPCO Alaska Inc.	Alaska
MAPCO Inc.	Delaware
MAPL Investments, Inc.	Delaware
Marsh Resources, Inc.	Delaware
Mid-Continent Fractionation and Storage, LLC	Delaware
Millennium Energy Fund, L.L.C.	Delaware
Mockingbird Pipeline, L.P.	Delaware
Northwest Argentina Corporation	Utah
Northwest Land Company	Delaware
Northwest Pipeline GP	Delaware
Northwest Pipeline Services LLC	Delaware
Pacific Connector Gas Pipeline, LLC	Delaware
Pacific Connector Gas Pipeline, LP	Delaware
Parachute Pipeline LLC	Delaware
Parkco Two, L.L.C.	Oklahoma
Pine Needle LNG Company, LLC	North Carolina
Pine Needle Operating Company	Delaware
Rainbow Resources, Inc.	Colorado
Reserveco Inc.	Delaware
Snow Goose Associates, L.L.C.	Delaware
Sociedad Williams Enbridge y Compania	Venezuela
SPV, L.L.C.	Oklahoma
TXG Gas Marketing Company	Delaware
Tennessee Processing Company	Delaware
The Tennessee Coal Company	Delaware
The Williams Companies, International Holdings B.V.	Dutch BV
Thermogas Energy, LLC	Delaware
Touchstar Energy Technologies, Inc.	Texas
Touchstar Technologies Pty Ltd.	South Africa
TransCardinal Company	Delaware
TransCarolina LNG Company	Delaware
Transco Coal Gas Company	Delaware
Transco Energy Company	Delaware
Transco Exploration Company	Delaware
Transco Gas Company	Delaware

Transco Liberty Pipeline Company	Delaware
Transco P-S Company	Delaware
Transco Resources, Inc.	Delaware
Transco Services LLC	Delaware
Transcontinental Gas Pipe Line Corporation	Delaware
Transeastern Gas Pipeline Company, Inc.	Delaware
Tulsa Williams Company	Delaware
Valley View Coal, Inc.	Tennessee
Volunteer — Williams, L.L.C.	Delaware
WEM&T Trading GmbH	Austria
WFS — Liquids Company	Delaware
WFS — Pipeline Company	Delaware
WFS Enterprises, Inc.	Delaware
WFS Gathering Company, L.L.C.	Delaware
WGP Development, LLC	Delaware
WGP Enterprises, Inc.	Delaware
WGP Gulfstream Pipeline Company, L.L.C.	Delaware
WGP International Canada, Inc.	New Brunswick
WGPC Holdings LLC	Delaware
WPX Enterprises, Inc.	Delaware
WPX Gas Resources Company	Delaware
Wamsutter LLC	Delaware
Williams Acquisition Holding Company, Inc. (Del)	Delaware
Williams Acquisition Holding Company, Inc. (NJ)	New Jersey
Williams Acquisition Holding Company LLC	Delaware
Williams Aircraft, Inc.	Delaware
Williams Alaska Petroleum, Inc.	Alaska
Williams Alliance Canada Marketing, Inc.	New Brunswick
Williams Arkoma Gathering Company, LLC	Delaware
Williams Barnett Gathering System, LP	Texas
Williams Cove Point, Inc.	Delaware
Williams Discovery Pipeline, LLC	Delaware
Williams Distributed Power Services, Inc.	Delaware
Williams Energy Canada, Inc.	New Brunswick
Williams Energy European Services Ltd.	United Kingdom
Williams Energy Marketing & Trading Canada, Inc.	New Brunswick
Williams Energy Marketing & Trading Europe Ltd	England
Williams Energy Marketing & Trading Holdings UK Ltd.	United Kingdom
Williams Energy Services, LLC	Delaware
Williams Energy Solutions, Inc.	Delaware
Williams Energy, L.L.C.	Delaware
Williams Equities, Inc.	Delaware
Williams Exploration Company	Delaware
Williams Express, Inc. (AK)	Alaska
Williams Express, Inc.	Delaware
Williams Fertilizer, Inc.	Delaware

