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, 2005

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 1-4174

The Williams Companies, Inc.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**73-0569878**
(State or Other Jurisdiction of Incorporation or Organization)	*(IRS Employer Identification No.)*
One Williams Center, Tulsa, Oklahoma	**74172**
(Address of Principal Executive Offices)	*(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 and Pacific Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange and Pacific 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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated filer o Non-accelerated filer 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 $10,857,696,528.

The number of shares outstanding of the registrant's common stock outstanding at February 28, 2006 was 594,655,307.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Annual Meeting of Stockholders to be held May 18, 2006 (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.

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.

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. We also manage a wholesale power business. Our operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Southern California and Eastern Seaboard.

In 2005 our growth opportunities continued to expand. We are expanding our natural gas pipelines to meet market demand, continuing to expand our Exploration & Production drilling program and continuing to pursue Midstream growth opportunities especially in the deepwater Gulf of Mexico.

We continue to use Economic Value Added® (EVA®)[1] as the basis for disciplined decision making around investments for growth. EVA® is a tool that considers both financial earnings and cost of capital in measuring performance. We look for growth opportunities that provide positive EVA® because we believe that there is a strong correlation between EVA® and creation of sustainable value.

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

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

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2005 HIGHLIGHTS

We entered 2005 having completed the key components of our restructuring plan and in a position to shift our focus to growth. Our 2005 plan included the following objectives:

- Increase focus and disciplined EVA®-based investment in natural gas businesses;
- Continue to steadily improve credit ratios and rating with the goal of achieving investment grade ratios;
- Continue to reduce risk and liquidity requirements while maximizing cash flow in the Power segment;
- Maintain liquidity from cash and revolving credit facilities of at least $1 billion;
- Generate sustainable growth in EVA® and shareholder value.

Our 2005 income from continuing operations increased to $317.4 million, as compared to $93.2 million in 2004. Our 2005 results reflect the benefit of increased natural gas production and higher net realized average prices, along with reduced levels of interest expense. Results for 2004 included $282.1 million in costs associated with the early retirement of debt, while results for 2005 were reduced by accruals associated with agreements to resolve gas reporting issues and impairments of certain investments. Our net cash provided by operating activities was $1.45 billion in 2005, comparable with the 2004 level of $1.49 billion. See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for further discussion of our 2005 performance. In addition to achieving these results, the following represent significant actions or events that occurred during the year:

- In 2005, we further improved our credit ratios from those achieved in 2004. We retired $200 million of debt that matured January 15, 2005. On February 16, the holders of the remaining 10.9 million equity forward contracts associated with the FELINE PACS units exercised contracts to purchase one share of our common stock for $25 a share, resulting in cash proceeds of approximately $273 million. The remaining notes associated with the FELINE PACS units totaling approximately $73 million are due February 16, 2007.
- During 2005, Exploration & Production increased its average daily domestic production levels, its net realized average prices, and its developmental drilling activities. In March 2005, Exploration & Production entered into a lease for ten new drilling rigs to support the accelerated pace of natural gas development in the Piceance basin. The first rig was delivered in January 2006 and the remaining rigs are expected to be delivered during 2006.
- In 2005 and early 2006, Power continued to reduce risk by entering into electricity and capacity forward contracts with fixed sales prices for over 6,000 megawatts of capacity in total across various periods through 2010.
- During 2005, Midstream Gas & Liquids (Midstream) continued efforts to expand operations of large scale assets in growth basins. These efforts include signing definitive agreements to extend oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect and obtaining Board approval to add a fifth cryogenic train to our gas processing plant in Opal, Wyoming. Both of these additions are expected to be in service in 2007.
- In July and November of 2005, our Board of Directors approved regular quarterly dividends of 7.5 cents per share of common stock, which reflects an increase of 50 percent compared with the 5 cents per share paid in each of the three prior quarters.
- On August 23, 2005, Williams Partners L.P. completed its initial public offering of five million common units at a price of $21.50 per unit. The underwriters also fully exercised their option to purchase an additional 750,000 common units at the same price. Upon completion of the transaction, we held approximately 60 percent of the interests in Williams Partners L.P., including

100 percent of the general partner. See the Midstream Gas & Liquids Overview of 2005 within Item 7 for further information.

- During third-quarter 2005, certain Gulf Coast area operations were interrupted by hurricanes. The impact of these hurricanes included temporary shutdowns as well as varying levels of damage. The overall impact was not material to our financial position.
- In September 2005, we reached an agreement to settle litigation filed in 2002 under the Employee Retirement Income Security Act (ERISA). The settlement, which received final approval in November 2005, provided for us to pay $55 million to plaintiffs, of which $50 million was covered and paid by insurance. See Note 15 of Notes to Consolidated Financial Statements for further information.
- In September 2005, we increased our available liquidity by obtaining a total of $700 million of capacity in two five-year unsecured credit facilities. See Note 11 of Notes to Consolidated Financial Statements for further information.
- In November 2005, we initiated an offer to induce conversion of up to $300 million of the 5.5 percent junior subordinated debentures convertible into our common stock. The conversion was executed in January 2006 and approximately $220.2 million of the debentures were exchanged for common stock. See Note 12 of Notes to Consolidated Financial Statements for further information.
- During 2005 we continued our efforts to resolve legacy issues, such as pending claims and investigations involving inaccurate reporting of natural gas prices and volumes to an industry publication in 2002. In February 2006, we reached agreements with various parties to substantially resolve this exposure. Under the terms of these agreements, Power will pay a total of $77.2 million to the various parties. See Note 15 of Notes to Consolidated Financial Statements for further information.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 18 of our Notes to Consolidated Financial Statements for information with respect to each segment's revenues, profits or losses and total assets.

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:

- *Power* — manages our wholesale power and natural gas commodity businesses through purchases, sales and other related transactions, under our wholly owned subsidiary Williams Power Company, Inc. and its subsidiaries.
- *Gas Pipeline* — includes our interstate natural gas pipelines and pipeline joint venture investments organized under our wholly owned subsidiary, Williams Gas Pipeline Company, LLC.
- *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.
- *Midstream* — 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 Williams Partners L.P., our master limited partnership formed in 2005.

- *Other* — consists of corporate operations and certain continuing operations previously reported within the International and Petroleum Services segments. 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.

Power

Our Power business buys, sells, stores and transports energy and energy-related commodities, primarily power and natural gas. Since our September 2004 decision to continue operating the power business and cease efforts to exit that business Power has focused not only on its objective of maximizing expected cash flows, but also on executing new contracts to hedge its portfolio and providing functions that support our natural gas businesses. Our contracts include physical forward purchases and sales, various financial instruments and structured transactions. Our financial instruments include exchange-traded futures, as well as exchange-traded and over-the-counter options and swaps. Structured transactions include tolling contracts, full requirements contracts, tolling resales and heat rate options.

Tolling contracts represent the most significant portion of our portfolio. Under the tolling contracts, we have the right to request a plant owner to convert our fuel (usually natural gas) to electricity in exchange for a fixed fee. We have the right to request approximately 7,400 megawatts of electricity under six tolling agreements. The table below lists the locations and available capacity of each of our tolling agreements. These capacity numbers are subject to change, and our contractual rights to capacity may not reflect actual availability at the plants.

Location	Megawatts
California	3,783
Alabama	844
Louisiana	751
New Jersey	766
Pennsylvania	669
Michigan	545
Total	**7,358**

We use portions of the electricity produced under the tolling agreements to supply obligations under various arrangements such as power sales, tolling resales, and full requirements contracts. Under full requirements contracts, we supply the electricity required by our counterparties to serve their customers. Through full requirements contracts, we supply approximately 1,900 megawatts of electricity to our customers in Georgia and Pennsylvania.

Through tolling resale agreements, we enter into transactions that mirror, to varying degrees, some or all of our rights under our underlying tolling arrangements, which remain in place with our tolling counterparties. We have resold part of our rights (2,568 to 3,236 megawatts) under the California tolling arrangement to two counterparties for periods through 2010.

We also own two natural gas-fired electric generating plants located near Bloomfield, New Mexico (60 megawatts, Milagro facility) and in Hazleton, Pennsylvania (147 megawatts).

In 2005, we managed natural gas throughout North America with total physical volumes averaging 2.3 billion cubic feet per day. We use approximately 10 percent of this natural gas to fuel electric generating plants we own or in which we have contractual rights. We sell approximately 70 percent of this natural gas to customers including local distribution companies, utilities, producers, industrials and other gas marketers. With the remaining 20 percent, we procure gas supply for our Midstream operations.

In 2004, we substantially exited our crude oil and refined products activities.

In 2003, we substantially exited our European activities.

Operating statistics

The following table summarizes marketing and trading gross sales volumes, including sales volumes to other segments, for the periods indicated:

	Year Ending December 31,		
	2005	2004	2003
U.S. Operations			
Marketing and trading physical volumes:			
Power (thousand megawatt hours)	66,779	93,998	165,908
Natural gas (billion cubic feet per day)	2.1	2.3	2.7
Petroleum products (thousand barrels per day)	50	50	77

In 2005, Power managed 2.3 billion cubic feet per day of natural gas. The natural gas volumes managed include the following (in billion cubic feet per day):

	2005
Sales to third parties	1.7
Sales to other segments	.4
For use in tolling agreements and by owned generation	.2
Total natural gas managed	2.3

As of December 31, 2005, Power had approximately 300 customers compared with 284 customers at the end of 2004.

Gas Pipeline

We own and operate, through Williams Gas Pipeline Company, LLC and its subsidiaries, a combined total of approximately 14,600 miles of pipelines with a total annual throughput of approximately 2,600 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 Corporation. 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.

Transcontinental Gas Pipe Line Corporation (Transco)

Transco is an interstate natural gas transportation company that owns and operates a 10,500-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 eleven southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, New York, New Jersey, and Pennsylvania. Effective May 1, 1995, Transco transferred the operation of certain production area facilities to Williams Field Services Group LLC (Williams Field Services), an affiliated company and part of the Midstream segment. Effective June 1, 2004 and due in part to Federal Energy Regulatory Commission (FERC) Order No. 2004, the operation of the production area facilities was transferred back to Transco.

Pipeline system and customers

At December 31, 2005, 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 3.5 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.2 MMdt of natural gas per day. Transco's system includes 44 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 10 percent of Transco's total revenues in 2005. 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 four 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

Central New Jersey Expansion Project

The Central New Jersey Expansion Project, an expansion of Transco's existing natural gas transmission system in Transco's Zone 6 from the Station 210 pooling point to a new delivery point on Transco's Trenton-Woodbury Line, was placed into service on November 1, 2005. The project adds 105 Mdt/d of new firm transportation capacity, which has been fully subscribed by one shipper for a twenty-year primary term. The project facilities included approximately 3.8 miles of pipeline loop. The estimated capital cost of the project is approximately $16 million.

Leidy to Long Island Expansion Project

The Leidy to Long Island Expansion Project will involve an expansion of Transco's existing natural gas transmission system in Zone 6 from the Leidy Hub in Pennsylvania to Long Island, New York. The project will provide 100 Mdt/d of incremental firm transportation capacity, which has been fully subscribed by one shipper for a twenty-year primary term. The project facilities will include pipeline looping in Pennsylvania and pipeline looping, uprating and replacement and a natural gas compressor facility in New Jersey. The estimated capital cost of the project is approximately $121 million. We expect that over three-quarters of the project expenditures will occur in 2007. We filed an application for FERC approval of the project in December 2005. The target in-service date for the project is November 1, 2007.

Potomac Expansion Project

Transco held an "open season" from July 19 through August 17, 2005 to receive requests from potential shippers for new firm transportation capacity to be made available on the Transco pipeline system from receipt points in North Carolina to delivery points in the greater Washington, D.C. metropolitan area under Transco's proposed Potomac Expansion Project. As a result of the open season, the expansion is being designed to create 165 Mdt/d of incremental firm transportation capacity, which has been fully subscribed by shippers under long-term firm arrangements. The estimated capital cost of the project is approximately $73 million. Transco filed a request for pre-filing review with the FERC on November 10, 2005. The FERC granted the request on November 17, 2005. Transco plans to file an application for FERC approval of the project during the third quarter of 2006. The target in-service date for the project is November 1, 2007.

Sentinel Expansion Project

Transco held an open season from October 31 through December 2, 2005 to receive requests from potential shippers for new firm transportation capacity to be made available on the Transco pipeline system under Transco's proposed Sentinel Expansion Project. During the open season, we received requests for a total of 256 Mdt/d of incremental firm transportation capacity from the Leidy Hub in Clinton County, Pennsylvania and/or the Pleasant Valley Interconnection with Cove Point LNG, LP in Fairfax County, Virginia to various delivery points requested by the shippers. Transco is evaluating the facilities required to support such requested capacity. The final project size, location of facilities and capital cost will depend on the outcome of that evaluation and the level of firm market commitment confirmed with the requesting parties. The proposed in-service date for the project is November 1, 2008.

Operating statistics

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

	2005	2004 (In trillion British Thermal Units)	2003
Market-area deliveries:			
Long-haul transportation	755	782	771
Market-area transportation	853	817	802
Total market-area deliveries	1,608	1,599	1,573
Production-area transportation	278	317	297
Total system deliveries	1,886	1,916	1,870
Average Daily Transportation Volumes	5.2	5.2	5.1
Average Daily Firm Reserved Capacity	6.6	6.6	6.5

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 Corporation (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, 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, 2005, 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 4,100 miles of mainline and lateral transmission pipelines and 42 transmission compressor stations having a combined sea level-rated capacity of approximately 462,000 horsepower.

In December 2003, we received an Amended Corrective Action Order (ACAO) from the Office of Pipeline Safety (OPS) regarding a segment of one of our natural gas pipelines in western Washington. The pipeline experienced two breaks in 2003 and we subsequently idled the pipeline segment until its integrity could be assured.

By June 2004 we had successfully completed our hydrostatic testing program and returned to service 111 miles of the 268 miles of pipe affected by the ACAO. That effort has restored 131 Mdt/d of the 360 Mdt/d of idled capacity and is anticipated to be adequate to meet most market conditions. To date our ability to serve the market demand has not been significantly impacted.

The restored facilities will be monitored and tested as necessary until they are ultimately replaced in 2006. Through December 31, 2005, approximately $43.3 million has been spent on testing and remediation costs, including approximately $8.9 million related to one segment of pipe that we determined not to return to service and was therefore written off in the second quarter of 2004.

As required by OPS, we plan to replace all capacity associated with the segment affected by the ACAO by November 2006 to meet long-term demands. We conducted a reverse open season to determine whether any existing customers were willing to relinquish or reduce their capacity commitments to allow us to reduce the scope of pipeline replacement facilities. That resulted in 13 Mdt/d of capacity being relinquished and incorporated into the replacement project.

On November 29, 2004, we filed an application with the FERC for certificate authorization to construct and operate the “Capacity Replacement Project.” This project entails the abandonment of approximately 268 miles of the existing 26-inch pipeline, and the construction of approximately 80 miles of new 36-inch pipeline and an additional 10,760 net horsepower of compression at two existing compressor stations. The original cost of the abandoned assets and any cost of removal, net of salvage, will be charged to Accumulated Depreciation. At December 31, 2005, the net book value of the assets to be abandoned was $82.4 million. The estimated total cost of the proposed Capacity Replacement Project included in the filing is approximately $333 million, net of a $3.3 million contribution-in-aid-of-construction from a shipper that agreed to relinquish 13 Mdt/d of capacity. A favorable preliminary determination was issued in May 2005 and we received and accepted the final FERC certificate in September 2005. We began construction of certain critical river crossings in late 2005. The main construction of pipeline and compression will begin in early 2006 with an anticipated in-service date of November 1, 2006.

We anticipate filing a rate case to recover the capitalized costs relating to restoration and replacement facilities to become effective following the in-service date of the replacement facilities.

In 2005, Northwest Pipeline served a total of 143 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 2005 accounted for approximately 17.6 percent and 11.0 percent, of its total operating revenues. No other customer accounted for more than 10 percent of Northwest Pipeline’s total operating revenues in 2005. 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

Colorado gas pipeline expansion

In January 2006, we filed an application with the FERC to construct a 38-mile expansion that would provide additional capacity in northwest Colorado. The planned expansion would increase capacity by 450 Mdt/d through the 30-inch diameter line and is estimated to cost $55 million. We are currently in discussions with shippers to determine the level of commitment and anticipate beginning service on the expansion in January 2007.

Operating statistics

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

	2005	2004	2003
		(In trillion British Thermal Units)	
Total Transportation Volume	673	650	682
Average Daily Transportation Volumes	1.8	1.8	1.9
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	.6	.5

(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. In December 2001, Gulfstream filed an application with the FERC to allow Gulfstream to complete the construction of its approved facilities in phases. In May 2002, the first phase of the project was placed into service at a cost of approximately $1.5 billion. The second phase of the project was placed into service on February 1, 2005. The total capital cost of both phases of the project is approximately $1.7 billion. At December 31, 2005, our investment in Gulfstream was $395 million. Gas Pipeline and Duke Energy, through their respective subsidiaries, each hold a 50 percent ownership interest in Gulfstream and provide operating services for Gulfstream.

Gulfstream expansion projects

Gulfstream has entered into a conditional agreement pursuant to which, subject to the receipt of all necessary regulatory approvals and other conditions precedent therein, we intend to further expand the system and fully subscribe the existing pipeline system on a long-term basis. The estimated capital cost of this expansion project, if implemented, is anticipated to be approximately $135 million. In addition, we are pursuing another potential prospect for an expansion. Such expansion, if successful, would require estimated capital costs of not less than $100 million, and would expand the current mainline capacity of 1.1 million Dth per day to at least 1.25 million Dth per day. Implementation of our two proposed expansion projects may require additional compression at Station 100 in Coden, Alabama, and new compression facilities at Station 200 in Florida. No significant increase in operations personnel is expected as a result of our two proposed expansion projects.

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 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 10 percent interest in the La Concepcion area located in western Venezuela.

Exploration & Production’s primary strategy is to utilize its expertise in the development of tight-sands 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 over 51 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.

Oil and gas properties

Rocky Mountain properties

The Piceance basin is located in northwestern Colorado, where we primarily target tight sands reserves, and is our largest area of concentrated development comprising approximately 64 percent of our proved reserves at December 31, 2005. This area has approximately 1,400 undrilled proved locations in inventory. Within this basin, we are also the owner and operator of a natural gas gathering system. In 2005, we drilled 320 gross wells and produced a net of approximately 116 Bcfe of natural gas from the Piceance basin. Our estimated proved reserves in the Piceance basin at year-end 2005 were 2,155 Bcfe. In March 2005 we entered into a contract with Helmerich & Payne (NYSE: HP) for the operation of 10 new FlexRig® drilling rigs, each for a term of three years.

The San Juan basin is located in northwest New Mexico and southwest Colorado. In 2005, we participated in the drilling of 189 gross wells, of which we operate 52, and produced a net of approximately 55 Bcfe from the San Juan basin. Our estimated proved reserves in the San Juan basin at year-end 2005 were 663 Bcfe.

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 operate approximately 2,780 wells in the basin and have an interest in approximately 2,504 additional wells. We have a significant inventory of undrilled locations, providing long-term drilling opportunities. In 2005, we participated in the drilling of 960 gross wells from this basin, of which we operate 400, and produced a net of approximately 42 Bcfe of natural gas. Our estimated proved reserves in the Powder River basin at year-end 2005 were 346 Bcfe.

Mid-Continent properties

In 2005, we drilled 75 gross wells, of which we operate 49, in the southeastern Oklahoma portion of the Arkoma basin and the Barnett Shale in the Fort Worth basin of Texas. We produced a net of approximately 7 Bcfe of natural gas in 2005 and our estimated proved reserves in the Arkoma and Fort Worth basins at year-end 2005 were 147 Bcfe.

Gas reserves and wells

The following table summarizes our natural gas reserves as of December 31 (using prices at December 31 held constant) for the year indicated:

	2005	2004	2003
		(Bcfe)	
Proved developed natural gas reserves	1,643	1,348	1,165
Proved undeveloped natural gas reserves	1,739	1,638	1,538
Total proved natural gas reserves	3,382	2,986	2,703

The following table summarizes our proved natural gas reserves by basin as of December 31, 2005:

Basin	Percentage of Proved Reserves
Piceance	64%
San Juan	20%
Powder River	10%
Other	6%
	100%

No major discovery or other favorable or adverse event has caused a significant change in estimated gas reserves since year-end 2005. 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, 2005, 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. 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 97 percent of our year-end 2005 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, 2005 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. Reserves estimates related to properties underlying the Williams Coal Seam Gas Royalty Trust which comprise another approximately two percent of our total U.S. proved reserves were prepared by Miller and Lents, LTD.

The following table summarizes our leased acreage as of December 31, 2005:

	Gross Acres	Net Acres
Developed	722,490	370,492
Undeveloped	1,233,507	641,973

At December 31, 2005, we owned interests in 11,339 gross producing wells (5,199 net) on our leasehold lands.

Operating statistics

We focus on lower-risk development drilling. Our drilling success rate was 99 percent in 2005, 2004 and 2003. 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		
2005	1,627	867
2004	1,395	710
2003	900	419
Successful		
2005	1,615	859
2004	1,384	706
2003	891	414

Substantially all our natural gas production is currently being sold to Power at prevailing market prices. Because we currently have a low-risk drilling program in proven basins, the main component of risk that we manage is price risk. Exploration & Production natural gas hedges for 2006 consist of derivative contracts with Power that hedge 299 BBtud in fixed price hedges (whole year) and approximately 115 BBtud in NYMEX and regional collars for January through March for projected 2006 domestic natural gas production. Power then enters into offsetting derivative contracts with unrelated third parties. Our natural gas production hedges in 2005 consisted of 286 BBtud in fixed price hedges, 50 BBtud in NYMEX collars and an additional 50 BBtud in regional collars for the fourth quarter only. Hedging decisions are made considering the overall Williams commodity risk exposure and are not executed independently by Exploration & Production; there are gas purchase hedging contracts executed on behalf of other Williams entities which taken as a net position may counteract Exploration & Production gas sales hedging derivatives.

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

	2005	2004	2003
Total net production sold (in Bcfe)	223.5	189.4	182.1
Average production costs including production taxes per thousand cubic feet of gas equivalent (Mcfe) produced	$ .92	$ .88	$ .76
Average sales price per Mcfe	$ 6.41	$ 4.48	$ 3.87
Realized impact of hedging contracts (Loss)	$ (1.61)	$ (1.32)	$ (.51)

Acquisitions & Divestitures

Exploration & Production acquired an acreage position in the Forth Worth basin in north-central Texas, that includes 26.9 Bcf of proved reserves as of year end 2005. Our entry into this basin allows us to own an operated position that has potential for significant growth. It increases our diversification into the Mid-continent region and allows us to use our horizontal drilling expertise to develop wells in the Barnett Shale formation.

We sold certain non-core assets in the Wyoming Powder River basin that include approximately 9.6 Bcf of proved reserves. These assets are outside of our main area of development in the basin and are operated by third parties.

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 continued to sell trust units on the open market and as of March 1, 2006, we own 789,291 trust units.

International exploration and production interests

We also have investments in international oil and gas interests, principally through our approximately 69 percent interest in Apco Argentina. If combined with our domestic proved reserves, our international interests would make up 6.1 percent of our total proved reserves.

Midstream

Our Midstream segment, one of the nation's largest natural gas gatherers and processors, has primary service areas concentrated in the major producing basins of San Juan, Wyoming, the Gulf of Mexico, Venezuela and western Canada. Our primary businesses — natural gas gathering, treating, and processing; natural gas liquids (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. 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 NGLs extracted and 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 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 an exposure similar to our "Keep Whole" contracts. We are exposed to the spread between the price for natural gas and the 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.

Key variables for our business will continue to be:

- 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.

Domestic gathering and processing

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 80 percent of our Exploration & Production group's wellhead production in this basin. Several of our western gathering systems serve as critical sources of supply for Northwest Pipeline customers.

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 8,100 miles of gathering pipelines, nine processing plants (one partially owned) and six natural gas treating plants with a combined daily inlet capacity in excess of 5.8 billion cubic feet per day. In addition to these natural gas assets, we own and operate three crude oil pipelines totaling approximately 270 miles with a capacity of more than 300,000 barrels per day. This includes our Mountaineer crude oil pipeline in the deepwater Gulf of Mexico that serves the Dominion Exploration & Production-operated Devils Tower field. *See Gathering and processing — deepwater projects below.*

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). We own a partial interest in Discovery and 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.

Effective June 1, 2004, and due in part to our response to FERC Order 2004, management, operations and decision-making control of certain regulated gathering assets in the Midstream segment were transferred to the Gas Pipeline segment. These assets are owned by Transco, but prior to this change were commercially and physically operated by Midstream. We also requested and were granted a partial waiver allowing us to continue to manage and operate the Discovery Gas Transmission and Black Marlin assets. In order to comply with the remaining provisions of the FERC order, we determined it was necessary to transfer the management of our equity investment in the Aux Sable processing plant to Power. This transfer was effective September 21, 2004.

Gulf Coast petrochemical and olefins

We own a 5/12 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. During the fourth quarter of 2004, we closed on the sale of our interest in an associated ethane/ethylene storage and transportation complex located in Choctaw, Louisiana. We continue to own a ethane pipeline system in Louisiana.

Our Gulf Liquids New River LLC (Gulf Liquids) business consisted of two refinery off-gas processing facilities, an olefins fractionator and propylene splitter and connecting pipeline systems in Louisiana. During the third quarter of 2005, we completed the sale of the olefins fractionator and the related pipeline system. We continue to own and operate the propylene splitter and its related pipeline system.

Venezuela

Our Venezuelan investments involve gas compression and gas processing and natural gas liquids fractionation operations. We own controlling interests in three gas compressor facilities which provide roughly 65 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.