Williams Field Services — Gulf Coast Company, L.P.	Delaware
Williams Field Services Company, LLC	Delaware
Williams Field Services Group, LLC	Delaware
Williams Flexible Generation, LLC	Delaware
Williams Four Corners, LLC	Delaware
Williams GP LLC	Delaware
Williams Gas Pipeline Company, LLC	Delaware
Williams Gas Processing — Gulf Coast Company, L.P.	Delaware
Williams Generation Company — Hazleton	Delaware
Williams Global Energy Cayman Limited	Cayman Islands
Williams Global Holdings Company	Delaware
Williams GmbH	Austria
Williams Gulf Coast Gathering Company, LLC	Delaware
Williams Headquarters Building Company	Delaware
Williams Headquarters Building, L.L.C.	Delaware
Williams Holdings GmbH	Austria
Williams Indonesia, L.L.C.	Delaware
Williams Information Technology, Inc.	Delaware
Williams International Bermuda Limited	Bermuda
Williams International Company	Delaware
Williams International El Furrial Limited	Cayman Islands
Williams International Investments Cayman Limited	Cayman Islands
Williams International Jose Limited	Cayman Islands
Williams International Oil & Gas Venezuela Limited	Cayman Islands
Williams International Pigap Limited	Cayman Islands
Williams International Services Company	Nevada
Williams International Telecom Limited	Delaware
Williams International Telecommunications	Cayman Islands
Williams International Venezuela Limited	Cayman Islands
Williams Learning Center, Inc.	Delaware
Williams Longhorn Holdings, LLC	Delaware
Williams Memphis Terminal, Inc.	Delaware
Williams Merchant Services Company, Inc.	Delaware
Williams Mid-South Pipelines, LLC	Delaware
Williams Midstream Marketing and Risk Management, LLC	Delaware
Williams Midstream Natural Gas Liquids, Inc.	Delaware
Williams Mobile Bay Producer Services, L.L.C.	Delaware
Williamd NGL Marketing, LLC	Delaware
Williams Natural Gas Liquids Canada, Inc.	Alberta
Williams Natural Gas Liquids, Inc.	Delaware
Williams New Soda, Inc.	Delaware
Williams Oil Gathering, L.L.C.	Delaware
Williams Olefins Feedstock Pipelines, L.L.C.	Delaware
Williams Olefins, L.L.C.	Delaware
Williams One-Call Services, Inc.	Delaware
Williams Pacific Connector Gas Operator, LLC	Delaware

Williams Pacific Connector Gas Pipeline, LLC	Delaware
Williams Partners Finance Corporation	Delaware
Williams Partners GP LLC	Delaware
Williams Partners Holdings LLC	Delaware
Williams Partners, L.P.	Delaware
Williams Partners Operating LLC	Delaware
Williams PERK, LLC	
WILLIAMS PETROLEOS ESPAÑA, S.L.	Spain
Williams Petroleum Pipeline Systems, Inc.	Delaware
Williams Petroleum Services, LLC	Delaware
Williams Pipeline GP LLC	Delaware
Williams Pipeline Operating LLC	Delaware
Williams Pipeline Partners Holdings LLC	Delaware
Williams Pipeline Partners L.P.	Delaware
Williams Pipeline Services Company	Delaware
Williams Production — Gulf Coast Company, L.P.	Delaware
Williams Production Company, LLC	Delaware
Williams Production Holdings LLC	Delaware
Williams Production Mid-Continent Company	Oklahoma
Williams Production RMT Company	Delaware
Williams Production Rocky Mountain Company	Delaware
Williams Refining & Marketing, L.L.C.	Delaware
Williams Relocation Management, Inc.	Delaware
Williams Resource Center, L.L.C.	Delaware
Williams Soda Holdings, LLC	Delaware
Williams Sodium Products Company	Delaware
Williams Strategic Sourcing Company	Delaware
Williams TravelCenters, Inc.	Delaware
Williams Underground Gas Storage Company	Delaware
Williams WPC — I, Inc.	Delaware
Williams WPC — II, Inc.	Delaware
Williams WPC International Company	Delaware
Williams Western Holding Company, Inc.	Delaware
WilPro Energy Services El Furrial Limited	Cayman Islands
WilPro Energy Services Pigap II Limited	Cayman Islands

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following registration statements on Form S-3 and Form S-4, and related prospectuses of The Williams Companies, Inc. and in the following registration statements on Form S-8 of our reports dated February 22, 2008, with respect to the consolidated financial statements and schedule of The Williams Companies, Inc. and the effectiveness of internal control over financial reporting of The Williams Companies, Inc., included in this Annual Report (Form 10-K) for the year ended December 31, 2007:

Form S-3:
Registration Statement Nos. 333-20927, 333-20929, 333-29185, 333-35097, 333-70394, 333-85540, 333-106504, and 333-134293

Form S-4:
Registration Statement No. 333-129779

Form S-8:
Registration No. 33-58671 - The Williams Companies, Inc. Stock Plan for Nonofficer Employees

Registration No. 33-58971 - Transco Energy Company Thrift Plan

Registration No. 333-03957 - The Williams Companies, Inc. 1996 Stock Plan for Non-Employee Directors

Registration No. 333-11151 - The Williams Companies, Inc. 1996 Stock Plan

Registration No. 333-40721 - The Williams Companies, Inc. 1996 Stock Plan for Nonofficer Employees

Registration No. 333-51994 - The Williams Companies, Inc. 1996 Stock Plan for Nonofficer Employees

Registration No. 333-66474 - The Williams Companies, Inc. 2001 Stock Plan

Registration No. 333-76929 - The Williams International Stock Plan

Registration No. 333-85542 - The Williams Investment Plus Plan

Registration No. 333-85546 - The Williams Companies, Inc. 2002 Incentive Plan

Registration No. 333-142985 - The Williams Companies, Inc. Employee Stock Purchase Plan

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2008

NSA Netherland, Sewell
& Associates, Inc.