Canada

Our Canadian operations include an olefin liquids extraction plant located near Ft. McMurray, Alberta and an olefin fractionation facility near Edmonton, Alberta. These facilities extract olefinic liquids from the off-gas produced from oil sands bitumen upgrading and then fractionate, treat, store and terminal 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 off-gas. These operations extract valuable petrochemical feedstocks from tar sands refinery off-gas streams allowing our customers 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 NGL products.

We sold our three straddle plants in western Canada to Inter Pipeline Fund of Calgary on July 28, 2004. The sale included our 100 percent ownership interest in the Cochrane and Empress II plants, and our 50 percent interest in the Empress V facility.

Other

We own interests in and/or operate NGL fractionation and storage assets. These assets include two partially owned NGL fractionation facilities near McPherson, 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.

Williams Partners L.P.

Williams Partners L.P. (Williams Partners) was formed to engage in the business of gathering, transporting and processing natural gas and fractionating and storing NGLs. We own approximately 60 percent of Williams Partners. Williams Partners provides us with an acquisition currency that is expected to enable growth of our midstream business. Williams Partners also creates a vehicle to monetize our qualifying assets through sales. Such sales, which are subject to approval by both our and Williams Partners' general partner's board of directors, allow us to retain control of the assets through our ownership interest in Williams Partners.

Williams Partners owns a 40 percent equity investment in the Discovery gathering, transportation, processing and NGL fractionation system; the Carbonate Trend sour gas gathering pipeline; three integrated NGL storage facilities near Conway, Kansas; and a 50 percent interest in an NGL fractionator near Conway, Kansas.

Expansion projects

Gathering and processing

In the first quarter of 2004, we began processing additional gas volumes at our Opal processing plant following an expansion completed by Willbros Mt. West, Inc., a business unit of Willbros Group, Inc. The new volumes are being produced by affiliates of Shell Exploration & Production Company in southwestern Wyoming's Pinedale Anticline and other area producers. This expansion involved the construction of a fourth cryogenic processing train at our existing gas plant in Opal, Wyoming. This fourth train boosted Opal's overall processing capacity from 750 MMcf/d to more than 1.1 billion cubic feet per day, with the ability to recover in excess of 50 Mbbls/d of NGL products. Originally, this fourth train was owned by Willbros Mt. West, Inc. and revenues from the processing were shared with Willbros. We purchased this plant from Willbros in January 2006, and now operate only for our interests.

From the Opal plant, gas can be delivered to markets throughout the West Coast and in the Rockies via connections to three interstate pipelines — Colorado Interstate Pipeline, Kern River Pipeline and our own Northwest Pipeline.

Gathering and processing — deepwater projects

The deepwater Gulf continues to be an attractive growth area for our Midstream business. Investments like our Alpine pipeline and Devils Tower production facilities continue to increase our fee-based business and our scale in the Gulf.

Our floating production system and associated pipelines, Devils Tower, became operational on May 5, 2004. Initially built to serve Dominion Exploration & Production's 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 the Triton and Goldfinger fields in addition to the Devils Tower field. Located in 5,610 feet of water, it is the world's deepest dry tree spar. The platform, which is operated by Dominion on our behalf, is capable of producing 60 MMcf/d of natural gas and 128 Mbbls/d of oil.

The Devils Tower project includes gas and oil pipelines. The 102-mile Canyon Chief gas pipeline consists of 18-inch diameter pipe. The 117-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.

Our 18-inch oil pipeline, Alpine, which became operational on December 14, 2003 is averaging approximately 17.6 Mbbls/d for the fourth quarter of 2005. 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 Kerr-McGee Oil & Gas Corporation, a wholly-owned subsidiary of Kerr-McGee Corporation.

Since 1997, we have invested almost $1 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.

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 2005, these operations gathered and processed gas for approximately 200 gas gathering customers and 130 processing customers. Our top three gathering and processing customers accounted for about 34 percent of our domestic gathering revenue and processing gross margin. Our gathering and processing agreements are generally long-term agreements.

In addition to our gathering and processing operations, we also 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 PDVSA. The significant contracts have a remaining term between 12 and 16 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 political situation in Venezuela has enjoyed relative calm since the defeat of the 2004 referendum to remove President Hugo Chavez from office. However, President Chavez has confirmed his public criticism of U.S. policy and has implemented unilateral changes to existing energy related contracts, indicating that a level of political risk still remains.

Financial & operating statistics

The following table summarizes our significant operating statistics for Midstream (see Note 1 of our Notes to Consolidated Financial Statements):

	2005	2004	2003
Volumes(1):			
Domestic Gathering (trillion British Thermal Units)(2)	1,253	1,252	1,272
Domestic Natural Gas Liquid Production (Mbbls/d)(3)	144	155	129
Crude Oil Gathering (Mbbls/d)(3)	88	83	68

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

(2) Prior periods for Domestic Gathering have been restated to reflect the transfer of the jurisdictional assets to Transco.

(3) Annual Average Mbbls/d

Other

At December 31, 2003, we owned approximately 32 percent of Longhorn, which owns a refined petroleum products pipeline from Houston, Texas to El Paso, Texas. During February 2004, we participated in a recapitalization plan completed by Longhorn, following which our subsidiaries, Longhorn Enterprises of Texas, Inc. (LETI) and Williams Petroleum Services, LLC (WPS), together own, directly or indirectly, approximately 94.7 percent of the Class B Interests in Longhorn Pipeline Investors, LLC (Pipeline Investors) and approximately 21.3 percent of the Common Interests therein. Pipeline Investors indirectly owns Longhorn. The recapitalization provided the funds necessary to complete final construction and start-up of the pipeline. As part of the recapitalization, LETI sold a portion of its limited partner interests in Longhorn for $11.4 million, and LETI and WPS sold a portion of the debt owed to them individually by Longhorn for approximately $58 million. In addition, in exchange for the Common Interests described above, LETI contributed the remaining balance of its limited partnership interests, and WPS contributed all of its general partnership interests in the general partner of Longhorn. LETI and WPS also exchanged the remaining debt owed by Longhorn for the Class B Interests described above. The Class B Interests are preferred interests but subordinate to the new investors' preferred interests, and the Common Interests are subordinate to both.

During the first quarter of 2005, Longhorn became fully operational as deliveries commenced through both the Odessa and El Paso terminals. However, the pipeline's throughput fell significantly short of management expectations. The primary driver behind this volume shortfall was the narrowing of the refined product pricing differentials between the Gulf Coast and El Paso markets. During the second quarter of 2005, Longhorn management indicated the shortfall was likely to continue and that the original business model was no longer feasible. A financial advisor was engaged to develop alternative economic options for the pipeline. The three primary alternatives being considered were:

- sale of the pipeline;
- conversion to alternative service;
- expansion to the Phoenix/ Tucson markets.

As a result of the other-than-temporary decline in fair value identified in the second quarter, we impaired the Common Interests by $16.2 million and the Class B shares by $32.7 million. After these adjustments, our book value of our investment in Longhorn (as of June 30, 2005) totaled $51.6 million, comprised of $25.0 million of Common Interests and $26.6 million of Class B shares.

During the third quarter of 2005, we provided $10 million of a $50 million fully collateralized bridge loan to fund operations of Longhorn until an economically feasible operational alternative was developed. In the fourth quarter of 2005, management of Longhorn concluded that its preferred strategy was the sale of the Longhorn assets. Accordingly, they directed the financial advisor to solicit offers from several entities. The financial advisor is currently working to facilitate a transaction by the end of the second quarter 2006. After reviewing the terms and conditions of the bids, our management has determined a full impairment of our investment in the Class B and Common Interests is appropriate. This decision resulted in a December 31, 2005 write-down of the remaining $38.1 million in book value which had been further reduced by additional equity losses during the third and fourth quarters. However, we expect to receive full payment on the $10 million bridge loan from the proceeds of the sale.

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” sold in 2003 and 2004 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, administrative and other services for our subsidiaries.

Our principal sources of cash are from external financings, dividends and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, 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 many 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 Power, we are required by counterparties 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

Power. Our Power business is subject to a variety of laws and regulations at the local, state and federal levels, including regulation by the FERC and the Commodity Futures Trading Commission. In addition, electricity and natural gas markets in California and elsewhere 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.

Gas Pipelines. Gas Pipeline's interstate transmission and storage activities are subject to regulation by the FERC 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 Order 2004 "Standards of Conduct for Transmission Providers" governs how our interstate pipelines communicate and do business with their energy affiliates, Power and Exploration & Production. One of the cornerstones of Order 2004 is that interstate pipelines will not operate their pipeline systems to preferentially benefit their energy 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.

Exploration & Production. Our Exploration & Production business is subject to various federal, state and local laws and regulations on taxation, 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.

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 operates, currently only Kansas and Texas actively regulate gathering activities. Those states regulate 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, 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."

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.

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

ENVIRONMENTAL MATTERS

Our generation 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, because we acquire properties that have been operated in the past by others, we may be liable for environmental damage caused by such former operators.

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, imposing limitations on generation facility availability, 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 (which we believe would be granted).

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

Power. In our Power segment, we compete directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities and natural gas producers. We also compete with both brokerage houses and other energy-based companies offering similar services. Since 2002, we have fewer competitors due to the exit of independent energy marketers from the marketplace and the exit of utilities from financial merchant activities. We anticipate more competition in the future from brokerage houses, which are increasing their trading activity.

Gas Pipeline. Our Gas Pipeline segment faces increased competition as a result of various actions taken by the FERC and several states in which we operate to strengthen market forces in the natural gas pipeline industry. In a number of key markets, interstate pipelines are now facing competitive pressures from other major pipeline systems, enabling local distribution companies and end users to choose a supplier or switch suppliers based on the short-term price of gas and the cost of transportation. We expect competition for natural gas transportation to continue to intensify in future years due to increased customer access to other pipelines, rates, competitiveness among pipelines, customers' desire to have more than one transporter, shorter contract terms, regulatory developments, and development of LNG facilities particularly in our market areas. Future utilization of pipeline capacity will depend on competition from other pipelines and LNG facilities, use of alternative fuels, the general level of natural gas demand, and weather conditions.

Suppliers of natural gas are able to compete for any gas markets capable of being served by pipelines using nondiscriminatory transportation services provided by the pipeline companies. As the regulated environment has matured, many pipeline companies have faced reduced levels of subscribed capacity as contractual terms expire and customers opt to reduce firm capacity under contract in favor of alternative sources of transmission and related services. This situation, known in the industry as "capacity turnback," is forcing the pipeline companies to evaluate the consequences of major demand reductions in traditional long-term contracts. It could also result in significant shifts in system utilization, and possible realignment of cost structure for remaining customers since all interstate natural gas pipeline companies continue to be authorized to charge maximum rates approved by the FERC on a cost of service basis. Gas Pipeline does not anticipate any significant financial impact from "capacity turnback." We anticipate that we will be able to remarket most future capacity subject to future capacity turnback, although competition may cause some of the remarketed capacity to be sold at lower rates or for shorter terms.

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.

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, master limited partnerships (MLP), 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 well connections, pressure obligations and the willingness of the provider to process for either a fee or for liquids taken in-kind. We also compete in recruiting and retaining skilled employees. In 2005 we formed Williams Partners to help compete against other master limited partnerships for midstream projects. By virtue of the master limited partnership structure, Williams Partners provides us with an alternative and low-cost source of capital. We expect the alternative, low-cost capital will allow it to compete with other MLPs when pursuing acquisition opportunities of gathering and processing assets.

EMPLOYEES

At February 28, 2006, we had approximately 3,913 full-time employees including 856 at the corporate level, 116 at Power, 1,574 at Gas Pipeline, 502 at Exploration & Production, and 865 at Midstream. None of our employees are represented by unions or covered by collective bargaining agreements.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Note 18 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 18 of our Notes to Consolidated Financial Statements for information relating to long-lived assets during the last two fiscal years, other than financial instruments, long-term customer relationships of a financial institution, mortgage and other servicing rights and deferred policy acquisition costs, 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, excluding historical information, include forward-looking statements — statements that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report 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;
- seasonality of certain business segments;
- power and gas 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.

Some of these risks are described in the "Risk Factors" section of this report and one should keep in mind these risk factors when considering forward-looking statements. 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 obligation to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments. Further, the information about our intentions contained or incorporated into this report represents our intention as of the date of this report and is based on, among other things, the existing regulatory environment, industry conditions, market conditions and prices, the economy in general and our assumptions as of such date. We may change our intentions, at any time and without notice, based upon any changes in such factors, in our assumptions, or otherwise.

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 transmission 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 additional natural gas reserves 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 of additional reserves and production, gathering, storage and pipeline transmission and import and export of natural gas supplies. Additional natural gas reserves might not be developed in commercial quantities and in sufficient amounts to fill the capacities of our gathering, transmission and processing pipeline facilities. Additionally, in some cases, new LNG import facilities built near our markets could result in less demand for our gathering and transmission facilities.

Estimating reserves and future net revenues involves uncertainties and negative revisions to reserve estimates, and oil and gas price declines may lead to impairment of oil and gas assets.

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 which 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. Lower oil and gas prices 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.

Historic performance of our exploration and production business is no guarantee of future performance.

Our success rate for drilling projects in 2005 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, 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 cost-effective transportation for products;
- market risks 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 costs.

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, 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. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. Certain segments of our pipelines run through such areas. 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 position and results of operations, 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 adversely impact our ability to meet contractual obligations and retain customers.

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, 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 will require significant expenditures, including for clean up costs and damages arising out of contaminated properties. The possible failure to comply with environmental laws and regulations that 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.

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 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, including gas transmission and the sale of electric power, can have seasonal characteristics. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, demand for power peaks during the winter. In addition, demand for 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 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 power sale agreements and gas transmission 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 Power, which uses gas as a fuel source, 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 laws of other countries, 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 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.

Operations in foreign countries also can present currency exchange rate and convertibility, inflation and repatriation risk. In certain conditions under which we develop or acquire projects, or make investments, economic and monetary conditions and other factors could affect our ability to convert 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. Foreign currency risk can also arise when the revenues received by our foreign subsidiaries are not in U.S. dollars. In such cases, a strengthening of the U.S. dollar could reduce the amount of cash and income we receive from these foreign subsidiaries. We have put contracts in place to mitigate our most significant foreign currency exchange risks. We have some exposures that are not hedged which could result in losses or volatility in our earnings.

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 default or 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.

Developments affecting the wholesale power and energy trading industry sector have reduced market activity and liquidity and might continue to adversely affect our results of operations.

In 2004, we announced our decision to maintain our wholesale power and energy trading business and trading portfolio. Therefore, the legacy issues arising out of the 2000-2001 energy crisis in California, the resulting collapse in energy merchant credit and volatility in natural gas prices, the Enron Corporation bankruptcy filing, and investigations by governmental authorities into energy trading activities and increased litigation related to such inquiries, could continue to affect us in the future. These market factors have led to industry-wide downturns that have resulted in some companies being forced to exit the energy trading markets leading to a reduction in the number of trading partners and market liquidity.

Our lack of investment grade credit ratings increases our costs of doing business in many ways and increases our risks from market disruptions and further credit downgrades.

Because we do not have an investment grade credit rating, our transactions in each of our businesses require greater credit assurances, both to be given from, and received by, us to satisfy credit support requirements. In addition, we are more vulnerable to the impact of market disruptions or a further downgrade of our credit rating that might further increase our cost of borrowing or further impair our ability to access one or any of the capital markets. Such disruptions could include:

- further economic downturns;
- deteriorating capital market conditions generally;
- declining market prices for electricity and natural gas;
- 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.

Despite our restructuring efforts, we may not attain investment grade ratings.

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 goal is to attain investment grade ratios. However, there is no guarantee that the credit rating agencies will assign us investment grade ratings even if we meet or exceed their criteria for investment grade ratios.

Electricity, natural gas liquids and gas prices 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, profitability, future rate of growth and the value of our power and gas businesses depend primarily upon the prices we receive for natural gas, electricity and other commodities. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital.

Historically, the markets for these commodities have been volatile and they 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 electricity, natural gas, petroleum, and related commodities;
- turmoil in the Middle East and other producing regions;
- 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;
- 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.

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

Our portfolios consist of wholesale contracts to buy and sell commodities, including contracts for electricity, 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, we could realize material losses from our marketing. 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. In such event, 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 financing transaction fails to perform and any collateral that secures our counterparty's obligation is inadequate, we will lose money.

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 gas sales, transmission, and storage operations are subject to government regulations and rate proceedings that could have an adverse impact on the profitability of these operations.

Our interstate gas sales, transmission, 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.

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 transmission provider based on considerations other than location.

Our revenues might decrease if we are unable to gain adequate, reliable and affordable access to transmission and distribution assets due to the FERC and regional regulation of wholesale market transactions for electricity and gas.

We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity and natural gas we buy and sell in the wholesale market. If transmission 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. The FERC has issued power transmission regulations that require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, we believe that some companies may have failed to provide fair and equal access to their transmission systems or have not provided sufficient transmission capacity to enable other companies to transmit electric power. We cannot predict whether and to what extent the industry will comply with these initiatives, or whether the regulations will fully accomplish the FERC's objectives.

In addition, the independent system operators who oversee the transmission systems in regional power markets, such as California, have in the past been authorized to impose, and might continue to impose, price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms might adversely impact the profitability of our wholesale power marketing and trading. Given the extreme volatility and lack of meaningful long-term price history in many of these markets and the imposition of price limitations by regulators, independent system operators or other marker operators, we can offer no assurance that we will be able to operate profitably in all wholesale power markets.

The different regional power markets in which we compete or will compete in the future have changing regulatory structures, which could affect our growth and performance in these regions.

Our results are likely to be affected by differences in the market and transmission regulatory structures in various regional power markets. Problems or delays that might arise in the formation and operation of new regional transmission organizations (RTOs) might restrict our ability to sell power produced by our generating capacity to certain markets if there is insufficient transmission capacity otherwise available. The rules governing the various regional power markets might also change from time to time which could affect our costs or revenues. Because it remains unclear which companies will be participating in the various regional power markets, or how RTOs will develop and evolve or what regions they will cover, we are unable to assess fully the impact that these power markets might have on our business.

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.

Existing regulations might be revised or reinterpreted, new laws and regulations might be adopted or become applicable to us or our facilities, 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, including California, 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. We cannot assure you that other proposals to re-regulate will not be made or that legislative or other attention to the electric power restructuring process will not cause the deregulation process to be delayed or reversed.

The outcome of pending rate cases to set the rates we can charge customers on certain of our pipelines might result in rates that do not provide an adequate return on the capital we have invested in those pipelines.

We anticipate that in the next twelve months we will file rate cases with the FERC to request changes to the rates we charge on Northwest Pipeline and Transco. The outcome of those rate cases is uncertain. There is a risk that rates set by the FERC will be lower than is necessary to provide us with an adequate return on the capital we have invested in these assets. 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 many 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.

Such 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 disclosure in the future, which might change the way analysts measure our business or financial performance.

Accounting irregularities discovered in the past few years in various industries have forced regulators and legislators to take a renewed look at accounting practices, financial disclosures, companies' relationships with their independent auditors and retirement plan practices. Because it is still unclear what laws or regulations will ultimately develop, 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 and liabilities.

Risks Related to Market Volatility and Risk Management

Our reported results are subject to volatility around our use of derivatives that hedge the economic risk of our commodity exposures. Some derivatives do not qualify as hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," (SFAS 133) and so changes in fair value are recorded to income. During the period from 2002 to 2004 when our Power business was for sale, most changes in the fair value of derivatives used in our Power business were recorded to income as net forward unrealized mark-to-market gains. In future periods, the cash associated with those hedges could be realized but the value will have already been recorded in income.

Our risk measurement and hedging activities might not prevent losses.

We manage our commodity price risk for our unregulated businesses as a whole. Although we have risk measurement systems in place that use various methodologies to quantify risk, these systems might not always be followed or might not always work as planned. Further, such risk measurement systems do not in themselves manage risk, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, and changes in interest rates might still adversely affect our earnings and cash flows and our 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, including our long-term tolling agreements. 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, as well as long-term structured transactions when feasible. 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 tolling 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 could be impacted by counterparty default.

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;
- a change in the difference between published price indexes established by pipelines in which our hedged production is delivered and the reference price established in the hedging arrangements is such that we are required to make payments to our counterparties;
- the counterparties to our hedging arrangements fail to honor their financial commitments.

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

Institutional knowledge residing with current employees or our former employees now employed by our outsourcing service providers 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. Other qualified individuals could leave us or refuse our offers of employment if our recruiting and retention efforts are unsuccessful. Our efforts at knowledge transfer could be inadequate.

Due to the large number of our former employees who were migrated to an outsourcing provider in 2004, access to significant amounts of internal historical knowledge and expertise could become unavailable to us, particularly if knowledge transfer initiatives are delayed or ineffective.

Failure of the 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, 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.

Our ability to receive services from outsourcing provider locations outside of the United States might be impacted by cultural differences, political instability, or unanticipated regulatory requirements in jurisdictions outside the United States.

Certain accounting, information technology application development, human resources, and helpdesk services that are currently provided by our outsourcing provider were relocated to service centers outside of the United States during 2005. 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 affected by weather and other natural phenomena.

Our assets and operations, especially 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.

Our current information technology infrastructure is aging and may adversely affect our ability to conduct our business.

Limited capital spending for information technology infrastructure during 2001-2003 resulted in an aging server environment that may not be adequate for our current business needs. While efforts are ongoing to update the environment, the current age and condition of equipment could result in loss of internal and external communications, loss of data, inability to access data when needed, excessive software downtime (including downtime for critical software applications), and other disruptions that could have a material adverse impact on our business.

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

None.

Item 2. ***Properties***

We own property in 34 states plus the District of Columbia in the United States and in Argentina, Canada and Venezuela.

Power's primary assets are its term contracts, related systems and technological support. In addition, affiliates of Power own the Hazelton and Milagro generating facilities described above. 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 Contingent liabilities and commitments included in 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 28, 2006, are listed below.

Alan S. Armstrong	Senior Vice President, Midstream Age: 43 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.
James J. Bender	Senior Vice President and General Counsel Age 49 Position held since December 16, 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: 54 Position held since April 16, 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.
Ralph A. Hill	Senior Vice President, Exploration & Production Age: 46 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.
William E. Hobbs	Senior Vice President, Power Age: 46 Position held since October 2002 From February 2000 to October 2002, Mr. Hobbs was President and Chief Executive Officer of Williams Energy Marketing & Trading. From 1997 to February 2000, he served as a Vice President of various Williams subsidiaries.
Michael P. Johnson, Sr.	Senior Vice President and Chief Administrative Officer Age: 58 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.
Steven J. Malcolm	Chairman of the Board, Chief Executive Officer and President Age: 57 Position held since September 21, 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.
Phillip D. Wright	Senior Vice President, Gas Pipeline Age: 50 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.

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 and Pacific Stock Exchanges under the symbol "WMB." At the close of business on February 28, 2006, we had approximately 12,510 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:

	2005			2004		
Quarter	High	Low	Dividend	High	Low	Dividend
1st	$ 19.29	$ 15.29	$ .05	$ 11.30	$ 8.75	$ .01
2nd	$ 19.21	$ 16.29	$ .05	$ 12.23	$ 9.89	$ .01
3rd	$ 25.05	$ 19.16	$ .075	$ 12.51	$ 11.45	$ .01
4th	$ 25.40	$ 19.97	$ .075	$ 17.10	$ 12.35	$ .05

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. However, until January 20, 2005, the credit agreements underlying our two unsecured revolving credit facilities totaling $500 million prohibited us from paying quarterly cash dividends on our common stock in excess of $0.05 per share. On January 20, 2005, these facilities were terminated and replaced with two new facilities. As part of the transaction, the dividend restriction, along with most of the other restrictive covenants, was removed from the new credit agreements.

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

The following financial data as of December 31, 2005 and 2004, and for the three years ended December 31, 2005, are an integral part of, and should be read in conjunction with, the consolidated financial statements and related notes. All other amounts have been prepared from our financial records. Certain amounts below have been restated or reclassified. See Note 1 of Notes to Consolidated Financial Statements in Item 8 for discussion of changes in 2005, 2004 and 2003. Information concerning significant trends in the financial condition and results of operations is contained in *Management's Discussion & Analysis of Financial Condition and Results of Operations* of this report.

	2005	2004	2003	2002	2001
			(Millions, except per-share amounts)		
Revenues(1)	$ 12,583.6	$ 12,461.3	$ 16,651.0	$ 3,434.5	$ 4,899.5
Income (loss) from continuing operations(2)	317.4	93.2	(57.5)	(618.4)	640.5
Income (loss) from discontinued operations(3)	(2.1)	70.5	326.6	(136.3)	(1,118.2)
Cumulative effect of change in accounting principles(4)	(1.7)	—	(761.3)	—	—
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	.53	.18	(.17)	(1.37)	1.28
Income (loss) from discontinued operations	—	.13	.63	(.26)	(2.23)
Cumulative effect of change in accounting principles	—	—	(1.47)	—	—
Total assets at December 31	29,442.6	23,993.0	27,021.8	34,988.5	38,614.2
Short-term notes payable and long-term debt due within one year	122.6	250.1	938.5	2,077.1	2,510.4
Long-term debt at December 31	7,590.5	7,711.9	11,039.8	11,075.7	8,285.0
Preferred interests in consolidated subsidiaries at December 31	—	—	—	—	976.4
Stockholders' equity at December 31	5,427.5	4,955.9	4,102.1	5,049.0	6,044.0
Cash dividends per common share	.25	.08	.04	.42	.68

(1) As part of our adoption of Emerging Issues Task Force Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," (EITF 02-3), we concluded that revenues and costs of sales from non-derivative contracts and certain physically settled derivative contracts should generally be reported on a gross basis. Prior to the adoption on January 1, 2003, these revenues were presented net of costs. As permitted by EITF 02-3, prior year amounts have not been restated. Also, see Note 1 of Notes to Consolidated Financial Statements for discussion of revenue recognized in 2003 related to the correction of prior period items.

(2) See Note 4 of Notes to Consolidated Financial Statements for discussion of asset sales, impairments and other accruals in 2005, 2004, and 2003.

(3) See Note 2 of Notes to Consolidated Financial Statements for the analysis of the 2005, 2004, and 2003 income (loss) from discontinued operations. Results for the year 2002 also include amounts related to the discontinued operations of Central natural gas pipeline, Mid-America pipeline, Seminole pipeline and Kern River pipeline. Results for the year 2001 also includes amounts related to the discontinued operations of Williams Communications Group, our previously owned subsidiary (WilTel).

(4) The 2005 *cumulative effect of change in accounting principles* is due to implementation of Interpretation (FIN) 47, "Accounting for Conditional Asset Retirement Obligations — an Interpretation of FASB

Statement No. 147." The 2003 cumulative effect of change in accounting principles includes a $762.5 million charge related to the adoption of EITF 02-3, slightly offset by $1.2 million related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations." The $762.5 million charge primarily consists of the fair value of power tolling, load serving, gas transportation and gas storage contracts. These contracts are not derivatives and, therefore, are 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. We also manage a wholesale power business. Our operations are located principally in the United States and are organized into the following reporting segments: Power, Gas Pipeline, Exploration & Production, and Midstream Gas & Liquids (see Note 1 of Notes to Consolidated Financial Statements for further discussion of reporting segments).

Unless indicated otherwise, the following discussion of critical accounting policies and 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 2005

We entered 2005 having completed the key components of our 2003 restructuring plan and in a position to shift our focus to growth. Our 2005 plan included the following objectives:

- Increase focus and disciplined EVA®-based investment in natural gas businesses (EVA® (Economic Value Added) is a registered Trademark of Stern Stewart & Co.);
- Continue to steadily improve credit ratios and ratings with the goal of achieving investment grade ratios;
- Continue to reduce risk and liquidity requirements while maximizing cash flow in the Power segment;
- Maintain liquidity from cash and revolving credit facilities of at least $1 billion;
- Generate sustainable growth in EVA® and shareholder value.

Our 2005 *income from continuing operations* increased to $317.4 million, as compared to $93.2 million in 2004. Our 2005 results reflect the benefit of increased natural gas production and higher net realized average prices, along with reduced levels of interest expense. Results for 2004 included $282.1 million in costs associated with the early retirement of debt, while results for 2005 were reduced by accruals associated with agreements to resolve gas reporting issues and impairments of certain investments. Our *net cash provided by operating activities* was $1.45 billion in 2005, comparable with the 2004 level of $1.49 billion. In addition to achieving these results, the following represent significant actions or events that occurred during the year:

- In 2005, we further improved our credit ratios from those achieved in 2004. We retired $200 million of debt that matured January 15, 2005. On February 16, the holders of the remaining 10.9 million equity forward contracts associated with the FELINE PACS units exercised contracts to purchase one share of our common stock for $25 a share, resulting in cash proceeds of approximately $273 million. The remaining notes associated with the FELINE PACS units totaling approximately $73 million are due February 16, 2007.
- During 2005, Exploration & Production increased its average daily domestic production levels, its net realized average prices, and its developmental drilling activities. In March 2005, Exploration & Production entered into a lease for ten new drilling rigs to support the accelerated pace of natural gas

development in the Piceance basin. The first rig was delivered in January 2006 and the remaining rigs are expected to be delivered during 2006.

- In 2005 and early 2006, Power continued to reduce risk by entering into electricity and capacity forward contracts with fixed sales prices for over 6,000 megawatts of capacity in total across various periods through 2010.
- During 2005, Midstream Gas & Liquids (Midstream) continued efforts to expand operations of large scale assets in growth basins. These efforts include signing definitive agreements to extend oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect and obtaining Board approval to add a fifth cryogenic train to our gas processing plant in Opal, Wyoming. Both of these additions are expected to be in service in 2007.
- In July and November of 2005, our Board of Directors approved regular quarterly dividends of 7.5 cents per share of common stock, which reflects an increase of 50 percent compared with the 5 cents per share paid in each of the three prior quarters.
- On August 23, 2005, Williams Partners L.P. completed its initial public offering of five million common units at a price of $21.50 per unit. The underwriters also fully exercised their option to purchase an additional 750,000 common units at the same price. Upon completion of the transaction, we held approximately 60 percent of the interests in Williams Partners L.P., including 100 percent of the general partner. See the Midstream Gas & Liquids Overview of 2005 within Item 7 for further information.
- During third-quarter 2005, certain Gulf Coast area operations were interrupted by hurricanes. The impact of these hurricanes included temporary shutdowns as well as varying levels of damage. The overall impact was not material to our financial position.
- In September 2005, we reached an agreement to settle litigation filed in 2002 under the Employee Retirement Income Security Act (ERISA). The settlement, which received final approval in November 2005, provided for us to pay $55 million to plaintiffs, of which $50 million was covered and paid by insurance. See Note 15 of Notes to Consolidated Financial Statements for further information.
- In September 2005, we increased our available liquidity by obtaining a total of $700 million of capacity in two five-year unsecured credit facilities. See Note 11 of Notes to Consolidated Financial Statements for further information.
- In November 2005, we initiated an offer to induce conversion of up to $300 million of the 5.5 percent junior subordinated debentures convertible into our common stock. The conversion was executed in January 2006 and approximately $220.2 million of the debentures were exchanged for common stock. See Note 12 of Notes to Consolidated Financial Statements for further information.
- During 2005 we continued our efforts to resolve legacy issues, such as pending claims and investigations involving inaccurate reporting of natural gas prices and volumes to an industry publication in 2002. In February 2006, we reached agreements with various parties to substantially resolve this exposure. Under the terms of these agreements, Power will pay a total of $77.2 million to the various parties. See Note 15 of Notes to Consolidated Financial Statements for further information.

Outlook for 2006

Our plan for 2006 is focused on continued disciplined growth. Objectives of this plan include:

- Continue to improve both EVA® and segment profit.
- Invest in our natural gas businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position.

- Continue to increase natural gas production.
- Increase the scale of our gathering and processing business in key growth basins.
- File new rates to enable our Gas Pipeline segment to remain competitive and value-creating, while managing our costs and capturing demand growth. These rates are expected to be effective in 2007.
- Execute power contracts that offset a significant percentage of our financial obligations associated with our tolling agreements.

As a result of the strategy to grow our natural gas businesses, we estimate capital expenditures will increase to approximately $2.0 to $2.2 billion in 2006, compared to $1.3 billion in 2005. We expect to fund capital and investment expenditures, debt payments, dividends and working-capital requirements through cash generated from operations, which is currently estimated to be between $1.6 billion and $1.9 billion in 2006, as well as proceeds from debt issuances, sales of units of Williams Partners L.P., and cash and cash equivalents on hand as needed.

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;
- 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 revolving credit facilities.

New Accounting Standards and Emerging Issues

Accounting standards that have been issued and are not yet effective, or that have not yet been issued, may have a material effect on our consolidated financial statements in the future. These include:

- Revised SFAS No. 123, “Share-Based Payment”;
- Proposed SFAS on “Fair Value Measurements” (exposure draft);
- Proposed Interpretation on “Accounting for Uncertain Tax Positions — an interpretation of FASB Statement No. 109 (exposure draft);
- Accounting for Pensions and Other Postretirement Benefits (preliminary views).

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 Policies and Estimates

Our financial statements reflect the selection and application of accounting policies that require management to make significant estimates that require subjective and complex judgment. The selection of these policies has been discussed with our Audit Committee. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Revenue Recognition — Derivatives

We hold a substantial portfolio of energy trading and non-trading contracts for a variety of purposes. We review these contracts to determine whether they are non-derivatives 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 derivatives are expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk. For derivatives that are designated as cash flow hedges, changes in their fair value are not reflected 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, the net change in their fair value is recognized in income currently (marked to market). Derivatives for which the normal purchases and normal sales exception has been elected are accounted for on an accrual basis. The fair value for 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:

- Exchange-traded or over-the-counter markets with quoted prices;
- Exchange-traded 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, *Item 7A — Qualitative and Quantitative Disclosures About Market Risk*, 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 and certain estimated reserves are used as collateral to secure financing. 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. 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 $20 million and $25 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 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, 2005, we have $940 million of deferred tax assets for which a $37 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. Based on our projections, we believe that it is probable that we can utilize our year-end 2005 federal tax net operating loss carryovers and capital loss carryovers prior to their expiration. We are not expecting to be able to utilize $24 million, or approximately $8 million of tax benefit, of the charitable contribution carryovers expiring in 2006. The remaining $20 million of charitable contributions are expected to be utilized prior to their expiration. We also do not expect to be able to utilize $29 million of foreign deferred tax assets related to carryovers. See Note 5 of Notes to Consolidated Financial Statements for additional information regarding the tax 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. In evaluating the liability associated with our various filing positions, we record a liability for probable tax contingencies. The ultimate disposition of these contingencies could have a material 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.

Impairment of Long-Lived Assets And Investments

We evaluate our long-lived assets and investments for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of certain long-lived assets or the decline in carrying value of an investment is other-than-temporary. In addition to those long-lived assets and investments for which impairment charges were recorded (see Notes 2, 3, and 4 of Notes to Consolidated Financial Statements), certain others were reviewed for which no impairment was required. Our computations utilized judgments and assumptions in the following areas:

• The probability that we would sell an asset or continue to hold and use it;

• For assets held for use, estimated fair value of the asset, undiscounted future cash flows, and discounted future cash flows;

• For assets held for sale, estimated sales proceeds, form and timing of the asset disposition, and counterparty performance considerations;

• For investments that may be impaired, whether the potential impairment is other than temporary;

• Current and future economic environment in which the asset operates.

Canadian Olefins

We continue to assess our Canadian olefins assets for impairment based on previously identified indicators. Our investment in these assets is currently not estimated to be recoverable without modifications to or a renegotiation of key terms in an off-gas processing agreement. We have performed recoverability tests that considered varying outcomes relating to successful renegotiation of the processing agreements. Our computations used judgments and assumptions in the following areas:

• Varying terms of renegotiated contracts;

• Commodity pricing;

• Probability weighting of different scenarios;

• Trends in foreign exchange rates.

After applying probability weightings to the various scenarios, we determined that the assets did not require impairment at December 31, 2005 and 2004. A critical assumption in our impairment analysis was the valuation of future contract terms in the related processing agreement. Unsuccessful renegotiation of the contract or a decrease of approximately 20 percent or more in our low case contract valuation estimate would likely result in an impairment.

Aux Sable

We own a 14.6 percent equity interest in Aux Sable Liquid Products LP (Aux Sable), which owns and operates a natural gas liquids extraction and fractionation facility. During 2003, we performed an impairment review of our investment in Aux Sable as operating results and cash flow projections suggested that a decline in the fair value of this investment below our carrying value could exist. We estimated the fair value of our investment based on a projection of discounted cash flows of Aux Sable. Based upon our analysis, we recorded a $14.1 million impairment of this investment.

During 2005, we decided to pursue a potential sale of this investment. We have recorded an impairment of $23 million based on our estimate of sales proceeds from this investment.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Pension and other postretirement benefit plan expense and obligations are calculated by a third-party actuary and 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 table below presents the estimated increase (decrease) in pension and other postretirement 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	$ (14)	$ 15	$ (131)	$ 155
Expected long-term rate of return on plan assets	(9)	9	—	—
Rate of compensation increase	2	(2)	12	(12)
Other postretirement benefits:				
Discount rate	(4)	6	(65)	79
Expected long-term rate of return on plan assets	(2)	2	—	—
Assumed health care cost trend rate	9	(6)	73	(58)

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 the capital market projections provided by our independent investment consultant 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 has been 8.5 percent since 2002. Over the past ten years, our actual average return on plan assets for our pension plans has been approximately 8.6 percent.

The discount rates are used to discount future benefit obligations to today's dollars. Decreases in these rates increase the obligation and 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 corporate bonds.

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.

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, 2005. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,				
	2005	% Change from 2004(1)	2004	% Change from 2003(1)	2003
	(Millions)		(Millions)		(Millions)
Revenues	$ 12,583.6	+1%	$ 12,461.3	-25%	$ 16,651.0
Costs and expenses:					
Costs and operating expenses	10,871.0	-1%	10,751.7	+28%	15,004.3
Selling, general and administrative expenses	325.4	+8%	355.5	+16%	421.3
Other (income) expense — net	61.2	NM	(51.6)	+142%	(21.3)
General corporate expenses	154.9	-29%	119.8	-38%	87.0
Total costs and expenses	11,412.5		11,175.4		15,491.3
Operating income	1,171.1		1,285.9		1,159.7
Interest accrued — net	(664.5)	+20%	(827.7)	+34%	(1,248.0)
Investing income	23.7	-51%	48.0	-34%	73.2
Early debt retirement costs	(.4)	+100%	(282.1)	NM	(66.8)
Minority interest in income of consolidated subsidiaries	(25.7)	-20%	(21.4)	-10%	(19.4)
Other income — net	27.1	+24%	21.8	-43%	38.5
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	531.3		224.5		(62.8)
Provision (benefit) for income taxes	213.9	-63%	131.3	NM	(5.3)
Income (loss) from continuing operations	317.4		93.2		(57.5)
Income (loss) from discontinued operations	(2.1)	NM	70.5	-78%	326.6
Income before cumulative effect of change in accounting principles	315.3		163.7		269.1
Cumulative effect of change in accounting principles	(1.7)	NM	—	+100%	(761.3)
Net income (loss)	313.6		163.7		(492.2)
Preferred stock dividends	—	NM	—	+100%	29.5
Income (loss) applicable to common stock	$ 313.6		$ 163.7		$ (521.7)

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

2005 vs. 2004

The $122.3 million increase in revenues is due primarily to increased revenues at Exploration & Production due to higher natural gas prices and production volumes sold and gas management income, and at Midstream due primarily to increased natural gas liquids (NGL) prices and crude marketing revenue.

Partially offsetting these increases is decreased revenue at Power due primarily to the absence of crude and refined products activity and reduced net forward unrealized mark-to-market gains.

The $119.3 million increase in *costs and operating expenses* is due primarily to increased crude marketing costs and increased NGL costs at Midstream in addition to increased depreciation, depletion and amortization and gas management expense at Exploration & Production. Partially offsetting these increases are decreased costs at Power primarily due to the absence of crude and refined products activity.

The $30.1 million decrease in *selling, general and administrative (SG&A) expenses* is primarily due to a $17.1 million reduction in expenses at Gas Pipeline to record the cumulative impact of a correction to pension expense attributable to the periods 2003 and 2004 and a $9.7 reduction of bad debt expense at Power resulting from the sale of certain receivables to a third party. Partially offsetting these items is increased staffing costs at Exploration & Production in support of increased operational drilling activity.

Other (income) expense — net, within *operating income*, in 2005 includes the following significant items:

- An $82.2 million accrual for litigation contingencies at Power, associated primarily with agreements reached to substantially resolve exposure related to certain natural gas price and volume reporting issues;
- Gains totaling $29.6 million on the sale of two natural gas properties at Exploration & Production;
- A gain of $9 million on a sale of property in the Other segment.

Other (income) expense — net, within *operating income*, in 2004 includes:

- Income of $93.6 million from an insurance arbitration award associated with our Gulf Liquids New River Project LLC (Gulf Liquids) at Midstream;
- Gains of $16.2 million from the sale of Exploration & Production's securities, invested in a coal seam royalty trust, that were purchased for resale;
- A $9.5 million gain on the sale of Louisiana olefins assets at Midstream;
- A $15.4 million loss provision related to an ownership dispute on prior period production included at Exploration & Production;
- An $11.8 million environmental expense accrual related to the Augusta refinery facility in the Other segment;
- A $9 million write-off of previously capitalized costs on an idled segment of Northwest Pipeline's system included in the Gas Pipeline segment.

The $35.1 million increase in *general corporate expenses* is due primarily to $13.8 million of expense related to the settlement of certain insurance coverage issues and a $16 million increase in outside legal costs associated primarily with securities class action matters.

The $163.2 million decrease in *interest accrued — net* is due primarily to lower average borrowing levels in 2005 as compared to 2004.

The $24.3 million decrease in *investing income* is due primarily to a $76.4 increase in impairment charges on our investment in Longhorn Partners Pipeline, L.P. (Longhorn), a $13.9 million increase in Longhorn equity losses, and a $23 million impairment of our Aux Sable equity investment. Partially offsetting these decreases are the following increases:

- A $30.4 million increase in domestic and international equity earnings, excluding Longhorn and Aux Sable;
- The absence in 2005 of a $20.8 million impairment of an international cost-based investment;

- The absence in 2005 of a $16.9 million impairment of our Discovery Producer Services LLC (Discovery) equity investment;

- An $8.6 million gain on the sale of our remaining interests in the MAPL and Seminole assets;

- The absence in 2005 of a $6.5 million Longhorn recapitalization fee.

Early debt retirement costs include premiums, fees and expenses related to the retirement of debt.

Provision (benefit) for income taxes changed unfavorably by $82.6 million due primarily to increased pre-tax income in 2005 as compared to 2004. The effective income tax rate for 2005 is higher than the federal statutory rate due primarily to state income taxes, nondeductible expenses, the effect of taxes on foreign operations and the inability to utilize charitable contribution carryovers. The 2005 effective income tax rate has been reduced by a benefit adjustment to reduce the overall deferred income tax liabilities and favorable settlements on federal and state income tax matters. The effective income tax rate for 2004 is higher than the federal statutory rate due primarily to state income taxes, a charge associated with charitable contribution carryovers and the effect of taxes on foreign operations. A 2004 accrual for income tax contingencies was offset by favorable settlements of certain federal and state income tax matters.

Income (loss) from discontinued operations in 2004 is comprised of gains on the sales of the Canadian straddle plants and the Alaska refinery of $189.8 million and $3.6 million, respectively, as well as $22 million in income from our Canadian straddles discontinued operation. Partially offsetting these are $153 million of charges to increase our accrued liability associated with certain Quality Bank litigation matters.

Cumulative effect of change in accounting principles in 2005 is due to the implementation of FIN 47, (see Note 9 of Notes to Consolidated Financial Statements).

2004 vs. 2003

The $4.2 billion decrease in *revenues* is due primarily to an approximately $3.9 billion decrease in revenues at Power resulting from lower realized revenues from power and crude and refined products. Partially offsetting the decrease was an increase in Midstream's revenues of $97.8 million reflecting higher volumes and improved NGL margins.

The $4.3 billion decrease in *costs and operating expenses* is due primarily to lower costs and operating expenses at Power. This decrease is due primarily to lower purchase volumes of power and crude and refined products.

The $65.8 million decrease in *SG&A expense* is due primarily to a $36 million decrease in compensation expense at Power due to reduced staffing levels, combined with the absence of $13.6 million of expense related to the accelerated recognition of deferred compensation during 2003. In addition, Midstream's *SG&A expense* declined $18 million largely due to asset sales and lower legal expense.

Other (income) expense — net, within *operating income* in 2004 is included in the *2005 vs. 2004* discussion. *Other (income) expense — net,* within *operating income,* in 2003 includes:

- A $188 million gain from the sale of a Power contract;

- Net gains of $96.7 million in from the sale of Exploration & Production's interests in certain natural gas properties in the San Juan basin;

- A $16.2 million gain from Midstream's sale of the wholesale propane business;

- A $12.2 million gain on foreign currency exchange at Power;

- A $9.2 million gain on sale of blending assets at the Other segment;

- Income of $7.2 million at Transcontinental Gas Pipe Line Corporation (Transco) due to a partial reduction of accrued liabilities for claims associated with certain producers as a result of settlements and court rulings included in the Gas Pipeline segment;

- A $108.7 million impairment on Gulf Liquids at Midstream;
- A $45 million goodwill impairment at Power;
- A $44.1 million impairment of the Hazelton generation plant at Power;
- A $25.6 million charge at Northwest Pipeline to write off capitalized software development costs for a service delivery system, included in the Gas Pipeline segment;
- A $20 million charge related to a settlement by Power with the Commodity Futures Trading Commission (CFTC);
- A $19.5 million expense accrual at Power related to an adjustment of California rate refund and other related accruals;
- A $7.2 million impairment of the Aspen project at the Other segment.

The $32.8 million increase in *general corporate expenses* is due primarily to efforts to evaluate and implement certain cost reduction strategies, and initial costs associated with outsourcing of certain services, increased legal costs due primarily to shareholder litigation and ERISA matters, and increased third-party costs associated with certain mandated compliance activities.

The $420.3 million decrease in *interest accrued — net* includes:

- A reduction in interest expense and fees of $206 million at Exploration & Production, due primarily to the May 2003 prepayment of a secured note payable of Williams Production RMT Company (the RMT note);
- A $164 million decrease reflecting lower average borrowing levels;
- A reduction in amortization expense of $46 million related to deferred debt issuance costs, primarily due to the reduction of debt;
- A $24 million decrease reflecting lower average interest rates on long-term debt;
- The absence in 2004 of $14 million of interest expense at Power related to a Federal Energy Regulatory Commission (FERC) ruling in 2003;
- The absence in 2004 of $10 million of interest expense related to a petroleum pricing dispute in 2003;
- A $35 million decrease in capitalized interest due primarily to completion of certain Midstream projects in the Gulf Coast region.

The $25.2 million decrease in *investing income* includes $57.1 million lower interest income due primarily to higher net interest income at Power in 2003 as a result of certain FERC proceedings. The decrease was partially offset by $29.6 million higher equity earnings. Impairments and results from investment sales were substantially comparable in both periods.

Early debt retirement costs include payments in excess of the carrying value of the debt, dealer fees and the write-off of deferred debt issuance costs and discount/premium on the debt.

Provision (benefit) for income taxes increased by $136.6 million due primarily to pre-tax income in 2004 compared to a pre-tax loss in 2003. The effective income tax rate for 2004 is greater than the federal statutory rate due primarily to the effect of state income taxes, a charge associated with charitable contribution carryovers and the effect of taxes on foreign operations. A 2004 accrual for tax contingencies was offset by favorable settlements of certain federal and state income tax matters. The effective income tax rate for the 2003 benefit for income taxes is lower than the federal statutory rate due primarily to nondeductible impairment of goodwill, nondeductible expenses, an accrual for tax contingencies and the effect of state income taxes, somewhat offset by the tax benefit of capital losses.

The primary components of *income (loss) from discontinued operations* in 2004 are included in the *2005 vs. 2004* discussion. *Income (loss) from discontinued operations* in 2003 is composed of the following pre-tax items:

- Gains of $463.4 million on asset sales;
- Income (net of losses) from operations of $197.5 million;
- Asset impairments of $176.1 million;
- Losses of $9.6 million on asset sales.

The *cumulative effect of change in accounting principles* reduced *net income (loss)* for 2003 by $761.3 million due to a $762.5 million charge related to the adoption of EITF 02-3 (see Note 1 of Notes to Consolidated Financial Statements), slightly offset by $1.2 million related to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (see Note 9 of Notes to Consolidated Financial Statements).

In June 2003, we redeemed all of our outstanding 9.875 percent cumulative-convertible preferred shares. Thus, no preferred dividends were paid in 2004.

Results of Operations — Segments

We are currently organized into the following segments: Power, Gas Pipeline, Exploration & Production, Midstream and Other. Other primarily consists of corporate operations and certain continuing operations formerly included in the previously reported International and Petroleum Services segments. Our management currently evaluates performance based on segment profit (loss) from operations (see Note 18 of Notes to Consolidated Financial Statements).

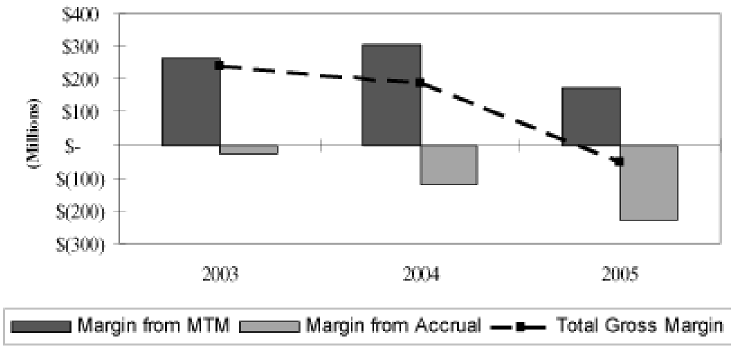
Prior period amounts have been restated to reflect all segment changes. The following discussions relate to the results of operations of our segments.

Power

Overview of 2005

Power's comparative operating results in 2005 were significantly influenced by the effect of cash flow hedge accounting and increased average natural gas and power prices. In fourth quarter 2004, Power designated a portion of its power and natural gas derivative contracts as cash flow hedges. As such, we deferred recognition of certain unrealized mark-to-market gains in *accumulated other comprehensive loss* in 2005. Similar unrealized gains were recorded to earnings in 2004 and 2003 prior to the application of hedge accounting. Power's 2005 earnings do reflect unrealized mark-to-market gains from (1) net increases in the fair value of forward derivative contracts held for trading purposes or which did not qualify for hedge accounting, and (2) hedge ineffectiveness.