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference to our audit letters as of December 31, 2007, each of which is included in the Annual Report on Form 10-K of The Williams Companies for the year ended December 31, 2007. We also consent to the reference to us as experts in such Annual Report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. Scott Rees, III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 18 2008

Exhibit 23.3

Miller and Lents, Ltd.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference to our reserve reports dated as of December 31, 2007, 2006, and 2005, each of which is included in the Annual Report on Form 10-K of The Williams Companies for the year ended December 31, 2007. We also consent to the reference to us under the heading of “Experts” in such Annual Report.

MILLER AND LENTS, LTD.

By /s/ Stephen M. Hamburg
Stephen M. Hamburg
Vice President

February 12, 2008

EXHIBIT 24

THE WILLIAMS COMPANIES, INC.

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that each of the undersigned individuals, in their capacity as a director or officer, or both, as hereinafter set forth below their signature, of THE WILLIAMS COMPANIES, INC., a Delaware corporation ("Williams"), does hereby constitute and appoint JAMES J. BENDER and BRIAN K. SHORE their true and lawful attorneys and each of them (with full power to act without the others) their true and lawful attorneys for them and in their name and in their capacity as a director or officer, or both, of Williams, as hereinafter set forth below their signature, to sign Williams' Annual Report to the Securities and Exchange Commission on Form 10-K for the fiscal year ended December 31, 2007, and any and all amendments thereto or all instruments necessary or incidental in connection therewith; and

THAT the undersigned Williams does hereby constitute and appoint JAMES J. BENDER and BRIAN K. SHORE its true and lawful attorneys and each of them (with full power to act without the others) its true and lawful attorney for it and in its name and on its behalf to sign said Form 10-K and any and all amendments thereto and any and all instruments necessary or incidental in connection therewith.

Each of said attorneys shall have full power of substitution and resubstitution, and said attorneys or any of them or any substitute appointed by any of them hereunder shall have full power and authority to do and perform in the name and on behalf of each of the undersigned, in any and all capacities, every act whatsoever requisite or necessary to be done in the premises, as fully to all intents and purposes as each of the undersigned might or could do in person, the undersigned hereby ratifying and approving the acts of said attorneys or any of them or of any such substitute pursuant hereto.

IN WITNESS WHEREOF, the undersigned have executed this instrument, all as of the 25th day of January, 2008.

/s/ Steven J. Malcolm	/s/ Donald R. Chappel
Steven J. Malcolm Chairman of the Board President and Chief Executive Officer (Principal Executive Officer)	Donald R. Chappel Senior Vice President and Chief Financial Officer (Principal Financial Officer) (Principal Accounting Officer)

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

/s/Kathleen B. Cooper	/s/ Irl F. Engelhardt
Kathleen B. Cooper Director	Irl F. Engelhardt Director
/s/ William R. Granberry	/s/ William E. Green
William R. Granberry Director	William E. Green Director
/s/ Juanita H. Hinshaw	/s/ W. R. Howell
Juanita H. Hinshaw Director	W. R. Howell Director
/s/ Charles M. Lillis	/s/ George A. Lorch
Charles M. Lillis Director	George A. Lorch Director
/s/ William G. Lowrie	/s/ Frank T. MacInnis
William G. Lowrie Director	Frank T. MacInnis Director
/s/ Janice D. Stoney	
Janice D. Stoney Director	

THE WILLIAMS COMPANIES, INC.

By: /s/ James J. Bender
James J. Bender
Senior Vice President

ATTEST

/s/ Brian K. Shore
Brian K. Shore
Secretary

THE WILLIAMS COMPANIES, INC.

Secretary's Certificate

I, the undersigned, BRIAN K. SHORE, Secretary of THE WILLIAMS COMPANIES, INC., a Delaware corporation (hereinafter called the "Company"), do hereby certify that at a regular meeting of the Board of Directors of the Company, duly convened and held on January 24, 2008 at which a quorum of said Board was present and acting throughout, the following resolutions were duly adopted:

> RESOLVED that the Chairman of the Board, the President, any Senior Vice President and the Controller of the Company be, and each of them hereby is, authorized and empowered to execute a Power of Attorney for use in connection with the execution and filing for and on behalf of the Company, under the Securities Exchange Act of 1934, of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the corporate seal of The Williams Companies, Inc. this 24th day of January, 2008.

/s/ Brian K. Shore
Brian K. Shore
Secretary

[S E A L]

Exhibit 31.1

SECTION 302 CERTIFICATION

I, Steven J. Malcolm, certify that:

1. I have reviewed this annual report on Form 10-K of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2008

/s/ Steven J. Malcolm
Steven J. Malcolm
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

SECTION 302 CERTIFICATION

I, Donald R. Chappel, certify that:

1. I have reviewed this annual report on Form 10-K of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2008

/s/ Donald R. Chappel

Donald R. Chappel
Senior Vice President
and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of The Williams Companies, Inc. (the “Company”) on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned hereby certifies, in his capacity as an officer of the Company, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven J. Malcolm

Steven J. Malcolm
Chief Executive Officer
February 26, 2008

/s/ Donald R. Chappel

Donald R. Chappel
Chief Financial Officer
February 26, 2008

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.