Power's 2005 results also reflect the combined impact of increased natural gas and power prices on its nonderivative tolling contracts. Although the average price of power increased, there was a greater increase in the average purchase price of natural gas, which is used to produce power. Hurricane Katrina and mild weather in California affected the prices of natural gas and power. The narrowing of the margin between power and natural gas prices and an outage at an electric generation facility resulted in an accrual gross margin loss (realized costs in excess of realized revenue) on certain tolling contracts. The chart below illustrates the impact of the unrealized mark-to-market gain and accrual gross margin loss on Power's total gross margin (revenue less cost of sales). The below chart does not reflect, however, cash flows that Power realized in 2005 from hedges for which mark-to-market gains or losses had been previously recognized. In 2005, Power had positive cash flows from operations. In addition to these declining margins, significant accruals for litigation contingencies, which were substantially resolved in 2006, and an impairment of an equity investment further adversely impacted Power's 2005 results.



In 2005, Power continued to focus on its objectives of minimizing financial risk, maximizing cash flow, meeting contractual commitments, executing new contracts to hedge its portfolio and providing functions that support our natural gas businesses.

Key factors that may influence Power's financial condition and operating performance include:

- Prices of power and natural gas, including changes in the margin between power and natural gas prices;
- Changes in power and natural gas price volatility;
- Changes in power and natural gas supply and demand;
- Changes in the regulatory environment;
- The inability of counterparties to perform under contractual obligations due to their own credit constraints;
- Changes in interest rates;
- Changes in market liquidity, including changes in the ability to effectively hedge the portfolio.

Outlook for 2006

For 2006, Power intends to service its customers' needs while increasing the certainty of cash flows from its long-term tolling contracts by executing new long-term electricity and capacity sales contracts. In 2005 and early 2006, Power entered into electricity and capacity forward contracts with fixed sales prices for over 6,000 megawatts of capacity in total across various periods through 2010. Most of these contracts are treated on an accrual basis as either operating subleases or normal sales contracts under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133).

As Power continues to apply hedge accounting in 2006, its future earnings may be less volatile. However, not all of Power's derivative contracts qualify for hedge accounting. Because the derivative contracts qualifying for hedge accounting were previously marked to market through earnings prior to their being designated as cash flow hedges, the amounts recognized in future earnings under hedge accounting will not necessarily align with the expected cash flows to be realized from the settlement of those derivatives. For example, to the extent that future earnings reflect losses from underlying transactions, such as natural gas purchases and power sales associated with tolling transactions, that have been hedged by the derivatives, the corresponding offsetting gains from the hedges have already been recognized in prior periods under mark-to-market accounting. However, cash flows from Power's portfolio continue to reflect the net amount from both the hedged transactions and the hedges.

Even with the adoption of hedge accounting, Power's earnings will continue to reflect mark-to-market volatility from unrealized gains and losses resulting from:

- Market movements of commodity-based derivatives that are held for trading purposes;
- Market movements of commodity-based derivatives that represent economic hedges but which do not qualify for hedge accounting;
- Ineffectiveness of cash flow hedges, primarily caused by locational differences between the hedging derivative and the hedged item or changes in the creditworthiness of counterparties.

The fair value of Power's tolling, full requirements, transportation, storage and transmission contracts is not reflected in the balance sheet since these contracts are not derivatives. Some of these contracts have a significant negative estimated fair value and could also result in future operating profits or losses as a result of the volatile nature of energy commodity markets. The inability of counterparties to perform under contractual obligations due to their own credit constraints could also affect future results.

Year-Over-Year Results

	Years Ended December 31, 2005	2004	2003
		(Millions)	
Realized revenues	$ 8,921.8	$ 8,954.7	$ 12,930.5
Net forward unrealized mark-to-market gains	172.1	304.0	262.1
Segment revenues	9,093.9	9,258.7	13,192.6
Cost of sales	9,150.3	9,073.3	12,954.6
Gross margin	(56.4)	185.4	238.0
Operating expenses	22.2	23.7	35.3
Selling, general and administrative expenses	64.5	83.2	124.0
Other (income) expense — net	113.6	1.8	(56.4)
Segment profit (loss)	$ (256.7)	$ 76.7	$ 135.1

2005 vs. 2004

The $164.8 million decrease in revenues includes a $32.9 million decrease in *realized revenues* and a $131.9 million decrease in *net forward unrealized mark-to-market gains*.

Realized revenues represent (1) revenue from the sale of commodities or completion of energy-related services, and (2) gains and losses from the net financial settlement of derivative contracts. The $32.9 million decrease in *realized revenues* is primarily due to the absence in 2005 of $471 million in crude and refined products realized revenues, partially offset by a $444 million increase in power and natural gas realized revenues.

The absence of crude and refined products revenues is due to the sale of the refined products business in 2004. Power and natural gas realized revenues increased primarily due to a 33 percent increase in average natural gas sales prices and a 17 percent increase in average power sales prices. Hurricane Katrina, among other factors, contributed to the increase in prices. A 29 percent decrease in power sales volumes partially offsets the increase in prices. Power sales volumes decreased because Power did not replace certain long-term physical contracts that expired or were terminated and because of mild weather in California, which resulted in lower demand.

Net forward unrealized mark-to-market gains and losses represent changes in the fair values of certain derivative contracts with a future settlement or delivery date that have not been designated as cash flow hedges and the impact of the ineffectiveness of cash flow hedges. The $131.9 million decrease in *net forward unrealized mark-to-market gains* is primarily due to a $165 million decrease associated with power and gas derivative contracts, partially offset by the absence in 2005 of a $38 million unrealized loss on the interest rate portfolio in 2004.

The decrease in power and gas unrealized mark-to-market gains primarily results from the impact of cash flow hedge accounting, which was prospectively applied to certain of Power’s derivative contracts beginning October 1, 2004. Net unrealized gains of $711 million related to the effective portion of the hedges are reported in *accumulated other comprehensive loss* in 2005 compared to $15 million in 2004. If Power had not applied cash flow hedge accounting in 2005, we would have reported the $711 million in *revenues* instead of in *accumulated other comprehensive loss*. Also in 2005, Power recognized losses of $6.8 million representing a correction of unrealized losses associated with a prior year. Our management concluded that the effects of this correction are not material to prior periods, 2005 results, or our trend of earnings. Partially offsetting these decreases is the effect of a greater increase in forward power prices on a greater volume of power purchase contracts in 2005 compared to 2004, resulting in increased unrealized mark-to-market gains on net power derivatives that are not accounted for as cash flow hedges.

The absence in 2005 of the unrealized loss on the interest rate portfolio is due to the termination and liquidation of all remaining interest-rate derivatives in fourth quarter 2004. A decrease in forward interest rates caused unrealized losses in the interest rate portfolio in 2004.

The $77 million increase in Power's *cost of sales* is primarily due to an increase in power and natural gas costs of $563 million, partially offset by a decrease in crude and refined products costs of $486 million. Power and natural gas costs increased primarily due to a 32 percent increase in average power purchase prices and a 44 percent increase in average natural gas purchase prices, partially offset by a 29 percent decrease in power purchase volumes. Hurricane Katrina, among other factors, contributed to the increase in prices. Costs in 2005 include approximately $8 million in purchases due to an outage at an electric generating facility that Power has access to via a fuel conversion service agreement. A 2004 reduction to certain contingent loss accruals of $10.4 million associated with power marketing activities in California during 2000 and 2001 also contributes to the increase in costs. Costs in 2004 include $486 million of crude and refined products costs, which are absent in 2005 due to the sale of the refined products business in 2004. Costs in 2004 also reflect a $13 million payment made to terminate a nonderivative power sales contract.

SG&A expenses decreased primarily due to decreased employee incentive compensation and decreased costs for outside services. A $9.7 million reduction of allowance for bad debts resulting from the sale of certain receivables to a third party also contributed to the decrease in *SG&A expenses*. *SG&A expenses* in 2004 include a $6.3 million reduction of allowance for bad debts resulting from a 2004 settlement with certain California utilities.

Other (income) expense — net in 2005 includes:

- An $82.2 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);
- A $4.6 million accrual for a regulatory settlement;
- A $23 million impairment of an equity investment (see Note 3 of Notes to Consolidated Financial Statements).

Other (income) expense — net in 2004 includes $6.1 million in fees related to the sale of certain receivables to a third party.

Although increased gas prices favorably impacted the fair value of Power's derivative natural gas hedges, the $333.4 million change from a *segment profit* to a *segment loss* is primarily due to the impact of cash flow hedge accounting. Additionally, plant outages and depressed margin spreads between the cost of gas and sales price of electricity contributed to lower *segment profit*. Accruals in 2005 for litigation contingencies and an impairment of an equity investment also contribute to the change in *segment profit (loss)*. Partially offsetting the decrease in *segment profit* is the absence in 2005 of unrealized and realized losses from the interest rate portfolio, which was liquidated in the fourth quarter of 2004.

2004 vs. 2003

The $3.9 billion decrease in *revenues* includes an approximately $4 billion decrease in *realized revenues* partially offset by a $41.9 million increase in *net forward unrealized mark-to-market gains*.

The approximately $4 billion decrease in *realized revenues* is primarily due to an approximately $3.1 billion decrease in power and natural gas realized revenues and an $862 million decrease in crude and refined products realized revenues.

Power and natural gas *realized revenues* decreased primarily due to a 47 percent decrease in power sales volumes, partially offset by a 5 percent increase in power sales prices. Sales volumes decreased because Power did not replace certain long-term physical contracts that expired or were terminated in 2003, primarily due to a lack of market liquidity and past efforts to reduce our commitment to the Power business. In addition, results for 2003 include a realized gain of $126.8 million based on the terms of an agreement to terminate a derivative contract. In addition, during 2003, revenues include the correction of the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001, resulting in the recognition of approximately $117 million in revenues attributable to prior periods. Refer to Note 1 of Notes to Consolidated Financial Statements for further information. Additionally, power and natural gas revenues in 2003 include a $37 million reduction for increased power rate refunds owed to the state of California as the result of FERC rulings. Crude and refined products revenues decreased primarily due to the sale of the crude gathering business in 2003, the sale of the refined products business in 2004 and the past efforts to exit this line of business.

In 2004, Power had *net forward unrealized mark-to-market gains* of $304 million, an increase of $41.9 million from 2003. The increase in unrealized gains is due to a $75 million increase associated with power and gas contracts, partially offset by an $11 million decrease in crude and refined products and a $22 million decrease in the interest rate portfolio. The increase in power and gas primarily results from a greater increase associated with near-term natural gas forward prices in 2004 than in 2003. Also contributing to the increase was the absence in 2004 of unrealized losses of approximately $70 million recognized in first quarter 2003 on contracts for which we elected the normal purchases and sales exception in second quarter 2003. Another factor contributing to the increase was the impact of cash flow hedge accounting, which was prospectively applied to certain of Power's forecasted transactions beginning October 1, 2004. A net loss of $15 million related to the effective portion of the hedges was reported in *accumulated other comprehensive income* in 2004. The decrease in crude and refined products primarily results from the sale of the crude gathering business in 2003, the sale of the refined products business in 2004 and the past efforts to exit this line of business. These activities led to a significantly smaller derivative position in 2004 than in 2003 which resulted in lower unrealized mark-to-market gains. The decrease in the interest rate portfolio is due primarily to a decrease in forward interest rates in first quarter 2004 compared to a slight increase in first quarter 2003.

The $3.9 billion decrease in Power's *cost of sales* is primarily due to a decrease in power and natural gas costs of approximately $3 billion and a decrease in crude and refined products costs of $904.5 million. Power and natural gas costs decreased primarily due to a 48 percent decrease in power purchase volumes, partially offset by a 2 percent increase in power prices. A $10.4 million reduction to certain contingent loss accruals in 2004 and a $13.8 million loss for other contingencies in 2003, both associated with power marketing activities in California during 2000 and 2001, contributed to the decrease in costs discussed above. Costs in 2004 also reflect a $13 million payment made to terminate a nonderivative power sales contract, which partially offsets the decrease in power and natural gas costs. Crude and refined products costs decreased primarily due to the sale of the crude gathering business in 2003, the sale of the refined products business in 2004, and other past efforts to exit this line of business.

The $40.8 million decrease in *SG&A expenses* is largely due to a $36 million decline in compensation expense, primarily as a result of staff reductions in prior years combined with the accelerated recognition of $13.6 million in 2003 of certain deferred compensation arrangements. In addition, a $6.3 million reduction of allowance for bad debts resulting from the 2004 settlement with certain California utilities and the absence of a $6.5 million bad debt charge associated with a termination settlement in 2003 also contributed to the decrease.

Other (income) expense — net in 2004 includes $6.1 million in fees related to the sale of certain receivables to a third party. *Other (income) expense — net* in 2003 includes a $188 million gain from the sale of an energy-trading contract and a $13.8 million gain from the sale of certain investments. These income items are partially offset by the effect of the following 2003 items:

- A $20 million charge for a settlement with the CFTC;
- Accruals of $19.5 million for power marketing activities in California in prior periods (see Note 15 of Notes to Consolidated Financial Statements);
- A $45 million impairment of goodwill;
- A $44.1 million impairment on a power generating facility (see Note 4 of Notes to Consolidated Financial Statements);

- A $14.1 million impairment associated with the Aux Sable partnership investment (see Note 3 of Notes to Consolidated Financial Statements).

The $58.4 million decrease in *segment profit* is primarily due to lower sales volumes and the absence in 2004 of income from certain terminated contracts and prior period adjustments and the effect of the other income changes noted above, partially offset by lower *SG&A expense*.

Gas Pipeline

Overview

We operate, through our Northwest Pipeline and Transco subsidiaries, approximately 14,600 miles of pipeline from the Gulf Coast to the northeast United States and from northern New Mexico to the Pacific northwest with a total annual throughput of approximately 2,600 trillion BTUs. Additionally, we hold a 50 percent interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream). This asset, which extends from the Mobile Bay area in Alabama to markets in Florida, has current transportation capacity of 1.1 billion cubic feet per day.

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 2005

Grays Harbor

Effective January 2005, Duke Energy Trading and Marketing, LLC (Duke) terminated its firm transportation agreement related to Northwest Pipeline's Grays Harbor lateral. In January 2005, Duke paid Northwest Pipeline $94 million for the remaining book value of the asset and the related income taxes. We and Duke have not agreed on the amount of the income taxes due Northwest Pipeline as a result of the contract termination. We have deferred the $6 million difference between the proceeds and net book value of the lateral pending resolution of the disputed early termination obligation.

On June 16, 2005, we filed a Petition for a Declaratory Order with the FERC requesting that it rule on our interpretation of our tariff to aid in resolving the dispute with Duke. On July 15, 2005, Duke filed a motion to intervene and provided comments supporting its position concerning the issues in dispute.

Gulfstream pipeline expansions

Gulfstream completed a major extension and began service under new contracts in 2005.

- In February, the 110-mile Phase II natural gas pipeline expansion was placed into service. This facilitated the increase of long-term transportation volumes by 350 million cubic feet per day.
- In June, Gulfstream began incremental natural gas transportation service of 400,000 dekatherms per day (Dth/d) for two major Florida utilities.
- In August, Gulfstream established transportation service of up to 48,000 Dth/d for an additional Florida utility.

With these additional agreements, Gulfstream's long-term transportation commitment is now approximately 69 percent of total pipeline capacity.

Litigation related to recovery of fuel costs

In August 2005, pursuant to a settlement agreement, we resolved all outstanding issues pertaining to a regulatory filing involving recovery of certain fuel costs in prior periods. As a result of this ruling, we recognized income of $14.2 million from the reversal of a related liability.

Central New Jersey Expansion Project

In November 2005, Transco began operation of the 3.5-mile Central New Jersey Expansion Project on our Transco natural gas pipeline system. The expansion provides an additional 105,000 Dth/d of firm natural gas transportation service in Transco's northeastern market area. The capacity has been fully subscribed by a single shipper for a twenty-year term.

Significant 2005 adjustments

Operating results for the year include:

- Adjustments of $17.7 million were recorded, reflected as a $12.1 million reduction of *costs and operating expenses* and a $5.6 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 was reduced by $17.1 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 our third-party 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 $37.3 million reflected as increases in *costs and operating expenses* related to $32.1 million of prior period accounting and valuation corrections for certain inventory items and an accrual of $5.2 million for contingent refund obligations.

Our management concluded that the effects of these adjustments are not material to our consolidated results for 2005 or prior periods, or to our trend of earnings.

Outlook for 2006

Filing of rate cases

During 2006, we will be focused on successfully filing rate cases for both Transco and Northwest Pipeline subsidiaries which are expected to result in new transportation and storage rates beginning in 2007.

FERC Order "Accounting for Pipeline Assessment Cost"

FERC Order *"Accounting for Pipeline Assessment Costs,"* effective January 1, 2006, requires FERC-regulated companies to expense certain pipeline integrity-related assessment costs that we have historically capitalized. As a result of this Order we anticipate expensing approximately $27 million to $35 million of costs expected to be incurred in 2006 that would have been capitalized prior to the Order becoming effective.

Northwest pipeline capacity replacement project

In September 2005, we received FERC approval to construct and operate approximately 80 miles of 36-inch pipeline loop, which will replace most of the capacity previously served by 268 miles of 26-inch pipeline in the Washington state area. The estimated cost of the project is $333 million, with an anticipated in-service date of November 1, 2006.

Colorado gas pipeline expansion

In January 2006, we filed an application with the FERC to construct a 38-mile expansion that would provide additional natural gas transportation capacity in northwest Colorado. The planned expansion would increase capacity by 450,000 Dth/d through the 30-inch diameter line and is estimated to cost $55 million. We are currently in discussions with shippers to determine the level of commitment and anticipate beginning service on the expansion in January 2007.

Leidy to Long Island expansion project

In December 2005, we filed an application with the FERC to construct an expansion of our existing facilities in the northeast United States. This project will provide 100,000 Dth/d of incremental firm capacity, which has been fully subscribed for a twenty-year primary term. The estimated capital cost of the project is approximately $121 million with three-quarters of that spending expected to occur in 2007. The expansion is expected to be in service by November 1, 2007.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2005	2004	2003
		(Millions)	
Segment revenues	$ 1,412.8	$ 1,362.3	$ 1,368.3
Segment profit	$ 585.8	$ 585.8	$ 555.5

During 2004, our management and decision-making control of certain regulated gas gathering assets were transferred from our Midstream segment to our Gas Pipeline segment. Consequently, the results of operations were similarly reclassified and all prior periods reflect this reclassification.

2005 vs. 2004

The $50.5 million, or 4 percent, increase in Gas Pipeline *revenues* is due primarily to $86 million higher revenues associated with exchange imbalance cash-out settlements (offset in *costs and operating expenses*). Partially offsetting this increase is $24 million lower transportation revenues due primarily to the termination of the Grays Harbor contract, and $11 million lower revenues associated with reimbursable costs, which are passed through to customers (offset in *costs and operating expenses* and *SG&A expenses*).

Costs and operating expenses increased $109 million, or 16 percent, due primarily to:

- An increase in costs of $86 million associated with exchange imbalances (offset in *revenues*);
- The increase in costs of $32.1 million due to prior period accounting and valuation corrections related to inventory, as previously discussed;
- An increase in operating and maintenance expense of $14 million due primarily to increased contract service costs, materials and supplies and rental fees;
- The increase in costs of $5.2 million due to an accrual for contingent refund obligations, as previously discussed.

Partially offsetting these increases are decreases due to:

- Income of $14.2 million associated with the resolution of the litigation related to recovery of gas costs;
- The cost reduction of $12.1 million due to adjusting the carrying value of certain liabilities as noted previously;
- Lower reimbursable costs of $5 million (offset in *revenues*).

SG&A expenses decreased approximately $38 million, or 31 percent, due to the $17.1 million reduction in pension costs to correct a prior period error, $6 million lower reimbursable costs (offset in *revenues*), and the reversal of $5.6 million of prior period accruals.

Comparative *segment profit* is unchanged from 2004. The following are significant components of 2005 segment profit:

- The reduction in pension costs of $17.1 million to correct a prior period error;
- An increase in Gulfstream equity earnings of $14 million due to the realization of a $4.6 million construction fee award on the completion of the Phase II expansion project coupled with increased revenues associated with the Gulfstream expansions;
- Income of $14.2 million from the reversal of the contingency related to recovery of gas costs;
- The $17.7 million reversal of prior period accruals;
- The increase in costs of $32.1 million due to prior period accounting and valuation corrections related to inventory;
- An increase in operating and maintenance expense of $14 million due primarily to increased contract service costs, materials and supplies and rental fees;
- A decrease in transportation revenue of $24 million due primarily to the termination of the Grays Harbor contract.

2004 vs. 2003

The $6 million decrease in Gas Pipeline *revenues* is due to the following:

- A decrease in revenue of $25 million associated with reimbursable costs, which are passed through to customers (offset in *costs and operating expenses* and *SG&A expenses*);
- A decrease in revenues of $12 million due to lower environmental mitigation credits;
- A decrease in revenue of $9 million due to less short-term revenues at Northwest Pipeline;
- A decrease in revenue of $5 million due to reduced commodity revenues at Transco.

Partially offsetting these revenue reductions is $46 million higher transportation revenue primarily from expansion projects.

Costs and operating expenses decreased $2 million due primarily to:

- A decrease in reimbursable costs of $18 million (offset in *revenues*);
- A decrease in expenses of $8.5 million related to adjustments to depreciation recognized in a prior period;
- A decrease in *depreciation, depletion and amortization* expense of $8 million related to capitalized environmental mitigation credits;
- The absence of a $4 million write-off of certain receivables at Transco in 2003.

These decreases were partially offset by:

- An increase in maintenance expense of $11 million;
- An increase in fuel expense of $10 million at Transco reflecting a reduction in pricing differentials on the volumes of gas used in operations as compared to 2003;
- An increase in costs of $7 million associated with exchange imbalances;
- An increase in regulatory charges of $5 million.

SG&A expenses decreased $11 million, or 9 percent, due primarily to $6 million lower reimbursable costs (offset in revenues) and $4 million lower rent resulting from the terms of a new office lease at Transco.

Other (income) expense — net in 2004 includes an approximate $9 million charge for the write-off of previously capitalized costs incurred on an idled segment of Northwest Pipeline's system that we determined will not be returned to service. *Other (income) expense — net* in 2003 includes a $25.6 million charge at Northwest Pipeline to write off capitalized software development costs for a service delivery system following a decision not to implement and $7.2 million of income at Transco resulting from a reduction of *accrued liabilities* for claims associated with certain producers as a result of settlements and court rulings (see Royalty indemnifications in Note 15 of Notes to Consolidated Financial Statements).

The $30.3 million, or 5 percent, increase in *segment profit*, which includes equity earnings and income (loss) from investments is due to the following:

- The absence of the 2003 $25.6 million charge discussed above;
- A $13.4 million increase in equity earnings due primarily from our investment in Gulfstream;
- A $12 million increase in *revenues*, excluding reimbursable costs that do not impact *segment profit*;
- A $5 million reduction in *SG&A expense*, excluding reimbursable costs that do not impact *segment profit*.

These increases to *segment profit* were partially offset by:

- A $9 million charge for the write-off of previously capitalized costs discussed above;
- A $9 million increase in *costs and operating expenses*, excluding reimbursable costs that do not impact *segment profit*;
- The absence of the 2003 $7.2 million of income resulting from a reduction of *accrued liabilities*.

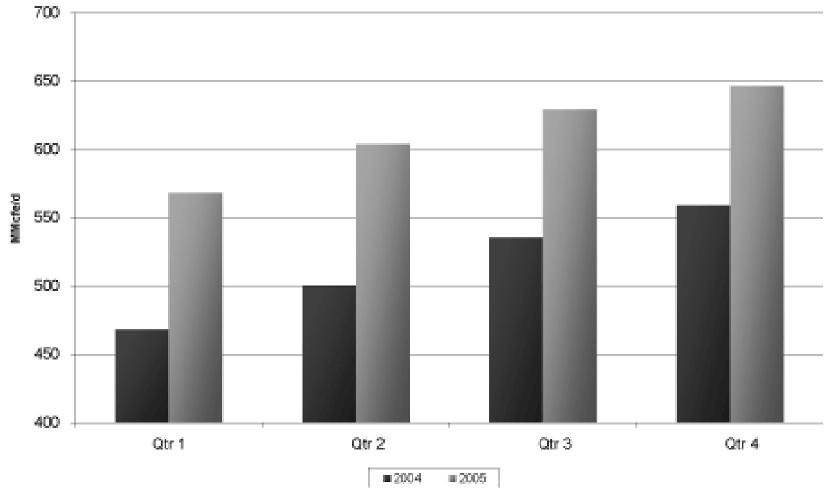
Exploration & Production

Overview of 2005

In 2005, we continued our strategy to rapidly expand the development of our significant drilling inventory located in our key growth basins. Our major accomplishments for the year include:

- Increased average daily domestic production levels by approximately 18 percent from last year, surpassing our goal of 15 percent. The domestic average daily production for the year ending December 31, 2005, was approximately 612 million cubic feet of gas equivalent (MMcfe) compared to 519 MMcfe in 2004.

Domestic Production Growth



2005 domestic production grew 18 percent or 93 MMcfe per day over 2004

- Benefited from higher market prices which, in turn, increased our net realized average prices received for production volumes sold. Net realized average prices include market prices, net of hedge positions, less gathering and transportation expenses. We realized net domestic average prices of $4.69 per thousand cubic feet of gas equivalent (Mcfe) compared with $3.17 per Mcfe in 2004, an increase of approximately 48 percent.
- Increased our development drilling program throughout 2005, surpassing annual drilling activities prior to 2005. We drilled 1,629 gross wells in 2005 compared to 1,395 in 2004. Capital expenditures for domestic drilling, development, and acquisition activity in 2005 were approximately $768 million compared to approximately $436 million in 2004.

The benefits of higher production volumes and higher net realized average prices were partially offset by increased operating costs and increased derivative hedge losses in 2005. The increase in operating costs was primarily the result of escalated overall production and maintenance activities among oil and gas producers, which increased competition for drilling rigs and services in our basins. The increase in hedge losses was primarily due to higher market prices associated with our NYMEX collars and fixed hedge positions.

Significant events of 2005

In March 2005, we entered into a contract for the operation of ten new drilling rigs, each for a lease term of three years. This arrangement supports our plan to accelerate the pace of natural gas development in the Piceance basin through both deployment of the additional rigs and also as a result of the drilling and operational efficiencies the new rigs are designed to deliver. We received our first two rigs in January and February 2006, and they have begun drilling. Although we originally expected to deploy one new rig per month beginning in November 2005, delays occurred as construction was impacted by the hurricanes experienced in the Gulf.

During the second quarter of 2005, we acquired an acreage position with a few producing wells in the Fort Worth basin in north-central Texas. In early January 2006, we increased our position in this basin. Our entry into this basin allows us to own an operated position that has potential for significant growth. It increases our diversification into the Mid-Continent region and allows us to use our horizontal drilling expertise to develop wells in the Barnett Shale formation.

Outlook for 2006

Our expectations for 2006 include:

- Continuing our development drilling program in our key basins of Piceance, Powder River, San Juan, and Arkoma. We have increased our planned capital expenditures for 2006 to between $950 million and $1.05 billion. The ten new drilling rigs are dedicated specifically to drilling activity in the Piceance basin.
- Increasing our domestic average daily production level of 612 MMcfe for the year ending December 31, 2005, by 15 to 20 percent by the end of 2006.

Approximately 299 MMcfe of our forecasted 2006 daily production of 750 to 825 MMcfe is hedged at prices that average $3.82 per Mcfe at a basin level. In addition, we entered into the following collar agreements:

- NYMEX collar agreement for approximately 50 MMcfe per day of our 2006 production at a floor price of $6.50 per Mcfe and a ceiling price of $8.25 per Mcfe;
- NYMEX collar agreement for approximately 15 MMcfe per day of our 2006 production at a floor price of $7.00 per Mcfe and a ceiling price of $9.00 per Mcfe;
- Northwest Pipeline/ Rockies collar agreement for approximately 50 MMcfe per day of our 2006 production at a floor price of $6.05 per Mcfe and a ceiling price of $7.90 per Mcfe at a basin level.

Risks to achieving our objectives include drilling rig availability, including timely deliveries of the contracted new rigs, as well as obtaining permits as planned for drilling.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2005	2004	2003
		(Millions)	
Segment revenues	$ 1,269.1	$ 777.6	$ 779.7
Segment profit	$ 587.2	$ 235.8	$ 401.4

2005 vs. 2004

The $491.5 million, or 63 percent increase in *revenues* is primarily due to an increase in domestic production revenues of $434 million during 2005 reflecting higher net realized average prices and higher production volumes sold. Also contributing to the increase is a $58 million increase in revenues from gas management activities and $13 million increased production revenues from our international operations. Partially offsetting these increases is a $10 million loss due to hedge ineffectiveness.

The increase in domestic production revenues primarily results from $319 million higher revenues associated with a 42 percent increase in net realized average prices for production sold as well as a $115 million increase associated with an 18 percent increase in average daily production volumes. The higher net realized average prices reflect the benefit of the lower volumes hedged in 2005 as compared to 2004 coupled with higher market prices for natural gas. The increase in production volumes primarily reflects an increase in the number of producing wells resulting from our successful 2005 drilling program.

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative forward sales contracts that economically lock in a price relating to a portion of our future production. Approximately 47 percent of domestic production in 2005 was hedged at a weighted average price of $3.99 per Mcfe at a basin level. In addition, we entered into the following collar agreements for 2005:

- NYMEX collar agreement for approximately 50 MMcfe per day for the first quarter of 2005 at a floor price of $7.50 per Mcfe and a ceiling price of $10.49 per Mcfe.

- NYMEX collar agreement for approximately 50 MMcfe per day for the second, third and fourth quarter of 2005 at a floor price of $6.75 per Mcfe and a ceiling price of $8.50 per Mcfe.
- Northwest Pipeline/ Rockies collar agreement for approximately 50 MMcfe per day for the fourth quarter of 2005 at a floor price of $6.10 per Mcfe and a ceiling price of $7.70 per Mcfe at a basin level.

These hedges are executed with our Power segment which, in turn, executes offsetting derivative contracts with unrelated third parties. Generally, Power bears the counterparty performance risks associated with unrelated third parties. Hedging decisions are made considering our overall commodity risk exposure and are not executed independently by Exploration & Production.

Total *costs and expenses* increased $147 million, primarily due to the following:

- $62 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;
- $16 million higher lease operating expense from the increased number of producing wells and generally higher industry costs;
- $23 million higher operating taxes primarily due to increased market prices and production volumes sold;
- $18 million higher *SG&A expenses* primarily due to higher compensation and increased staffing in 2005 in support of increased drilling and operational activity;
- $58 million higher gas management expenses associated with higher revenues from gas management activities;
- $11 million lower gain in 2005 than in 2004 on the sale of securities associated with our coal seam royalty trust that were previously purchased for resale.

These increased *costs and expenses* are partially offset by the absence in 2005 of a $15.4 million loss provision related to an ownership dispute on prior period production in 2004, a $7.9 million gain on the sale of an undeveloped leasehold position in Colorado in the first quarter of 2005, and a $21.7 million gain on the sale of certain outside operated properties in the Powder River basin area of Wyoming in the third quarter of 2005.

The $351.4 million increase in *segment profit* is primarily due to increased revenues from higher volumes and higher net realized average prices, as well as the gains on sales of assets, partially offset by higher expenses as discussed above. *Segment profit* also includes a $19 million increase reflecting higher revenues and equity earnings resulting from higher net realized oil and gas prices primarily from our Apco Argentina operations.

2004 vs. 2003

The $2.1 million, or less than 1 percent, decrease in *revenues* is primarily due to the absence of $24 million in income realized during 2003 from derivative instruments that did not qualify for hedge accounting, partially offset by an increase in domestic production revenues of $22 million during 2004. The increase in domestic production revenues primarily results from $49 million higher revenues associated with a 9 percent increase in production volumes partially offset by $27 million lower revenues associated with a 4 percent decrease in net realized average prices for production sold. Net realized average prices include the effect of hedge positions which were at prices below market levels. The increase in production volumes primarily reflects an increase in the number of producing wells resulting from our successful 2004 drilling program.

Approximately 77 percent of domestic production in 2004 was hedged at a weighted average price of $3.65 per MMcfe at a basin level.

Total *costs and expenses* increased $167 million, which includes the absence of $95 million in net gains on sales of assets occurring in 2003. The remaining increase in costs and expenses primarily reflects:

- $18 million higher depreciation, depletion and amortization expense primarily from increased production volumes as well as increased capitalized drilling costs that reflect greater levels of drilling and increased prices for tubular goods occurring in response to supply conditions in the worldwide steel market;
- $20 million higher lease operating expense associated with the higher number of producing wells and increased well maintenance activities, higher labor and fuel costs, and increased overhead payments to another operator;
- $17 million higher operating taxes due primarily to increased production volumes sold;
- A $16 million gain from the sales of securities, associated with a coal seam royalty trust, that were previously purchased for resale;
- A $15.4 million loss provision regarding an ownership dispute on prior period production.

The $165.6 million decrease in *segment profit* is due primarily to the absence of $95 million in net gains on sales of assets occurring in 2003, the increase in operating expenses, and the loss provision of $15.4 million relating to an ownership dispute on prior period production partially offset by the $16 million gain attributable to the sales of securities associated with our coal seam royalty trust that were purchased for resale. *Segment profit* also includes $25 million and $18 million related to international activities for 2004 and 2003, respectively. This increase is primarily driven by the improved operating results of Apco Argentina.

Midstream Gas & Liquids

Overview of 2005

In 2005, Midstream's ongoing strategy was 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 volumes to our assets by providing highly reliable service to our customers.

The following factors influenced our business in 2005:

Formation of Williams Partners L.P.

In February 2005, we formed Williams Partners L.P., a limited partnership, to complement our business strategy by providing access to a lower cost of capital to further expand the scale of our operations. On August 23, 2005, we completed our initial public offering (IPO) of five million common units of Williams Partners L.P. at a price of $21.50 per unit. The underwriters also fully exercised their option to purchase an additional 750,000 common units at the same price. Williams Partners L.P. owns a 40 percent equity investment in the Discovery gathering, transportation, processing and natural gas liquids (NGL) fractionation system; the Carbonate Trend sour gas gathering pipeline; three integrated NGL storage facilities near Conway, Kansas; and a 50 percent interest in an NGL fractionator near Conway, Kansas. Upon completion of the transaction, we held approximately 60 percent of the limited partnership units in Williams Partners L.P. and 100 percent of the general partner, Williams Partners GP, LLC.

Impact of hurricanes

Hurricanes Dennis, Katrina and Rita caused temporary shut-downs of most of our facilities and our producers' facilities in the Gulf Coast region, which reduced product flows resulting in lower segment profit of an estimated $17 million, which includes our insured property damage deductible, in the second half of 2005. Our major facilities resumed normal operations shortly after the passage of each hurricane except for our Devils Tower spar and Cameron Meadows gas processing plant. The Devils Tower deepwater spar was shut in on August 27, 2005, due to Hurricane Katrina and returned to service in early November. The Cameron Meadows natural gas processing plant near Johnson Bayou, Louisiana sustained significant damage from

Hurricane Rita on September 24, 2005. The plant returned to limited service in February 2006. We are pursuing a business interruption claim with our insurance carrier but have not recognized any amounts related to this pending claim.

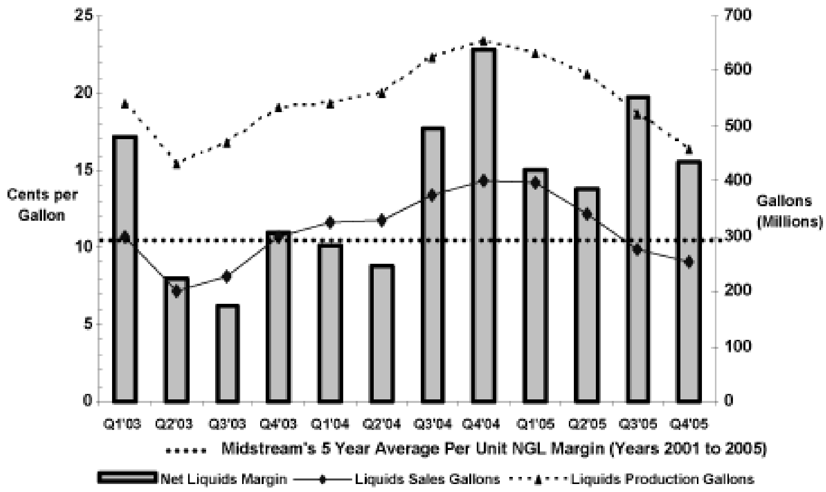
Expansion efforts in growth areas

Consistent with our strategy, we continued to expand our Midstream operations where we have large scale assets in growth basins. On October 5, 2005, we signed definitive agreements to construct, own and operate a 37-mile extension of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. This extension, estimated to cost $177 million, is expected to be ready for service by the third quarter of 2007. Also, in September we received Board approval to expand our existing gas processing plant located near Opal, Wyoming, by adding a fifth cryogenic train capable of processing up to 350 MMcfd. This plant expansion is expected to be in service by the second quarter of 2007 to begin processing gas from the Pinedale Anticline field.

Favorable commodity price margins

The actual realized NGL per unit margins at our processing plants exceeded Midstream's historical five-year annual average for the last six quarters. However, the industry benchmark for NGL fractionation spreads at Mont Belvieu, Texas was 40 percent below 2004 fractionation spreads. The geographic diversification of Midstream assets contributed significantly to our actual realized unit margins exceeding the industry benchmark at Mont Belvieu for gas processing spreads. The largest impact is realized at our western United States gas processing plants, which benefit from lower regional market natural gas prices. A decline in volumes in recent quarters is largely due to the third quarter impact of summer hurricanes on our Gulf Coast facilities as well as lower fourth quarter NGL recoveries at our West region plants. The lower NGL recoveries in the West were the result of intermittent periods in which the spread between NGL and natural gas prices was such that it was uneconomical to recover NGLs.

Domestic Gathering and Processing
Net Per Unit NGL Margin with Production and Sales Volumes by Quarter



Outlook for 2006

The following factors could impact our business in 2006 and beyond.

- As evidenced in recent years, natural gas and crude oil markets are highly volatile despite above average margins at our gas processing plants in recent years. Although NGL margins earned at our gas processing plants in 2005 were above the five-year average, we expect unit margins in 2006 to trend downward towards historical averages.
- Both gathering and processing volumes at our facilities are also expected to be at or above levels of previous years due to continued strong drilling activities in our core basins. 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.
- In 2006, we will continue to invest in facilities in the growth basins in which we provide services. The phase I expansion of our Wamsutter gathering system is scheduled to be operational during the first quarter of 2006.
- Based on recent market price forecasts, we anticipate olefins unit margins to be somewhat lower than 2005 levels.
- As disclosed in the critical accounting policies and estimates section of this Item 7, it is possible that our investment in our Canadian olefins assets may not be recoverable without modification to or a renegotiation of key terms in an off-gas processing agreement. We are evaluating our alternatives and will continue to monitor the recoverability of our investment.
- We expect continued growth in the deepwater areas of the Gulf of Mexico to contribute to, and become a larger component of, our future segment revenues and segment profit. We expect these additional fee-based revenues to lower our proportionate exposure to commodity price risks.
- 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.

Year-Over-Year Results

	Years Ended December 31,		
	2005	2004	2003
		(Millions)	
Segment revenues	$ 3,232.7	$ 2,882.6	$ 2,784.8
Segment profit (loss)			
Domestic gathering & processing	379.7	385.8	314.1
Venezuela	94.7	85.6	76.4
Other	62.3	134.0	(139.4)
Unallocated general and administrative expense	(65.5)	(55.7)	(53.8)
Total	$ 471.2	$ 549.7	$ 197.3

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

2005 vs. 2004

The $350.1 million increase in Midstream's *revenues* is largely due to higher commodity prices, offset slightly by lower sales volumes. Revenues associated with production of NGLs increased $72 million, of which $180 million is due to higher NGL prices partially offset by $108 million due to lower sales volumes. The decline in sales volumes in our Gulf Coast region is largely due to the impact of summer hurricanes, while the West region decline is largely due to the higher levels of NGL rejection as well as maintenance issues with our gas processing facility at Opal, Wyoming. Crude marketing revenues increased $196 million as a result of the start up of a deepwater pipeline in the second quarter of 2004 while the marketing of NGLs increased $58 million as a result of both higher prices and additional spot sales. Both of these increases are offset by similar increases in costs. In addition, fee revenues increased $21 million in part due to higher customer production volumes flowing to our West region and deepwater assets.

Costs and operating expenses increased $364.1 million primarily in support of higher revenues noted above. Costs related to the production of NGLs increased $92 million as a result of $100 million in higher natural gas purchases due largely to higher prices, partially offset by lower volumes. In addition, operating expenses increased $33 million mostly due to higher fuel expense and commodity costs associated with our NGL storage and fractionation business and higher depreciation expense. Similar to the impact to *revenues*, total *costs and operating expenses* also increased $196 million due to higher crude marketing purchases and $58 million related to the marketing of NGLs and additional spot purchases.

The $78.5 million decline in Midstream *segment profit* is primarily due to the absence of the $93.6 million gain from the Gulf Liquids' insurance arbitration award in 2004. The offsetting increase in segment profit is primarily due to higher fee revenues from our gathering and processing and Venezuela businesses and higher earnings from our investment in the Discovery Partnership, partially offset by lower net NGL margins and higher operating costs. A more detailed analysis of the segment profit of Midstream's various operations is presented below.

Domestic gathering & processing

The $6.1 million decrease in *domestic gathering and processing segment profit* includes a $30 million decline in the Gulf Coast region, largely offset by a $24 million increase in the West region.

The $24 million increase in our West region's *segment profit* primarily results from higher gathering and processing fee revenues, and the absence of an asset write-down and other 2004 charges, offset partially by higher operating expenses and lower net NGL margins. The significant drivers to these items are as follows:

- Gathering and processing fee revenues increased $18 million primarily as a result of higher average per-unit gathering and processing rates and higher volumes in the Rocky Mountain production area due to increased drilling activity. A portion of this increase is also due to the increase in volumes subject to fee-based processing contracts.

- *Other (income) expense — net* had a favorable variance of $10 million primarily due to the absence of the write-down of $7.6 million for an idle treating facility in 2004.

- Net NGL margins decreased $6 million due to a $17 million impact from a decline in sales volumes resulting from lower fourth quarter NGL recoveries caused by intermittent periods of uneconomical market commodity prices and a power outage and associated operational issues at our Opal, Wyoming facility. Net NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation expense. The impact of lower volumes is partially offset by an $11 million impact of higher per unit NGL margins.

The $30 million decrease in the Gulf Coast region's *segment profit* is primarily a result of higher operating and depreciation expenses and lower net liquids margins. The significant components of this decline include the following:

- Operating expenses increased $10 million primarily due to higher maintenance expenses related to our gathering assets, compressor overhauls, and an increase in hurricane-related costs of $2 million. Inspection and repair expenses related to the hurricanes are being recorded as incurred up to the level of our insurance deductible.

- Depreciation expense increased $13 million primarily due to placing in service our Devils Tower spar and associated deepwater gas and oil pipelines in May and June 2004, respectively.

- Liquids margins declined $14 million due to lower volumes, largely due to the impact of summer hurricanes, and the increase in natural gas prices. While revenues from the Devils Tower deepwater facility are recognized as volumes are delivered over the life of the reserves, cash payments from our customers are based on a contractual fixed fee received over a defined term. As a result, $44 million of cash received in 2005, which is included in cash flow from operations, was deferred at December 31, 2005 and will be recognized as revenue in periods subsequent to 2005. The total amount deferred for all years as of December 31, 2005 was $80 million.

Venezuela

Segment profit for our Venezuela assets increased $9.1 million as a result of higher plant volumes and higher equity earnings from our investment in the ACCROVEN partnership. The higher equity earnings are largely due to the renegotiation of a power supply contract and the absence of 2004 legal fees associated with the Jose Terminal.

Other

The $71.7 million decrease in *segment profit* of our other operations is largely due to the absence of the $93.6 million gain from the Gulf Liquids' insurance arbitration award and a $9.5 million gain on the sale of the Choctaw ethylene distribution assets in 2004 partially offset by $7 million in higher olefins and commodity margins, $6 million in higher earnings from our equity investment in the Discovery partnership, and the absence of a 2004 $16.9 million impairment charge also related to our equity investment in the Discovery partnership.

Unallocated general and administrative expense

The $9.8 million unfavorable variance for our *unallocated general and administrative expense* is primarily due to higher employee expenses and administrative costs associated with the creation of Williams Partners, L.P.

2004 vs. 2003

The $97.8 million increase in Midstream's *revenues* is primarily the result of favorable commodity prices on our gas processing and olefins businesses, largely offset by lower trading revenues resulting from the fourth-quarter 2003 sale of our wholesale propane business. Revenues associated with production of NGLs increased $417 million, of which $214 million is due to higher volumes and $203 million is due to higher NGL prices. Olefins revenues increased $223 million as a result of both higher market prices and higher volumes. In addition, our deepwater service revenues increased $9 million due to the addition of new infrastructure. Other factors affecting total revenues include approximately $1 billion in lower trading revenues resulting from the fourth-quarter 2003 sale of our wholesale propane business, partially offset by a $263 million increase as the result of marketing NGLs on behalf of our customers. Before 2004, our purchases of customers' NGLs were netted within revenues. In 2004, these purchases of customers' NGLs are included in costs and operating expenses which substantially offset the change in revenues. Of this $263 million increase, approximately $146 million results from the difference in financial reporting presentation; the remaining increase is due to higher NGL volumes and prices. Also partially offsetting the lower trading revenues is $141 million in higher crude sales associated with the 2004 startup of one of our deepwater pipelines, which is offset in costs and operating expenses.

Costs and operating expenses decreased $56 million primarily as a result of approximately $1 billion in lower trading costs due to the sale of our wholesale propane business in 2003. This decline was partially offset by $312 million in higher costs related to the production of NGLs and $157 million in higher costs related to the production of olefins products. These costs increased as a result of both the higher production volumes noted above and the higher prices for natural gas and olefins feedstock. Maintenance and depreciation expenses increased $33 million in large part due to newly constructed deepwater assets. Similar to the impact to revenues, total costs and operating expenses increased $263 million due to the marketing of NGLs on behalf of customers and $141 million in higher crude purchases related to the same deepwater pipeline mentioned above.

The $352.4 million increase in Midstream *segment profit* includes the $93.6 million gain from the Gulf Liquids' insurance arbitration award in 2004 and the absence of a $108.7 million impairment charge in 2003 related to these same assets, both of which are included in *other (income) expense — net,* within *operating income.* The remaining increase in *segment profit* is primarily due to higher NGL and olefins production volume and unit margins, higher service revenues, and reduced general and administrative expenses. These increases are partially offset by higher operating expenses and asset impairment charges. A more detailed analysis of *segment profit* of Midstream's various operations is presented below.

Domestic gathering & processing

The $71.7 million increase in *domestic gathering and processing segment profit* includes a $64.1 million increase in the West region and a $7.6 million increase in the Gulf Coast region.

The $64.1 million increase in our West region's *segment profit* reflects higher NGL volume and unit margins offset by lower fee revenues and higher operating expenses. Our West region's net NGL margins for 2004 increased $69 million compared to the same period in 2003. Net NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation expense. Average per unit NGL margins increased 49 percent and comprised $51 million of the increase in NGL margins. As a result of the higher spread between the prices of NGLs and natural gas, our West plants operated at near capacity and produced 21 percent higher volumes comprising the remaining $18 million increase in NGL net margins.

The $7.6 million increase in our Gulf Coast region's *segment profit* is due to higher NGL margins partially offset by lower fee revenues and higher depreciation expense. The significant components of the net increase include the following:

- Net NGL margins at our Gulf Coast gas processing plants increased $35 million due to a 101 percent increase in NGL production volumes which represented $28 million of the increase in margins. The significantly higher NGL volumes were driven by the favorable spread between NGL and natural gas prices coupled with the recently completed production handling infrastructure flowing additional deepwater gas production to our plants. Per unit margins in the Gulf Coast region increased 13 percent and comprised the remaining $7 million increase in net NGL margins.

- *Segment profit* from our deepwater assets declined $20 million primarily due to $29 million in higher costs associated with assets placed into service in the first two quarters of 2004 partially offset by $9 million in higher services revenues. The increase in *revenues* includes $22 million in incremental revenues from newly constructed assets partially offset by a $13 million decline in handling and gathering revenues due to lower production volumes on other deepwater assets substantially resulting from the effects of Hurricane Ivan. While revenues from the Devils Tower deepwater facility are recognized as volumes are delivered over the life of the reserves, cash payments from our customers are based on a contractual fixed fee received over a defined term. As a result, $36 million of cash received, which is included in cash flow from operations, was deferred at December 31, 2004 and will be recognized as revenue in periods subsequent to 2004.

Venezuela

The $9.2 million increase in *segment profit* for our Venezuelan assets is primarily due to the absence of the financial impact of a fire at the El Furrial facility that reduced revenues by $10 million in the first quarter of 2003.

Other

The $273.4 million increase in *segment profit* in our other businesses includes the $93.6 million Gulf Liquids insurance arbitration award and the absence of $108.7 million in Gulf Liquids impairment charges in 2003. The remaining increase is comprised of the following:

- Combined margins from our olefins businesses improved $66 million reflecting the overall improvement in olefins pricing and higher production volumes. Market prices for ethylene and propylene products increased due to higher demand and lower inventories. Production volumes increased as a result of increased spot sales and the new higher fixed margin contract at our Giesmar facility while our Canadian and Gulf Liquids volumes benefited from improved plant operations.

- The favorable variances above are partially offset by a 2004 $16.9 million impairment charge related to our equity investment in the Discovery partnership, reflecting management's assessment that there was an other-than-temporary decline in the value of this investment.

Other

Overview of 2005

As discussed below, the $105 million 2005 Other *segment loss* is primarily associated with our equity method investment in Longhorn. Shipping volumes on the Longhorn pipeline declined significantly during the second quarter of 2005 compared to those experienced in the first quarter. The decline was due primarily to the impact of significant changes in transportation pricing competition and economics in the wake of significantly higher crude oil prices. Longhorn management indicated that the shortfall in volumes was likely to continue and that continued operation as originally planned was no longer economically feasible. As a result, the owners and management of Longhorn began evaluating several alternatives for the future operation of Longhorn.

To ensure adequate liquidity to continue operations while assessing alternatives, during the third quarter of 2005 Longhorn obtained a $25 million bridge loan commitment from existing investors. The loan is secured by a first lien on the assets of Longhorn. We have fully funded our $10 million commitment of this loan, which has a one-year term and an interest rate of 14 percent. Our receivable related to this loan is included in *accounts and notes receivable* on the Consolidated Balance Sheet. The loan agreement allows for an additional $25 million loan, secured by the same first lien on the assets of Longhorn. All existing investors will have the opportunity to participate in funding the second $25 million increment. We do not expect to participate as a lender in this additional increment.

Based on management's outlook for Longhorn at the end of the second quarter, we assessed our investment in Longhorn to determine if there had been an other-than-temporary decline in its fair value. As a result, we recorded an impairment of $49.1 million during the second quarter of 2005. In the fourth quarter of 2005, management of Longhorn decided to pursue a strategy of the sale of Longhorn. As a result, Longhorn is negotiating a purchase and sale agreement. Based on initial indications from potential buyers, we determined that our Longhorn investment would require full impairment. Therefore, in fourth quarter 2005, we recorded a $38.1 million impairment to write off the remaining investment in Longhorn.

On April 1, 2005, we completed a contract to transfer our Longhorn operating agreement to a new operator in exchange for payments of approximately $285,000 a month, adjusted for inflation, over the next seven years. The transfer became effective May 1, 2005. Realization of the Longhorn operating agreement payments is dependent upon the continued operation of Longhorn. Any payments received as a result of the ongoing payment stream or through monetization of the contract will be recognized as income when received.

Outlook for 2006

Projected volumes indicate that Longhorn will continue to operate at a loss until a sale is complete. However, as a result of the full write-off of our investment in Longhorn during the fourth quarter of 2005, we will no longer recognize equity losses associated with this investment. We currently expect to receive full payment on the $10 million bridge loan from the proceeds of the sale.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2005	2004	2003
		(Millions)	
Segment revenues	$ 27.2	$ 32.8	$ 72.0
Segment loss	$ (105.0)	$ (41.6)	$ (50.5)

2005 vs. 2004

Other *segment loss* for 2005 includes $87.2 million of impairment charges, of which $38.1 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 $23.7 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.

Other *segment loss* for 2004 includes $11.8 million of accrued environmental remediation expense associated with the Augusta refinery. Also included in Other *segment loss* is $10.8 million of impairment charges related to our investment in Longhorn, $9.8 million of equity losses associated with our investment in Longhorn, and $6.5 million of net unreimbursed advisory fees related to the recapitalization of Longhorn.

2004 vs. 2003

Other *segment revenues* for 2003 includes approximately $22 million of revenues related to certain butane blending assets, which were sold during third quarter 2003.

Other *segment loss* for 2004 includes various items which are discussed above. Other *segment loss* for 2003 includes a $43.1 million impairment related to our investment in equity and debt securities of Longhorn.

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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, 2005. We have presented the fair value of assets and liabilities by the period in which we expect them to be realized.

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 36-60 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
$ —	$ (4)	$ —	$ —	$ —	$ (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 on an economic basis forecasted transactions. We have designated certain of these contracts as cash flow hedges of Power's forecasted purchases of gas, and purchases and sales of power related to its long-term structured contracts and owned generation and Exploration & Production's forecasted sales of natural gas production. We began applying cash flow hedge accounting in our Power business in the fourth quarter of 2004, after we decided to cease efforts to exit and to continue to operate the Power business. Many of these derivatives had an existing fair value prior to their designation as cash flow hedges. Certain of Power's other derivatives have not been designated as or do not qualify as SFAS 133 cash flow hedges. The chart below reflects the fair value of derivatives held for nontrading purposes as of December 31, 2005, for both the Power and Exploration & Production businesses. Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net liability value of $6 million as of December 31, 2005, which includes the existing fair value of the derivatives at the time of their designation as SFAS 133 cash flow hedges.

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 36-60 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
$ (219)	$ 68	$ 240	$ 17	$ —	$ 106

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 and power through 2010.

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 value of $102 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.

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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, 2005, we held collateral support, including letters of credit, of $607 million.

We also enter into netting agreements to mitigate counterparty performance and credit risk. During 2005 and 2004, we did not incur any significant losses due to recent counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of December 31, 2005, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 542.2	$ 572.2
Energy marketers and traders	3,930.1	7,568.6
Financial institutions	1,851.1	1,851.1
Other	.4	1.7
	$ 6,323.8	9,993.6
Credit reserves		(37.0)
Gross credit exposure from derivatives		$ 9,956.6

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of December 31, 2005, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 129.4	$ 142.1
Energy marketers and traders	401.1	976.7
Financial institutions	36.1	36.1
Other	.4	1.4
	$ 567.0	1,156.3
Credit reserves		(37.0)
Net credit exposure from derivatives		$ 1,119.3

(a) We determine investment grade primarily using publicly available credit ratings. We included 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. Power's 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. In 2006, we expect to continue to reduce debt through scheduled debt payments and exchanges, while maintaining liquidity from cash and unused revolving credit facilities of at least $1 billion. We are maintaining this level as we consider the potential impact of significant changes in commodity prices, contract margin requirements above current levels, unplanned capital spending needs and the need to meet near term scheduled debt payments. We expect to fund capital and investment expenditures, debt payments, dividends, and working-capital requirements through cash flow from operations, which is currently estimated to be between $1.6 billion and $1.9 billion in 2006, proceeds from debt issuances and sales of units of Williams Partners, L.P., as well as cash and cash equivalents on hand as needed.

We enter 2006 positioned for growth through disciplined investments in our natural gas businesses. Examples of this planned growth include:

- Gas Pipeline will continue to expand its system to meet the demand of growth markets. Additionally, Northwest Pipeline will construct an 80 mile pipeline loop, which will replace most of the capacity previously served by 268 miles of pipeline in the Washington state area.

- Exploration & Production's March 2005 operating lease agreement will provide access to ten new drilling rigs each for a lease term of three years that will allow us to accelerate the pace of developing our natural gas reserves in the Piceance basin through both deployment of the additional rigs and the rigs' designed drilling and operational efficiencies. We received our first two rigs in January and February 2006 and they have begun drilling.

- 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 billion to $2.2 billion in 2006. Of the total estimated capital expenditures for 2006, $950 million to $1.1 billion is for capital expenditures at Exploration & Production. Also within the total estimated expenditures for 2006 is approximately $616 million to $681 million for maintenance-related projects at Gas Pipeline, including pipeline replacement and Clean Air Act compliance. Commitments for construction and acquisition of property, plant and equipment are approximately $222 million at December 31, 2005.

In November 2005, we initiated an offer to induce conversion of up to $300 million of the 5.5 percent junior subordinated convertible debentures into our common stock. The conversion was executed in January 2006 and approximately $220.2 million of the debentures were exchanged for common stock. See Note 12 of Notes to Consolidated Financial Statements for further information.

We have proposed to sell an approximate 25 percent interest in our gathering and processing assets in the Four Corners area to Williams Partners L.P. The terms of this proposed transaction, including price, will be subject to the approval of our board of directors and the board of directors of the general partner of Williams Partners L.P.

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 economically hedged the price of natural gas for approximately 414 MMcfe per day of its expected 2006 production of 750 to 825 MMcfe per day. Power has entered into fixed forward sales contracts that economically cover substantially all of its fixed demand obligations through 2010.

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• Sensitivity of margin requirements associated with our marginable commodity contracts.

As of December 2005, we estimate our exposure to additional margin requirements over the next 360 days to be no more than $567 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).

Overview

Liquidity

Our internal and external sources of liquidity include cash generated from our operations, bank financings, proceeds from asset sales and issuance of long-term debt and equity securities. While most of our sources are available to us at the parent level, others are available to certain of our subsidiaries, including equity issuances from Williams 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, 2005 (Millions)
Cash and cash equivalents*	$ 1,597.2
Auction rate securities and other liquid securities	122.9
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion	64.5
Available capacity under our $1.275 billion secured revolving and letter of credit facility**	897.0
	$ 2,681.6

Additional Liquidity

Shelf registration for a variety of debt and equity securities	$ 2,200.0
Shelf registration for debt only available to Northwest Pipeline and Transco***	$ 350.0

* *Cash and cash equivalents* includes $320.7 million of funds received from third parties as collateral. The obligation for these amounts is reported as *customer margin deposits payable* on the Consolidated Balance Sheet.

** This facility is secured by the common stock of Transco and guaranteed by Williams Gas Pipeline Company, L.L.C. Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. Williams Partners L.P. has access to $75 million, to the extent not utilized by us that we guarantee.

*** The ability of Northwest Pipeline to utilize these registration statements for debt securities is restricted by certain covenants of its debt agreements. So long as our credit rating is below investment grade, Northwest Pipeline and Transco can only use their shelf registration statements to issue debt if such debt is guaranteed by us.

Financial ratios and credit ratings

One of our objectives for 2006 is to continue the improvement in our financial ratios, with the ultimate goal of achieving ratios comparable to investment grade rated companies at some point in the future. Our end-of-year debt to capitalization ratio is 58.7 percent in 2005, 61.6 percent in 2004 and 74.5 percent in 2003. We expect the ratio to be 55 to 57 percent for 2006. Debt includes *long-term debt* and *long-term debt due within one year*. Capitalization includes *long-term debt due within one year, long-term debt*, and *stockholders'* *equity*. If the improvement in our ratios continues, our credit ratings may improve. However, a decline in our financial ratios, or other adverse events, could result in a ratings decline. Current ratings are:

Current Senior Unsecured Debt Ratings

	Williams	Northwest Pipeline	Transco
Standard & Poor's	B+	B+	B+
Moody's Investors Service	B1	Ba2	Ba2
Fitch Ratings	BB	BB+	BB+

In mid-2005, Standard & Poor's raised our debt ratings outlook from stable to positive. 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 "B" rating indicates that Standard and Poor's believes the issuer has the capacity to meet its financial commitment on the obligation, but that adverse business, financial or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment to the obligation. Standard and Poor's may modify its ratings with a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

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" ranking indicates an obligation that is judged to have speculative elements and is subject to substantial credit risk. A "B" rating from Moody's signifies an obligation that is considered speculative and is subject to high 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" indicating a mid-range ranking, and "3" ranking at the lower end of the category.

In March 2006, Fitch raised our debt ratings outlook from stable to positive. 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.

See Note 11 of Notes to Consolidated Financial Statements for discussion of debt covenants and ratios.

	Year Ended December 31, 2005 (Millions)
Net cash provided (used) by:	
Operating activities	$ 1,449.9
Financing activities	36.5
Investing activities	(819.2)
Increase in cash and cash equivalents	$ 667.2

Operating Activities

Our 2005 *net cash provided by operating activities* decreased slightly from 2004 and increased by 88 percent from 2003. A primary driver in *net cash provided by operating activities* is *income from continuing operations*, which increased primarily as a result of higher gas production volumes and net average realized prices for production sold. Refer to Results of Operations in Item 7 for more detailed information regarding *income from continuing operations*. Also contributing to the increase in income from continuing operations is the reduction in interest expense due to lower average borrowing levels. Cash payments for interest decreased $224 million from 2004. In addition to the changes in results of operations, net cash inflows from margin deposits and customer margin deposits payable decreased significantly from 2004. In 2004, our Power subsidiary issued a significant number of letters of credit to replace its cash margin deposits. As the letters of credit were issued, the counterparties returned our cash margin deposits to us. Due to fewer letters of credit being issued to replace cash margin deposits in 2005 and 2003, we have fewer receipts of margin deposits than in 2004.

Other, including changes in noncurrent assets and liabilities, includes contributions to our tax-qualified pension plans of $52.1 million, $136.8 million and $42.8 million in 2005, 2004 and 2003, respectively. It is our policy to make annual contributions to our tax-qualified pension plans in an amount equal to the greater of the actuarially computed annual normal cost plus any unfunded actuarial accrued liability, amortized over approximately five years, or the minimum required contribution under existing tax laws. Additional amounts may be contributed to increase the funded status of the plans. In an effort to strengthen our funded status and take advantage of strong cash flows, we contributed approximately $41.1 million more than our funding policy required in 2005 and $98.9 million more than our funding policy required in 2004.

Financing Activities

During 2005, our *net cash provided (used) by financing activities* was a source of cash as compared to a use in 2004 and 2003. During 2005, we received approximately $273 million reported in *proceeds from issuance of common stock* resulting from the exercise of the FELINE PACS equity forward contracts. *Payments of long-term debt* was significantly lower in 2005 as compared to 2004 primarily due to the substantial completion of our debt reduction strategy in 2004. During January 2005, we retired $200 million of 6.125 percent notes issued by Transco, which matured January 15, 2005. During August 2005, 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 reported as *proceeds from sale of limited partner units of consolidated partnership*. During 2004, we repaid long-term debt through tender offers and early retirements. We also reduced our debt through our FELINE PACS exchange. This noncash exchange resulted in payments of fees and expenses reported as *premiums paid on tender offer, early debt retirements and FELINE PACS exchange*. During 2003, we repurchased our outstanding 9.875 percent cumulative convertible preferred shares. We also repaid the RMT note payable and we refinanced our long-term debt at more favorable rates. See Note 11 of Notes to Consolidated Financial Statements for more detailed information regarding financing activities.

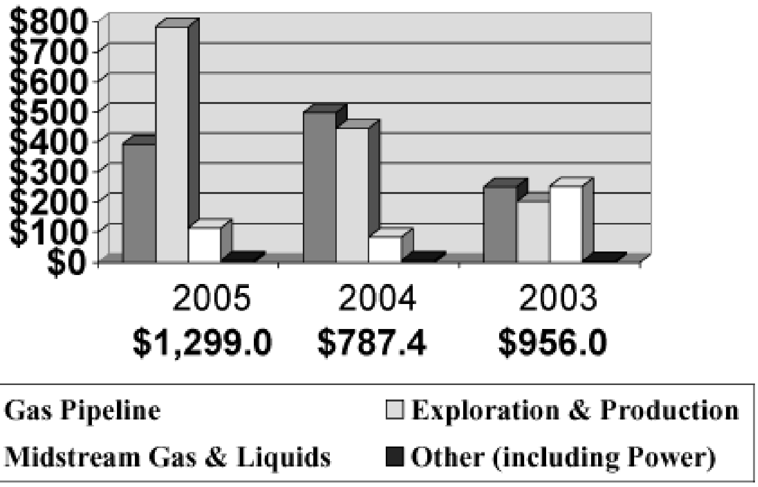
Dividends paid on common stock were increased from $.05 to $.075 per common share in third-quarter 2005 and totaled $143 million for the year ended December 31, 2005.

Investing Activities

During 2005, our *net cash provided (used) by investing activities* was a use of cash as compared to a source in 2004 and 2003. During 2005, we received $310.5 million in proceeds from the Gulfstream recapitalization. In January 2005, Northwest Pipeline received an $87.9 million contract termination payment, representing reimbursement of the net book value of the related assets. Refer to Gas Pipeline in Results of Operations in Item 7 for more information on the contract termination. In 2004, we sold all of our restricted investments resulting in proceeds of $851.4 million. Since our $800 million revolving and letter of credit facility that required 105 percent cash collateral has been replaced with a new revolving credit facility in January 2005, we are no longer required to hold the restricted investments. In 2004 and 2003, we had numerous asset sales resulting in proceeds in 2004 and 2003 of $877.8 million and $2,250.5 million, respectively. See Note 3 of Notes to Consolidated Financial Statements for more detailed information regarding investing activities.

In 2005, we began the year positioned for growth and have used additional cash flow for capital expenditures primarily at Exploration & Production. See a detail of capital expenditures by segment below.

Capital Expenditures
(Millions)



- Exploration & Production made capital expenditures in 2005 primarily for development drilling in the Piceance basin.
- Gas Pipeline made capital expenditures in 2005 primarily for normal maintenance and compliance.
- Midstream Gas & Liquids made capital expenditures in 2005 primarily for further expanding our systems in existing basins.

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

In January 2005, we terminated our two unsecured revolving and letter of credit facilities totaling $500 million and replaced them with two new facilities that contain similar terms but fewer restrictions. In September 2005, we also entered into two new revolving and letter of credit facilities that have a similar structure (see Note 11 of Notes to Consolidated Financial Statements).

We have provided a guarantee for obligations of Williams Partners L.P. under the $1.275 billion secured revolving and letter of credit facility.

We have various other guarantees and commitments which are disclosed in Notes 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 by period.

	2006	2007-2008	2009-2010	Thereafter	Total
			(Millions)		
Long-term debt, including current portion:					
Principal	$ 119	$ 1,112	$ 270	$ 6,237	$ 7,738
Interest	579	1,093	990	6,100	8,762
Capital leases	1	2	1	—	4
Operating leases(1)(5)	234	455	382	1,238	2,309
Purchase obligations:					
Fuel conversion and other service contracts(2)(5)	246	500	501	2,629	3,876
Other(5)	514	427	287	393(4)	1,621
Other long-term liabilities, including current portion:					
Physical and financial derivatives:(3)(5)	1,259	719	218	153	2,349
Other	72	100	30	1	203
Total	$ 3,024	$ 4,408	$ 2,679	$ 16,751	$ 26,862

(1) Excludes sublease income of $1.4 billion consisting of $260 million in 2006, $633 million in 2007-2008, and $518 million in 2009-2010. Includes a Power tolling agreement that is accounted for as an operating lease.

(2) Power has entered into certain contracts giving us the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States. Certain of Power's tolling agreements could be considered leases pursuant to the guidance in EITF Issue 01-8, "Determining Whether an Arrangement Contains a Lease," if in the future the agreements are modified for any reason. If deemed to be a capital lease, the net present value of the fixed demand payments would be reported on the Consolidated Balance Sheet consistent with other capital lease obligations, and as an asset in *property, plant and equipment — net*. See Note 1 of Notes to the Consolidated Financial Statements for further information.

(3) Although the amounts presented represent expected cash outflows, a portion of those obligations has previously been paid in accordance with third party margining agreements. As of December 31, 2005, we have paid $28 million in margins, adequate assurance, and prepayments related to the obligations included in this disclosure. In addition, the obligations for physical and financial derivatives are based on market information as of December 31, 2005. Because market information changes daily and has the potential to be volatile, significant changes to the values in this category may occur.

(4) Includes one year of annual payments totaling $2 million for contracts with indefinite termination dates.

(5) Expected offsetting cash inflows resulting from product sales or net positive settlements are not reflected in these amounts. The expected offsetting cash inflows as of December 31, 2005, are approximately $9.2 billion.

Effects of Inflation

Our operations in recent years have benefited from relatively low inflation rates. Approximately 48 percent of our gross property, plant and equipment is at Gas Pipeline and approximately 52 percent 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 specific price changes in oil and natural gas and related commodities than by changes in general inflation. Crude, refined product, natural gas, natural gas liquids and power 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 $64 million, all of which are recorded as liabilities on our balance sheet at December 31, 2005. We will seek recovery of approximately $18 million of the accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2005, we paid approximately $9 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $15 million in 2006 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, 2005, 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 $72 million in 2005 and are estimated to be between $40 million and $45 million subsequent to 2005. 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. *Qualitative and Quantitative 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 life of our operating assets.

The tables below provide information about our interest rate risk-sensitive instruments as of December 31, 2005 and 2004. 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.

	2006	2007	2008	2009	2010	Thereafter (1)	Total	Fair Value December 31, 2005
					(Dollars in millions)			
Long-term debt, including current portion(4):								
Fixed rate	$ 104	$ 381	$ 153	$ 41	$ 205	$ 6,179	$ 7,063	$ 7,952
Interest rate	7.7%	7.7%	7.8%	7.8%	7.8%	7.8%		
Variable rate	$ 15	$ 15	$ 563	$ 12	$ 12	$ 30	$ 647	$ 647
Interest rate(2)								

	2005	2006	2007	2008	2009	Thereafter (1)	Total	Fair Value December 31, 2004
					(Dollars in millions)			
Long-term debt, including current portion:								
Fixed rate	$ 235	$ 104	$ 381	$ 153	$ 41	$ 6,386	$ 7,300	$ 8,195
Interest rate	7.6%	7.7%	7.7%	7.7%	7.7%	7.7%		
Variable rate	$ 15	$ 15	$ 15	$ 563	$ 12	$ 42	$ 662	$ 662
Interest rate(3)								

(1) Including unamortized discount and premium.

(2) The weighted-average interest rate for 2005 is LIBOR plus 2 percent.

(3) The weighted-average interest rate for 2004 was LIBOR plus 2.1 percent.

(4) Excludes capital leases.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price of natural gas, electricity, refined products and natural gas liquids, as well as other market factors, such as market volatility and commodity price correlations, including correlations between crude oil and gas prices and between natural gas and power prices. 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 non-derivative 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. Only contracts that meet the definition of a derivative are carried at fair value on the balance sheet. Our value at risk for contracts held for trading purposes was approximately $4 million at December 31, 2005, and $1 million at December 31, 2004. During the year ended December 31, 2005, our value at risk for these contracts ranged from a high of $6 million to a low of $1 million.

Nontrading

Our nontrading portfolio consists of 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
Power	• Natural gas purchases and sales • Electricity purchases and sales

The value at risk for contracts held for nontrading purposes was $17 million at December 31, 2005, and $29 million at December 31, 2004. During the year ended December 31, 2005, our value at risk for these contracts ranged from a high of $34 million to a low of $17 million. Certain of the contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 133. We do not consider the underlying commodity positions to which the cash flow hedges relate in our value-at-risk model. Therefore, value at risk does not represent economic losses that could occur on a total nontrading portfolio that includes the underlying commodity positions.

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 $45 million and $52 million at December 31, 2005, and 2004, respectively. 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, 2005, could change by approximately $9.1 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 six percent of our net assets at December 31, 2005, and 2004. 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 $62 million at December 31, 2005.

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, 2005. 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, 2005, Williams' internal control over financial reporting is effective based on those criteria.

Ernst & Young, LLP, our independent registered public accounting firm, has issued an audit report on our assessment of the company's internal control over financial reporting. A copy of this report 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 management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that The Williams Companies, Inc. maintained effective internal control over financial reporting as of December 31, 2005, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management's assessment that The Williams Companies, Inc. maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, The Williams Companies, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, 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, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005 of The Williams Companies, Inc. and our report dated March 6, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
March 6, 2006

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, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005. 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, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, 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 the second paragraph of the *"Asset retirement obligations"* section in Note 9 to the consolidated financial statements, effective December 31, 2005, the Company adopted FASB Interpretation No. 47, *"Accounting for Conditional Asset Retirement Obligations."* Also as explained in Notes 1 and 9 to the consolidated financial statements, effective January 1, 2003, the Company adopted Emerging Issues Task Force Issue No. 02-3, *"Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities"* (see the *"Energy commodity risk management and trading activities"* section in Note 1) and Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations"* (see the third paragraph of the *"Asset retirement obligations"* section in Note 9).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 6, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
March 6, 2006

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF OPERATIONS

	Years Ended December 31, 2005	2004	2003
	(Millions, except per-share amounts)		
Revenues:			
Power	$ 9,093.9	$ 9,272.4	$ 13,195.5
Gas Pipeline	1,412.8	1,362.3	1,368.3
Exploration & Production	1,269.1	777.6	779.7
Midstream Gas & Liquids	3,232.7	2,882.6	2,784.8
Other	27.2	32.8	72.0
Intercompany eliminations	(2,452.1)	(1,866.4)	(1,549.3)
Total revenues	12,583.6	12,461.3	16,651.0
Segment costs and expenses:			
Costs and operating expenses	10,871.0	10,751.7	15,004.3
Selling, general and administrative expenses	325.4	355.5	421.3
Other (income) expense — net	61.2	(51.6)	(21.3)
Total segment costs and expenses	11,257.6	11,055.6	15,404.3
General corporate expenses	154.9	119.8	87.0
Operating income (loss):			
Power	(236.8)	86.5	145.3
Gas Pipeline	542.2	557.6	539.6
Exploration & Production	568.4	223.9	392.5
Midstream Gas & Liquids	446.6	552.2	178.0
Other	5.6	(14.5)	(8.7)
General corporate expenses	(154.9)	(119.8)	(87.0)
Total operating income	1,171.1	1,285.9	1,159.7
Interest accrued	(671.7)	(834.4)	(1,293.5)
Interest capitalized	7.2	6.7	45.5
Investing income	23.7	48.0	73.2
Early debt retirement costs	(0.4)	(282.1)	(66.8)
Minority interest in income of consolidated subsidiaries	(25.7)	(21.4)	(19.4)
Other income — net	27.1	21.8	38.5
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	531.3	224.5	(62.8)
Provision (benefit) for income taxes	213.9	131.3	(5.3)
Income (loss) from continuing operations	317.4	93.2	(57.5)
Income (loss) from discontinued operations	(2.1)	70.5	326.6
Income before cumulative effect of change in accounting principles	315.3	163.7	269.1
Cumulative effect of change in accounting principles	(1.7)	—	(761.3)
Net income (loss)	313.6	163.7	(492.2)
Preferred stock dividends	—	—	29.5
Income (loss) applicable to common stock	$ 313.6	$ 163.7	$ (521.7)
Basic earnings (loss) per common share:			
Income (loss) from continuing operations	$ .55	$ .18	$ (.17)
Income (loss) from discontinued operations	—	.13	.63
Income before cumulative effect of change in accounting principles	.55	.31	.46
Cumulative effect of change in accounting principles	—	—	(1.47)
Net income (loss)	$ .55	$ .31	$ (1.01)
Weighted-average shares (thousands)	570,420	529,188	518,137
Diluted earnings (loss) per common share:			
Income (loss) from continuing operations	$ .53	$ .18	$ (.17)
Income (loss) from discontinued operations	—	.13	.63
Income before cumulative effect of change in accounting principles	.53	.31	.46
Cumulative effect of change in accounting principles	—	—	(1.47)
Net income (loss)	$ .53	$ .31	$ (1.01)
Weighted-average shares (thousands)	605,847	535,611	518,137

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

	December 31, 2005	December 31, 2004
	(Dollars in millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,597.2	$ 930.0
Restricted cash	92.9	77.4
Accounts and notes receivable (net of allowance of $86.6 in 2005 and $98.8 in 2004)	1,613.8	1,422.8
Inventories	272.6	261.1
Derivative assets	5,299.7	2,961.0
Margin deposits	349.2	131.7
Assets of discontinued operations	12.8	13.6
Deferred income taxes	241.0	89.0
Other current assets and deferred charges	218.1	157.0
Total current assets	9,697.3	6,043.6
Restricted cash	36.5	35.3
Investments	887.8	1,316.2
Property, plant and equipment — net	12,409.2	11,886.8
Derivative assets	4,656.9	3,025.3
Goodwill	1,014.5	1,014.5
Other assets and deferred charges	740.4	671.3
Total assets	$ 29,442.6	$ 23,993.0
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,360.6	$ 1,043.2
Accrued liabilities	1,121.9	974.0
Customer margin deposits payable	320.7	17.7
Liabilities of discontinued operations	1.2	1.6
Derivative liabilities	5,523.2	2,859.3
Long-term debt due within one year	122.6	250.1
Total current liabilities	8,450.2	5,145.9
Long-term debt	7,590.5	7,711.9
Deferred income taxes	2,508.9	2,470.1
Derivative liabilities	4,331.1	2,735.7
Other liabilities and deferred income	920.3	873.8
Contingent liabilities and commitments (Note 15)		
Minority interests in consolidated subsidiaries	214.1	99.7
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 579.1 million and 563.8 million shares issued at December 31, 2005 and 2004, respectively)	579.1	563.8
Capital in excess of par value	6,327.8	6,005.9
Accumulated deficit	(1,135.9)	(1,306.5)
Accumulated other comprehensive loss	(297.8)	(244.2)
Other	(4.5)	(21.9)
	5,468.7	4,997.1
Less treasury stock, at cost (5.7 million shares of common stock in 2005 and 2004)	(41.2)	(41.2)
Total stockholders' equity	5,427.5	4,955.9
Total liabilities and stockholders' equity	$ 29,442.6	$ 23,993.0

See accompanying notes.

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THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	Preferred Stock	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Other	Treasury Stock	Total
				(Dollars in millions)				
Balance, December 31, 2002	$ 271.3	$ 522.5	$ 5,177.2	$ (884.3)	$ 33.8	$ (30.3)	$ (41.2)	$ 5,049.0
Comprehensive loss:								
Net loss — 2003	—	—	—	(492.2)	—	—	—	(492.2)
Other comprehensive loss:								
Net unrealized losses on cash flow hedges, net of reclassification adjustments	—	—	—	—	(236.9)	—	—	(236.9)
Net unrealized depreciation on marketable equity securities, net of reclassification adjustments	—	—	—	—	(7.4)	—	—	(7.4)
Foreign currency translation adjustments	—	—	—	—	77.0	—	—	77.0
Minimum pension liability adjustment	—	—	—	—	12.5	—	—	12.5
Total other comprehensive loss								(154.8)
Total comprehensive loss								(647.0)
Redemption of 9.875 percent cumulative convertible preferred stock (1.5 million shares)	(271.3)	—	—	—	—	—	—	(271.3)
Cash dividends — Common stock ($.04 per share)	—	—	—	(20.8)	—	—	—	(20.8)
Preferred stock ($20.14 per share)	—	—	—	(29.5)	—	—	—	(29.5)
Repayments of stockholders' notes	—	—	—	—	—	2.3	—	2.3
Stock award transactions, including tax benefit		1.5	17.9	—	—	—	—	19.4
Balance, December 31, 2003	—	524.0	5,195.1	(1,426.8)	(121.0)	(28.0)	(41.2)	4,102.1
Comprehensive income:								
Net income — 2004	—	—	—	163.7	—	—	—	163.7
Other comprehensive loss:								
Net unrealized losses on cash flow hedges, net of reclassification adjustments	—	—	—	—	(142.7)	—	—	(142.7)
Net unrealized appreciation on marketable equity securities, net of reclassification adjustments	—	—	—	—	1.9	—	—	1.9
Foreign currency translation adjustments	—	—	—	—	15.8	—	—	15.8
Minimum pension liability adjustment	—	—	—	—	1.8	—	—	1.8
Total other comprehensive loss								(123.2)
Total comprehensive income								40.5
Issuance of common stock and settlement of forward contracts as a result of FELINE PACS exchange (Note 12)	—	33.1	782.9	—	—	—	—	816.0
Cash dividends — Common stock ($.08 per share)	—	—	—	(43.4)	—	—	—	(43.4)
Allowance for and repayment of stockholders' notes	—	—	—	—	—	6.1	—	6.1
Stock award transactions, including tax benefit	—	6.7	27.9	—	—	—	—	34.6
Balance, December 31, 2004	—	563.8	6,005.9	(1,306.5)	(244.2)	(21.9)	(41.2)	4,955.9
Comprehensive income:								
Net income — 2005	—	—	—	313.6	—	—	—	313.6
Other comprehensive loss:								
Net unrealized losses on cash flow hedges, net of reclassification adjustments	—	—	—	—	(65.4)	—	—	(65.4)
Foreign currency translation adjustments	—	—	—	—	11.4	—	—	11.4
Minimum pension liability adjustment			—	—	.4	—		.4
Total other comprehensive loss								(53.6)
Total comprehensive income								260.0
Issuance of common stock and settlement of forward contracts as a result of FELINE PACS exchange (Note 12)	—	10.9	261.9	—	—	—	—	272.8
Cash dividends — Common stock ($.25 per share)	—	—	—	(143.0)	—	—	—	(143.0)
Allowance for and repayment of stockholders' notes	—	—	—	—	—	17.4	—	17.4
Stock award transactions, including tax benefit	—	4.4	60.0	—	—	—	—	64.4
Balance, December 31, 2005	$ —	$ 579.1	$ 6,327.8	$ (1,135.9)	$ (297.8)	$ (4.5)	$ (41.2)	$ 5,427.5

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31,		
	2005	2004	2003
		(Millions)	
OPERATING ACTIVITIES:			
Income (loss) from continuing operations	$ 317.4	$ 93.2	$ (57.5)
Adjustments to reconcile to cash provided by operations:			
Depreciation, depletion and amortization	740.0	668.5	657.4
Provision (benefit) for deferred income taxes	(45.3)	123.0	12.3
Provision for loss on investments, property and other assets	118.7	86.7	231.9
Net gain on dispositions of assets	(58.3)	(18.1)	(142.8)
Early debt retirement costs	.4	282.1	66.8
Minority interest in income of consolidated subsidiaries	25.7	21.4	19.4
Amortization of stock-based awards	12.7	9.5	27.1
Payment of deferred set-up fee and fixed rate interest on RMT note payable	—	—	(265.0)
Accrual for fixed rate interest included in RMT note payable	—	—	99.3
Amortization of deferred set-up fee and fixed rate interest on RMT note payable	—	—	154.5
Cash provided (used) by changes in current assets and liabilities:			
Restricted cash	(14.0)	(14.1)	(1.4)
Accounts and notes receivable	(240.9)	234.6	668.7
Inventories	(9.7)	(18.3)	88.6
Margin deposits and customer margin deposits payable	85.5	414.1	134.4
Other current assets and deferred charges	5.9	112.8	10.3
Accounts payable	232.5	(118.5)	(630.2)
Accrued liabilities	22.9	(218.9)	(245.8)
Changes in current and noncurrent derivative assets and liabilities	173.9	(160.4)	(350.0)
Changes in noncurrent restricted cash	—	86.5	17.6
Other, including changes in noncurrent assets and liabilities	82.5	(112.0)	92.1
Net cash provided by operating activities of continuing operations	1,449.9	1,472.1	587.7
Net cash provided by operating activities of discontinued operations	—	15.8	182.4
Net cash provided by operating activities	1,449.9	1,487.9	770.1
FINANCING ACTIVITIES:			
Payments of notes payable	—	(3.3)	(960.8)
Proceeds from long-term debt	—	75.0	2,006.5
Payments of long-term debt	(251.2)	(3,263.2)	(2,187.1)
Proceeds from issuance of common stock	309.9	20.6	1.2
Proceeds from sale of limited partner units of consolidated partnership	111.0	—	—
Dividends paid	(143.0)	(43.4)	(53.3)
Repurchase of preferred stock	—	—	(275.0)
Payments for debt issuance costs and amendment fees	(29.6)	(26.0)	(78.6)
Premiums paid on tender offer, early debt retirements and FELINE PACS exchange	(.4)	(246.9)	(57.7)
Dividends paid to minority interests	(20.7)	(5.9)	(19.8)
Changes in restricted cash	(2.7)	21.7	67.9
Changes in cash overdrafts	63.2	(21.4)	(29.7)
Other — net	—	(11.5)	(2.8)
Net cash provided (used) by financing activities of continuing operations	36.5	(3,504.3)	(1,589.2)
Net cash used by financing activities of discontinued operations	—	(1.2)	(94.8)
Net cash provided (used) by financing activities	36.5	(3,505.5)	(1,684.0)
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(1,299.0)	(787.4)	(956.0)
Proceeds from dispositions	47.3	12.0	603.9
Proceeds from contract termination payment	87.9	—	—
Changes in accounts payable and accrued liabilities	65.1	—	—
Purchases of investments/advances to affiliates	(116.1)	(2.1)	(150.4)
Purchases of auction rate securities	(224.0)	—	—
Purchases of restricted investments	—	(471.8)	(739.9)
Proceeds from sales of businesses	31.4	877.8	2,250.5
Proceeds from sales of auction rate securities	137.9	—	—
Proceeds from sale of restricted investments	—	851.4	351.8
Proceeds from dispositions of investments and other assets	64.2	94.1	128.6
Proceeds received on sale of note from WilTel	54.7	—	—
Payments received on notes receivable from WilTel	—	69.1	16.0
Proceeds from Gulfstream recapitalization	310.5	—	—
Other — net	20.9	(12.9)	15.5
Net cash provided (used) by investing activities of continuing operations	(819.2)	630.2	1,520.0
Net cash used by investing activities of discontinued operations	—	(.8)	(23.9)
Net cash provided (used) by investing activities	(819.2)	629.4	1,496.1
Increase (decrease) in cash and cash equivalents	667.2	(1,388.2)	582.2
Cash and cash equivalents at beginning of year	930.0	2,318.2	1,736.0
Cash and cash equivalents at end of year	$ 1,597.2	$ 930.0	$ 2,318.2

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: Power, Gas Pipeline, Exploration & Production, and Midstream.

Power is an energy services provider that buys, sells, stores, and transports energy and energy-related commodities, primarily power and natural gas, on a wholesale level. Power focuses on its objectives of minimizing financial risk, maximizing cash flow, meeting contractual commitments, executing new contracts to hedge its portfolio, and providing commodity marketing and supply functions that support our natural gas businesses.

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, which extends from the San Juan basin in northwestern New Mexico and southwestern Colorado to Oregon and Washington, and Transco, which extends from the Gulf of Mexico region to the northeastern United States. In addition, we own a 50 percent interest in Gulfstream. Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida.

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 in Argentina.

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 and transportation facilities in Venezuela, and assets in Canada, consisting primarily of a natural gas liquids extraction facility and a fractionation plant.

Basis of Presentation

The following are presented as discontinued operations in our financial statements (see Note 2):

- Retail travel centers concentrated in the midsouth, part of the previously reported Petroleum Services segment;
- Refining and marketing operations in the midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;
- Texas Gas Transmission Corporation, previously one of Gas Pipeline’s segments;
- Natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;
- Bio-energy operations, part of the previously reported Petroleum Services segment;
- General partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;
- The Colorado soda ash mining operations, part of the previously reported International segment;
- Certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream segment;

- Refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;
- Straddle plants in western Canada, previously part of the Midstream segment.

We have restated all segment information in the Notes to the Consolidated Financial Statements for all prior periods presented to reflect the discontinued operations noted previously. Certain other amounts have been reclassified to conform to the current classifications.

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

At December 31, 2004, all of the assets and liabilities of Gulf Liquids, which are not material to our Consolidated Balance Sheet, were classified as held for sale and included in *other current assets and deferred charges* and *accrued liabilities*. In second-quarter 2005, we decided to retain a portion of the Gulf Liquids operations and reclassified certain of the assets and liabilities from held for sale to held for use. The sale of the remaining assets held for sale closed on July 15, 2005.

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of our corporate parent and our majority-owned subsidiaries and investments. We apply the equity method of accounting for investments in 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

Management makes 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 and energy contracts;
- Environmental remediation obligations;
- Hedge accounting correlations;
- Realization of deferred income tax assets;
- Valuation of Exploration & Production’s reserves;
- Pension and postretirement valuation variables.

These estimates are discussed further throughout the accompanying notes.

Cash and cash equivalents

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

Restricted cash

Restricted cash within *current assets* consists primarily of collateral required by certain loan agreements for our Venezuelan operations, escrow accounts established to fund payments required by Power's California settlement (see Note 15), and an escrow account used to collect and manage margin dollars. *Restricted cash* within noncurrent assets relates primarily to certain borrowings by our Venezuelan operations 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 vehicle.

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. Consistent with our other securities that are classified as available-for-sale, 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 do not accrue a standard allowance when revenue is recognized. 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 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	0% - 3.80%
Storage facilities	1.05% - 2.50%
Onshore transmission facilities	2.35% - 5.00%
Offshore transmission facilities	0.85% - 1.50%

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	10 to 40
Power generation facilities	30
Transportation equipment	3 to 10
Building and improvements	10 to 45
Right of way	4 to 40
Office furnishings and computer software and hardware	3 to 20

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. Unproved properties are evaluated annually, or as conditions warrant, to determine any impairment in carrying value. *Depreciation, depletion and amortization* is provided under the units of production method on a field basis.

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 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, 2005, and 2004, 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 2005, 2004, and 2003 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.

Energy commodity risk management and trading activities

In 2002, the EITF reached a consensus on Issue No. 02-3 that rescinded EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." The consensus was applicable for fiscal periods beginning after December 15, 2002, and we applied the consensus effective January 1, 2003. As a result, beginning in 2003, we no longer apply fair value accounting to (1) energy and energy-related contracts that are not derivatives as defined in SFAS No. 133 and (2) physical commodity trading inventories. We reported the initial application of the consensus as a *cumulative effect of a change in accounting principle*, reducing *net income (loss)* by $762.5 million, net of a $471.4 million benefit for income taxes. The charge primarily consisted of the fair value of energy-related contracts, such as power tolling contracts, full requirements contracts, load serving contracts, storage contracts, transportation contracts and transmission contracts. These energy-related contracts do not meet the definition of a derivative and thus, beginning January 1, 2003, were no longer reported at fair value, but were rather reported under the accrual basis of accounting. The cumulative effect charge also included the amount by which the December 31, 2002, fair value of physical commodity trading inventories exceeded cost. We continue to carry derivatives at fair value. See further discussion on our accounting and reporting for derivatives in the following *Derivative instruments and hedging activities* section.

Derivative instruments and hedging activities

We report all derivatives at fair value on the Consolidated Balance Sheet in *derivative assets* and *derivative liabilities* as both current and noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual contracts.

We utilize derivatives to manage our commodity price risk. Derivative instruments held by us to manage commodity price risk 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 in exchange-traded or over-the-counter markets for which quoted prices in active periods exist. For contracts with terms that exceed the time period for which actively quoted prices are available, we must estimate commodity prices during the illiquid periods when determining fair value. We estimate commodity prices during 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.

For commodity derivatives that are not designated in a hedging relationship, we report changes in fair value currently in *revenues*. The accounting for changes in the fair value of commodity derivatives designated in a hedging relationship depends on the type of hedging relationship. We have elected the normal purchases and normal sales exception, available under SFAS No. 133, for certain commodity derivative contracts held by Power involving short-and long-term purchases and sales of a physical energy commodity. We reflect these contracts in *derivative assets* and *derivative liabilities*, as both current and noncurrent, at their fair value on the date of the election less the amount of that fair value realized during settlement periods subsequent to the election. We elected the normal purchases and normal sales exception on other commodity derivative contracts at their inception. We do not reflect these contracts on the Consolidated Balance Sheet.

In September 2004, we announced our decision to continue operating the Power business and cease efforts to exit that business. As a result of that decision, Power's derivative contracts became eligible for hedge accounting under SFAS No. 133. Power elected cash flow hedge accounting on a prospective basis beginning October 1, 2004, for certain qualifying derivative contracts.

For a derivative to qualify for designation in a hedging relationship, it has to 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 remains, and is expected to remain, highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. If a derivative ceases to be or is no longer expected to be highly effective, 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 hedge of a forecasted transaction (cash flow hedges), 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 income (loss)* associated with terminated derivatives, derivatives that cease to be highly effective hedges, and cash flow hedges that have been otherwise discontinued remain in *accumulated other comprehensive income (loss)* until the hedged item affects earnings or it is probable that the hedged item will not occur by the end of the originally specified time period or within two months thereafter. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If it becomes probable that the forecasted transaction will not occur, any gain or loss deferred in *accumulated other comprehensive income (loss)* is recognized in *revenues* at that time.

Certain gains and losses on derivative instruments included in the Consolidated Statement of Operations 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 cash flow hedges;
- 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. Our presentation of gains and losses is based on the following guidance:

- EITF 02-3;
- EITF Issue No. 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as defined in Issue No. 02-3;"
- EITF Issue No. 99-19 "Reporting Revenue Gross as a Principal versus as an Agent."

The EITF concluded in Issue No. 03-11 that judgment is required in determining whether realized gains and losses on physically settled derivatives not held for trading purposes should be reported on a gross or net basis. In reaching our conclusions on presentation, we evaluated the indicators in Issue No. 99-19, 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.

Assessment of energy-related contracts for lease classification

EITF 01-8, "Determining Whether an Arrangement Contains a Lease," became effective on July 1, 2003, and provides guidance for determining whether certain contracts such as transportation, transmission, storage, full requirements, and tolling agreements are executory service arrangements or leases pursuant to SFAS No. 13, "Accounting for Leases." The consensus is applied prospectively to arrangements consummated or modified after July 1, 2003. Prior to July 1, 2003, we accounted for energy-related contracts as executory service arrangements and continue this accounting unless a contract is subsequently modified and evaluated to be a lease. For executory service arrangements, the monthly demand payments are expensed as incurred. Certain of Power's tolling agreements will likely be considered leases under the consensus if the tolling agreements are ever modified. One tolling agreement was modified in 2004 and is accounted for as an operating lease. For tolling agreements that are modified and deemed to be operating leases, the monthly demand payments are expensed as incurred. If the monthly demand payments are not incurred on a straight-line basis, expense is nevertheless recognized on a straight-line basis. If such tolling agreements are modified and deemed to be capital leases, the net present value of the demand payments would be reported on the Consolidated Balance Sheet as *long-term debt* and as an asset in *property, plant and equipment — net*.

Gas Pipeline revenues

Revenues for sales of products are recognized in the period of delivery, and revenues from the transportation of gas are recognized in the period the service is provided. 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.

Revenues, other than Gas Pipeline, Exploration & Production, and energy commodity risk management and trading activities

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, "Accounting for the Impairment or Disposal of Long-Lived Assets," 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 on major projects during construction. Interest is capitalized on borrowed funds and, where regulation by the FERC exists, on internally generated funds. 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 (expense) — net* below *operating income*.

Additionally, Exploration & Production capitalizes interest on those construction projects with construction periods of at least three months and a total project cost in excess of $1 million. Exploration & Production capitalizes interest on equity investments when the investee is undergoing construction in preparation for its planned principal operations.

Employee stock-based awards

Employee stock-based awards are accounted for under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Fixed-plan common stock options generally do not result in compensation expense because the exercise price of the stock options equals the market price of the underlying stock on the date of grant. The plans are described more fully in Note 13. The following table illustrates the effect on *net income (loss)* and *earnings (loss) per share* if we had applied the fair value recognition provisions of SFAS No. 123, “Accounting for Stock-Based Compensation” (SFAS 123). Beginning January 1, 2006, we will adopt revised SFAS No. 123, “Share-Based Payment” (SFAS 123(R)). See further discussion in the *Recent Accounting Standards* section within this note.

	Years Ended December 31,		
	2005	2004	2003
		(Dollars in millions, except per share amount)	
Net income (loss), as reported	$ 313.6	$ 163.7	$ (492.2)
Add: Stock-based employee compensation expense included in the consolidated statement of operations, net of related tax effects	8.9	8.9	18.7
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(17.0)	(25.1)	(31.6)
Pro forma net income (loss)	$ 305.5	$ 147.5	$ (505.1)
Earnings (loss) per share:			
Basic — as reported	$ .55	$ .31	$ (1.01)
Basic — pro forma	$ .54	$ .28	$ (1.03)
Diluted — as reported	$ .53	$ .31	$ (1.01)
Diluted — pro forma	$ .52	$ .28	$ (1.03)

Pro forma amounts for 2005 include compensation expense from awards of our company stock made in 2005, 2004, 2003, and 2002 (see Note 13). Pro forma amounts for 2004 include compensation expense from awards made in 2004, 2003, 2002, and 2001. Also included in 2004 pro forma expense is $3.3 million of incremental expense associated with the stock option exchange program. Pro forma amounts for 2003 include compensation expense from awards made in 2003, 2002, and 2001. Also, included in 2003 pro forma expense is $2 million of incremental expense associated with the stock option exchange program.

Since compensation expense from stock options is recognized over the future years’ vesting period for pro forma disclosure purposes and additional awards are generally made each year, pro forma amounts may not be representative of future years’ amounts.

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 share

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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 Operations.

Issuance of equity of consolidated subsidiary

Sales of equity by a consolidated subsidiary are accounted for as capital transactions with the adjustment to capital in excess of par value. No gain or loss is recognized on these transactions.

Recent Accounting Standards

Stock-based awards

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS 123(R). The Statement requires that compensation costs for all share-based awards, including grants of employee stock options, to employees be recognized in the Consolidated Statement of Operations based on their fair values. Pro forma disclosure is no longer an alternative. The Statement, as issued by the FASB, was to be effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. However, in April 2005, the Securities and Exchange Commission (SEC) adopted a new rule that delayed the effective date for SFAS 123(R) to the beginning of the next fiscal year that begins after June 15, 2005. We intend to adopt the revised Statement on January 1, 2006.

The Statement allows either a modified prospective application or a modified retrospective application for adoption. We will use a modified prospective application for adoption and will apply the Statement to new awards and to awards modified, repurchased, or cancelled after January 1, 2006. Also, for unvested stock awards outstanding as of January 1, 2006, compensation costs for the portion of these awards for which the requisite service has not been rendered will be recognized as the requisite service is rendered after January 1, 2006. Compensation costs for these awards will be based on fair value at the original grant date as estimated for the pro forma disclosures under SFAS 123, as amended by SFAS No. 148, “Accounting for Stock-Based Compensation — Transition and Disclosure — an amendment of SFAS 123.” Additionally, a modified retrospective application requires restating periods prior to January 1, 2006 on a basis consistent with the pro forma disclosures required by SFAS 123, as amended by SFAS No. 148. Since we will use a modified prospective application, we will not restate prior periods.

We currently account for share-based awards to employees by applying the intrinsic value method in accordance with APB No. 25 and, as such, generally recognize no compensation cost for employee stock options. We currently recognize compensation cost for deferred share awards. Adoption of the Statement’s fair value method will have a significant impact on our results of operations. At January 1, 2006, we have approximately $56 million of compensation cost from outstanding unvested stock awards to be recognized as the requisite service is rendered, primarily in 2006 or 2007. Of the $56 million of compensation cost, approximately $23 million relates to stock options and approximately $33 million relates to stock awards where we currently recognize expense under APB No. 25 and related guidance. Stock-based awards will be granted during 2006. Our compensation cost as reported in pro forma disclosures required by SFAS 123, as amended by SFAS No. 148, may not be representative of compensation cost to be incurred in 2006 and beyond as the number and types of awards may differ and estimates of fair value may differ due to changes in the market price of our common stock, and to changing capital market and employee exercise behavior assumptions.

Certain of our stock awards currently result in compensation cost under APB No. 25 and related guidance. These stock awards are subject to vesting provisions and our policy is to adjust compensation cost for forfeitures when they occur. Upon the January 1, 2006, adoption of SFAS 123(R), we will reduce *net income (loss)* through *cumulative effect of a change in accounting principle* for previously recognized compensation cost, net of income taxes, related to the estimated number of these outstanding stock awards that are expected to be forfeited. The adjustment will not be material.

We currently present pro forma disclosure of *net income (loss)* and *earnings (loss) per share* as if compensation costs from all stock awards were recognized based on the fair value recognition provisions of SFAS 123. The Statement requires use of valuation techniques, including option pricing models, to estimate the fair value of employee stock awards. For pro forma disclosures, we currently use a Black-Scholes option pricing model in estimating the fair value of employee stock options and we intend to continue using a Black-Scholes option pricing model when we adopt SFAS 123(R).

FERC Order, "Accounting for Pipeline Assessment Cost"

On June 30, 2005, the FERC issued an Order, "Accounting for Pipeline Assessment Cost," to be effective January 1, 2006. The Order requires companies to expense certain pipeline integrity-related assessment costs that we have historically capitalized. We anticipate expensing approximately $27 million to $35 million of costs expected to be incurred in 2006 that would have been capitalized prior to the Order becoming effective.

Other recent accounting standards

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which will be applied prospectively for inventory costs incurred in fiscal years beginning after June 15, 2005. The Statement amends Accounting Research Bulletin (ARB) No. 43, Chapter 4, "Inventory Pricing," to clarify that abnormal amounts of certain costs should be recognized as current period charges and that the allocation of overhead costs should be based on the normal capacity of the production facility. The impact of this Statement on our consolidated financial statements will not be material.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29," which is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Statement amends APB Opinion No. 29, "Accounting for Nonmonetary Transactions." The guidance in APB Opinion No. 29 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged but includes certain exceptions to that principle. SFAS No. 153 amends APB Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. We will apply SFAS No. 153 as required.

In March 2005, the FASB issued a Staff Position (FSP) on a previously issued Interpretation (FIN). FSP FIN 46(R)-5, "Implicit Variable Interests under revised FASB Interpretation No. 46 (FIN 46(R)), *Consolidation of Variable Interest Entities,*" states that a reporting enterprise must consider implicit variable interests when applying the provisions of FIN 46(R). The FSP was effective in the second quarter of 2005 and did not have a material impact on our consolidated financial statements.

In April 2005, the FASB staff issued FSP FAS 19-1, "Accounting for Suspended Well Costs." This FSP amends SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," as it pertains to capitalizing the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. FSP FAS 19-1 provides that exploratory well costs should continue to be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making sufficient progress assessing the reserves and the economic and operational viability of the project. This FSP was effective beginning in the third quarter of 2005 and did not have a material impact on our consolidated financial statements.

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections — a replacement of APB Opinion No. 20 and FASB Statement No. 3," which is effective prospectively for reporting a change in accounting principle for fiscal years beginning after December 15, 2005. The Statement changes the reporting of a change in accounting principle to require retrospective application to prior periods unless explicit transition provisions provide otherwise. The Statement is effective for any existing accounting pronouncements, including those in the transition phase when it becomes effective. We will apply SFAS No. 154 as required.

In June 2005, the FASB ratified EITF Issue No. 04-10, "Determining Whether to Aggregate Operating Segments That Do Not Meet the Quantitative Thresholds." The consensus is effective for fiscal years ending after September 15, 2005, and does not affect the current presentation of our reportable operating segments.

In June 2005, the FASB ratified EITF Issue No. 05-2, "The Meaning of Conventional Convertible Debt Instrument in EITF Issue No. 00-19, *Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company's Own Stock."* The consensus is to be applied prospectively for new instruments entered into or existing instruments modified in periods beginning after June 29, 2005. We have outstanding 5.5 percent junior subordinated convertible debentures that were considered conventional convertible debt at issuance. This Issue does not currently impact these debentures. If we were to modify these debentures, we would have to evaluate the terms of the instruments after the modification to determine if they would remain a conventional convertible debt instrument or if the convertible features should be accounted for separately as a derivative.

In September 2005, the FASB ratified EITF Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." The consensus states that two or more inventory purchase and sales transactions with the same counterparty that are entered into in contemplation of one another should be combined as a single exchange transaction for purposes of applying APB Opinion No. 29. A nonmonetary exchange of inventory within the same line of business where finished goods inventory is transferred in exchange for the receipt of either raw materials or work in process inventory should be recognized at fair value by the entity transferring the finished goods inventory if fair value is determinable within reasonable limits and the transaction has commercial substance. All other nonmonetary exchanges of inventory within the same line of business should be recognized at the carrying amount of the inventory transferred. The Issue is effective for new arrangements entered into, and modifications or renewals of existing arrangements, beginning in the first reporting period beginning after March 15, 2006. We will apply this Issue beginning in the second quarter of 2006. We will assess the impact of this Issue on our consolidated financial statements.

In November 2005, the FASB issued FSP FAS 115-1 and FAS 124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments." The FSP provides guidance regarding when an investment is impaired, whether that impairment is other than temporary and measurement of the impairment loss. The FSP applies to debt and equity securities, except equity securities accounted for under the equity method. The FSP is effective for reporting periods beginning after December 15, 2005. We are currently evaluating the application of this FSP to determine its potential impact to our consolidated financial statements.

In February 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments, an amendment of FASB Statements No. 133 and 140." With regard to SFAS No. 133, this Statement permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, clarifies which interest-only and principal-only strips are not subject to the requirements of SFAS No. 133, and requires the holder of an interest in securitized financial assets to determine whether the interest is a freestanding derivative or contains an embedded derivative requiring bifurcation. SFAS No. 155 also amends SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," to eliminate a restriction on the passive derivative financial instruments that a qualifying special purpose entity may hold. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. We will assess the impact of this Statement on our Consolidated Financial Statements.

Emerging accounting issues

In addition to the recently issued accounting standards, there are several emerging accounting issues that could potentially impact our Consolidated Financial Statements in the future, including:

- Proposed SFAS on "Fair Value Measurements" (exposure draft);
- Proposed Interpretation on "Accounting for Uncertain Tax Positions — an interpretation of FASB Statement No. 109 (exposure draft);
- Accounting for Pensions and Other Postretirement Benefits (preliminary views).

We will monitor these emerging issues to assess any potential future impact on our consolidated financial statements.

Note 2. Discontinued Operations

The businesses discussed below represent components that have been sold as of December 31, 2005, and also are classified as discontinued operations. Therefore, their results of operations (including any impairments, gains or losses), financial position and cash flows have been reflected in the consolidated financial statements and notes as discontinued operations.

Summarized Results of Discontinued Operations

The following table presents the summarized results of discontinued operations for the years ended December 31, 2005, 2004, and 2003. *Income (loss) from discontinued operations before income taxes* for the year ended December 31, 2004, includes charges of approximately $153 million to increase our accrued liability associated with certain Quality Bank litigation matters (see Note 15). The *provision for income taxes* for the year ended December 31, 2004, is less than the federal statutory rate due primarily to the effect of net Canadian tax benefits realized from the sale of the Canadian straddle plants partially offset by the United States tax effect of earnings associated with these assets.

	2005	2004	2003
		(Millions)	
Revenues	$ —	$ 353.4	$ 2,614.6
Income (loss) from discontinued operations before income taxes	$ (3.9)	$ (121.3)	$ 197.5
(Impairments) and gain (loss) on sales — net	.5	200.5	277.7
Benefit (provision) for income taxes	1.3	(8.7)	(148.6)
Income (loss) from discontinued operations	$ (2.1)	$ 70.5	$ 326.6

2004 Completed Transactions

Canadian straddle plants

On July 28, 2004, we completed the sale of the Canadian straddle plants for approximately $544 million and recognized a $189.8 million pre-tax gain on the sale. These assets were previously written down to estimated fair value, resulting in impairments of $41.7 million during 2003 and $36.8 million in 2002. In 2004, the fair value of the assets increased substantially due primarily to renegotiation of certain customer contracts and a general improvement in the market for processing assets. These operations were part of the Midstream segment.

Alaska refining, retail and pipeline operations

On March 31, 2004, we completed the sale of our Alaska refinery, retail and pipeline operations for approximately $304 million. We received $279 million in cash at the time of sale and $25 million in cash during the second quarter of 2004. Based on information we obtained throughout the sales negotiations process, we recorded impairments of $8 million in 2003 and $18.4 million in 2002. We recognized a $3.6 million pre-tax gain on the sale during first quarter 2004. These operations were part of the previously reported Petroleum Services segment.

We are party to a pending matter involving pipeline transportation rates charged to our former Alaska refinery in prior periods. While we have no loss exposure in this matter, favorable resolution could result in a refund.

2003 Completed Transactions

Canadian liquids operations

During the third quarter of 2003, we completed the sales of certain gas processing, natural gas liquids fractionation, and storage and distribution operations in western Canada and at our Redwater, Alberta plant for total proceeds of $246 million. We recognized pre-tax gains totaling $92.1 million in 2003 on the sales. These operations were part of our Midstream segment.

Soda ash operations

On September 9, 2003, we completed the sale of our soda ash mining facility located in Colorado. During 2003, we recognized impairment charges of $17.4 million and a pre-tax loss on the sale of $4.2 million. We had recorded impairment charges of $133.5 million in 2002 and $170 million in 2001. The soda ash operations were part of the previously reported International segment.

Williams Energy Partners

On June 17, 2003, we completed the sale of our 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners for $512 million in cash and assumption by the purchasers of $570 million in debt. In December 2003, we received additional cash proceeds of $20 million following the occurrence of a contingent event. We recognized a total pre-tax gain of $310.8 million on the sale during 2003, including the $20 million of additional proceeds. We deferred an additional $113 million associated with certain environmental indemnifications we provided the purchasers under the sales agreement. In second quarter 2004, we settled these indemnifications with an agreement to pay $117.5 million over a four-year period (see Note 10). Williams Energy Partners was a previously reported segment.

Bio-energy facilities

On May 30, 2003, we completed the sale of our bio-energy operations for $59 million in cash. During 2003, we recognized a pre-tax loss of $5.4 million on the sale. We had recorded impairment charges totaling $195.7 million during 2002. These operations were part of the previously reported Petroleum Services segment.

Natural gas properties

On May 30, 2003, we completed the sale of natural gas exploration and production properties in the Raton Basin in southern Colorado and the Hugoton Embayment in southwestern Kansas. This sale included all of our interests within these basins. We recognized a $39.7 million pre-tax gain on the sale during 2003. These properties were part of the Exploration & Production segment.

Texas Gas

On May 16, 2003, we completed the sale of Texas Gas Transmission Corporation for $795 million in cash and the assumption by the purchaser of $250 million in existing Texas Gas debt. We recorded a $109 million impairment charge in 2003. No significant gain or loss was recognized on the subsequent sale. These operations were part of the Gas Pipeline segment.

Midsouth refinery

On March 4, 2003, we completed the sale of our refinery and other related operations located in Memphis, Tennessee, for $455 million in cash. We recognized a pre-tax gain on the sale of $4.7 million in the first quarter of 2003. During the second quarter of 2003, we recognized a $24.7 million pre-tax gain on the sale of an earn-out agreement we retained in the sale of the refinery. We had recorded impairment charges totaling $240.8 million during 2002. These operations were part of the previously reported Petroleum Services segment.

Williams travel centers

On February 27, 2003, we completed the sale of our travel centers for approximately $189 million in cash. We did not recognize a significant gain or loss on the sale. We had recorded impairment charges of $146.6 million in 2002 and $14.7 million in 2001. These operations were part of the previously reported Petroleum Services segment.

Note 3. Investing Activities

Investing Income

Investing income for the years ended December 31, 2005, 2004 and 2003, is as follows:

	2005	2004	2003
		(Millions)	
Equity earnings*	$ 65.6	$ 49.9	$ 20.3
Loss from investments*	(109.1)	(35.5)	(25.3)
Impairments of cost-based investments	(2.2)	(28.5)	(35.0)
Interest income and other	69.4	62.1	113.2
Total	$ 23.7	$ 48.0	$ 73.2

* Items also included in *segment profit* (see Note 18).

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

- An $87.2 million impairment of our investment in Longhorn, which is included in our Other segment;
- A $23 million impairment of our investment in Aux Sable, which is included in our Power segment.

Loss from investments for the year ended December 31, 2004, includes:

- A $10.8 million impairment of our Longhorn investment;
- $6.5 million net unreimbursed Longhorn recapitalization advisory fees;
- A $16.9 million impairment of our investment in Discovery, which is included in our Midstream segment.

Loss from investments for the year ended December 31, 2003, includes:

- A $43.1 million impairment of our Longhorn investment;
- A $14.1 million impairment of our investment in Aux Sable;
- A $13.5 million gain on the sale of stock in eSpeed Inc., which is included in our Power segment;
- An $11.1 million gain on sale of our investment in West Texas LPG Pipeline, L.P., which is included in our Midstream segment.

Impairments of cost-based investments for the year ended December 31, 2004, includes a $20.8 million impairment of our investment in an Indonesian toll road, primarily due to increased uncertainty of the Indonesian economy.

Impairments of cost-based investments for the year ended December 31, 2003, includes:

- A $13.5 million impairment of our investment in ReserveCo, a company holding phosphate reserves;
- A $13.2 million impairment of our investment in Algar Telecom S.A.

Interest income for the year ended December 31, 2003, includes approximately $34 million of interest income at Power as the result of certain FERC proceedings.

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Investments

Investments at December 31, 2005 and 2004, are as follows:

	2005	2004
	(Millions)	
Equity method:		
Gulfstream Natural Gas System, L.L.C. — 50%	$ 395.4	$ 726.1
Discovery Producer Services, L.L.C. — 60%* in 2005; 50% in 2004	227.9	184.2
Longhorn Partners Pipeline, L.P. — 21.3%	—	113.2
ACCROVEN — 49.3%	60.0	62.0
Aux Sable Liquid Products, L.P. — 14.6%	19.2	45.6
Petrolera Entre Lomas S.A. — 40.8%	51.9	44.9
Other	76.7	70.5
	831.1	1,246.5
Cost method:		
Various international funds	45.2	49.9
Other	11.5	19.8
	56.7	69.7
	$ 887.8	$ 1,316.2

* We own 20% directly and 40% indirectly through Williams Partners L.P., of which we own approximately 60%.

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

Dividends and distributions, including those discussed below, received from companies accounted for by the equity method were $447.4 million and $60 million in 2005 and 2004, respectively.

Gulfstream

We received a $310.5 million distribution from Gulfstream following its debt offering in October 2005. We also received dividends of $60.5 million from Gulfstream in 2005. These transactions reduced the carrying value of our investment.

Discovery

During 2005, our Midstream subsidiary acquired an additional 16.67 percent in Discovery, which was later reduced by 6.67 percent due to a nonaffiliated member exercising its purchase option. After these transactions, we hold a 60 percent interest in Discovery. 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.

Additionally, we contributed $40.7 million during 2005 to Discovery for planned capital expenditures. Each owner contributed an amount equal to their respective ownership percentage, thus having no impact on the overall ownership allocation. During 2005, we received $31.3 million in distributions from Discovery, which reduced the carrying value of our investment.

Longhorn

Shipping volumes on the Longhorn pipeline declined significantly during the second quarter of 2005 compared to those experienced in the first quarter. The decline was due primarily to the impact of significant changes in transportation pricing competition and economics in the wake of higher crude oil prices. Longhorn management indicated that the shortfall in volumes was likely to continue and that continued operation as originally planned was no longer economically feasible. As a result, the owners and management of Longhorn began evaluating several alternatives for the future operation of Longhorn.

Based on management's outlook for Longhorn at the end of the second quarter, we assessed our investment in Longhorn to determine if there had been an other-than-temporary decline in its fair value. As a result, we recorded an impairment of $49.1 million during the second quarter of 2005. In the fourth quarter of 2005, management of Longhorn decided to pursue a strategy of the sale of Longhorn. Based on initial indications from potential buyers, we determined that our Longhorn investment would require full impairment. Therefore, in fourth quarter 2005, we recorded a $38.1 million impairment to write off the remaining investment in Longhorn.

Aux Sable

During 2005, we decided to solicit sales offers for our investment in Aux Sable, a natural gas liquids extraction and fractionation facility. Based on initial indications of potential sales proceeds, management concluded that there is an other-than-temporary decline in fair value below carrying value. Accordingly, we recorded an impairment of $23 million.

Summarized Financial Position and Results of Operations of Equity Method Investments

Financial position at December 31:

	2005	2004
	(Millions)	
Current assets	$ 470.5	$ 345.1
Noncurrent assets	3,674.4	3,660.3
Current liabilities	362.0	357.4
Noncurrent liabilities	1,225.6	432.2

Results of operations for the years ended December 31:

	2005	2004	2003
		(Millions)	
Gross revenue	$ 1,337.5	$ 1,064.7	$ 753.9
Operating income	236.3	185.0	109.7
Net income	105.3	107.8	12.6

Guarantees on Behalf of Investees

We have guaranteed commercial letters of credit totaling $17 million on behalf of ACCROVEN. These expire in January 2007 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, 2005 and 2004.

Note 4. Asset Sales, Impairments and Other Accruals

Significant gains or losses from asset sales, impairments, and other accruals in *other (income) expense — net* within *segment costs and expenses* for the years noted are as follows:

	(Income) Expense		
	2005	2004	2003
		(Millions)	
Power			
Accrual for litigation contingencies	$ 82.2	$ —	$ —
Gain on sale of Jackson power contract	—	—	(188.0)
Commodity Futures Trading Commission settlement	—	—	20.0
California rate refund and other accrual adjustments	—	—	19.5
Impairment of goodwill	—	—	45.0
Impairment of generation facilities	—	—	44.1
Gas Pipeline			
Write-off of previously capitalized costs on an idled segment of a pipeline	—	9.0	—
Write-off of software development costs due to cancelled implementation	—	—	25.6
Exploration & Production			
Gains on sale of certain natural gas properties	(29.6)	—	(96.7)
Loss provision related to an ownership dispute	—	15.4	—
Midstream Gas & Liquids			
Arbitration award on a Gulf Liquids insurance claim dispute	—	(93.6)	—
Impairment of Gulf Liquids assets	—	2.5	108.7
Gain on sale of the wholesale propane business	—	—	(16.2)
Other			
Gain on sale of land	(9.0)	—	—
Environmental accrual related to the Augusta refinery facility	—	11.8	—
Gain on sale of blending assets	—	—	(9.2)

Power

Accrual for litigation contingencies

This accrual in 2005 includes a $77.2 million charge for agreements reached to substantially resolve exposure related to the inaccurate reporting of natural gas prices and volumes to an industry publication in 2002. See Note 15 for further discussion.

California rate refund and other accrual adjustments

In addition to the $19.5 million charge included in *other (income) expense — net* within *segment costs and expenses* for 2003, a $13.8 million charge is recorded within *costs and operating expenses* in the same period. These two amounts, totaling $33.3 million, are for California rate refund liability and other accrual adjustments and relate to power marketing activities in California during 2000 and 2001 (see Note 15 for further discussion).

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Impairment of goodwill

Because of our exit strategy during 2003 and the market conditions in which this business operated, we evaluated Power's remaining goodwill for impairment. In estimating the fair value of the Power segment, we considered our derivative portfolio which is carried at fair value on the balance sheet and our nonderivative portfolio which is no longer carried at fair value on the balance sheet. Because of the significant negative fair value of certain of our nonderivative contracts, we determined we may be unable to realize the carrying value of this segment; and thus, we recognized a $45 million goodwill impairment during 2003.

Impairment of generation facilities

The 2003 impairment relates to the Hazelton generation facility. Fair value was estimated using future cash flows based on current market information and discounted at a risk adjusted rate.

Midstream Gas & Liquids

Arbitration award on a Gulf Liquids insurance claim dispute

Winterthur International Insurance Company (Winterthur) issued policies to Gulf Liquids providing financial assurance related to construction contracts. After disputes arose regarding obligations under the construction contracts, Winterthur disputed coverage resulting in arbitration between Winterthur and Gulf Liquids. In July 2004, the arbitration panel awarded Gulf Liquids $93.6 million, plus interest of $9.6 million. Following the arbitration decision, Winterthur filed a Petition to Vacate the Final Award in the New York State court and Gulf Liquids filed a Cross-Petition to Confirm the Final Award. Prior to the State court's ruling, Winterthur agreed to the terms of the award and on November 1, 2004, remitted the proceeds to us. As a result, we recognized total income of approximately $103 million related to the arbitration award in fourth quarter 2004.

Impairment of Gulf Liquids assets

During second quarter 2003, our Board of Directors approved a plan to sell the assets of Gulf Liquids. In the third quarter of 2005, we sold substantially all of Gulf Liquids. We recognized impairment charges of $2.5 million and $108.7 million during 2004 and 2003, respectively, to reduce the carrying cost of the long-lived assets to estimated fair value less costs to sell the assets. We estimated fair value based on a probability-weighted analysis of various scenarios including expected sales prices, discounted cash flows and salvage valuations. Prior to fourth quarter 2004, the operations of Gulf Liquids were included in discontinued operations.

Other

Environmental accrual related to the Augusta refinery facility

As a result of information obtained in fourth quarter 2004 related to the Augusta refinery site, we accrued additional amounts for completion of work under a current Administrative Order on Consent and reasonably estimated remediation costs. Accruals may be adjusted as more information from the site investigation becomes available.

Additional Items

Revenues within our Power segment 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.

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

- An adjustment to reduce costs by $12.1 million to correct the carrying value of certain liabilities recorded in prior periods;
- Income from a liability reversal of $14.2 million associated with a favorable ruling involving adjustments to estimated gas purchase costs for operations in prior periods;
- A prior period charge of approximately $32.1 million related to accounting and valuation corrections for certain inventory items;
- An accrual of approximately $5.2 million for contingent refund obligations.

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

- An adjustment to reduce costs by $5.6 million to correct the carrying value of certain liabilities recorded in prior periods;
- A $17.1 million reduction in pension expense for the cumulative impact of a correction of an error attributable to 2003 and 2004 (see Note 7).

General corporate expenses in 2005 includes $13.8 million of expense in our Other segment related to the settlement of certain insurance coverage issues with an insurer that had underwritten portions of the fiduciary insurance applicable to our ERISA litigation settlement and the directors and officers insurance applicable to our pending securities litigation.

Note 5. Provision (Benefit) for Income Taxes

The *provision (benefit) for income taxes* from continuing operations includes:

	2005	2004	2003
		(Millions)	
Current:			
Federal	$ 225.0	$ 11.0	$ (8.8)
State	2.8	(13.7)	(17.6)
Foreign	31.4	11.0	8.8
	259.2	8.3	(17.6)
Deferred:			
Federal	(52.9)	75.1	(17.0)
State	15.6	38.7	44.4
Foreign	(8.0)	9.2	(15.1)
	(45.3)	123.0	12.3
Total provision (benefit)	$ 213.9	$ 131.3	$ (5.3)

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	2005	2004	2003
		(Millions)	
Provision (benefit) at statutory rate	$ 186.0	$ 78.6	$ (22.0)
Increases in taxes resulting from:			
State income taxes (net of federal benefit)	21.5	27.9	.5
Foreign operations — net	6.7	6.1	3.5
Capital losses	—	—	(39.6)
Valuation allowance/expiration charitable contributions	8.4	13.8	—
Non-deductible impairment of goodwill	—	—	15.8
Adjustment of excess deferred taxes	(20.2)	—	—
Non-deductible penalties	17.7	(.9)	9.0
Other — net	(6.2)	5.8	27.5
Provision (benefit) for income taxes	$ 213.9	$ 131.3	$ (5.3)

Utilization of foreign operating loss carryovers reduced the provision for income taxes by $13 million and $19 million in 2005 and 2003, respectively. During 2004, the utilization of foreign tax credits reduced the provision for income taxes by $12 million.

Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles includes $59 million, $51 million, and $9 million of international income in 2005, 2004, and 2003, respectively.

We provide for income taxes using the asset and liability method as required by SFAS No. 109, “Accounting for Income Taxes.” During 2005, as a result of additional analysis of our tax basis and book basis assets and liabilities, we recorded a $20.2 million tax benefit adjustment to reduce the overall deferred income tax liabilities on the Consolidated Balance Sheet.

Significant components of *deferred tax liabilities* and *deferred tax assets* as of December 31, 2005, and 2004, are as follows:

	2005	2004
	(Millions)	
Deferred tax liabilities:		
Property, plant and equipment	$ 2,718.9	$ 2,356.5
Derivatives — net	61.3	99.3
Investments	310.9	442.4
Other	80.1	201.8
Total deferred tax liabilities	3,171.2	3,100.0
Deferred tax assets:		
Minimum tax credits	163.8	151.0
Accrued liabilities	413.8	171.5
Receivables	39.3	44.2
Federal carryovers	286.0	315.3
Foreign carryovers	30.4	54.1
Other	7.1	44.3
Total deferred tax assets	940.4	780.4
Valuation allowance	37.1	61.5
Net deferred tax assets	903.3	718.9
Overall net deferred tax liabilities	$ 2,267.9	$ 2,381.1

The *valuation allowance* at December 31, 2005, and 2004, serves to reduce the recognized tax benefit associated with charitable contribution carryovers and foreign carryovers to an amount that will, more likely than not, be realized.

Undistributed earnings of certain consolidated foreign subsidiaries at December 31, 2005, totaled approximately $142 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 $230 million and $8 million in 2005 and 2004, respectively. Of the $230 million for 2005, $204 million relates to settlements with taxing authorities associated with prior period audits. Cash refunds for income taxes (net of payments) were $88 million in 2003.

At December 31, 2005, federal net operating loss carryovers are $773 million and charitable contribution carryovers are $44 million. We do not expect to utilize $24 million of charitable contribution carryovers prior to expiration in 2006. We expect to utilize the net operating loss carryovers prior to expiration in 2022 through 2025 and the remaining $20 million of charitable contribution carryovers prior to expiration in 2007 and 2008. We also do not expect to be able to utilize $29 million of the $30.4 million available foreign deferred tax assets related to carryovers.

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 record a liability for probable tax contingencies. In association with this liability, we record an estimate of related interest as a component of our current tax provision. The impact of this accrual is included within *other — net* in our reconciliation of the tax provision to the federal statutory rate.

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

Basic and diluted earnings (loss) per common share for the years ended December 31, 2005, 2004 and 2003, are:

	2005	2004	2003
		(Dollars in millions, except per-share amounts; shares in thousands)	
Income (loss) from continuing operations(1)	$ 317.4	$ 93.2	$ (57.5)
Convertible preferred stock dividends (see Note 12)	—	—	29.5
Income (loss) from continuing operations available to common stockholders for basic and diluted earnings per share	$ 317.4	$ 93.2	$ (87.0)
Basic weighted-average shares(2)	570,420	529,188	518,137
Effect of dilutive securities:			
Unvested deferred shares(3)	2,890	2,631	—
Stock options	4,989	3,792	—
Convertible debentures	27,548	—	—
Diluted weighted-average shares	605,847	535,611	518,137
Earnings (loss) per common share from continuing operations:			
Basic	$ .55	$ .18	$ (.17)
Diluted	$ .53	$ .18	$ (.17)

(1) The year ended December 31, 2005, includes $10.2 million of interest expense, net of tax, associated with our convertible debentures (see Note 12). This amount has been added back to *income from continuing operations available to common stockholders* to calculate diluted earnings per common share (see discussion of antidilutive items below).

(2) In February 2005 and October 2004, we issued 10.9 million and 33.1 million, respectively, common shares associated with our FELINE PACS units (see Note 12).

(3) The unvested deferred shares outstanding at December 31, 2005, will vest over the period from January 2006 to January 2010.

Approximately 27.5 million and 16.5 million weighted-average shares related to the assumed conversion of convertible debentures, as well as the related interest, have been excluded from the computation of diluted earnings per common share for the years ended December 31, 2004, and 2003, respectively. Inclusion of these shares would have an antidilutive effect on diluted earnings per common share. If no other components used to calculate diluted earnings per common share change, we estimate the assumed conversion of convertible debentures would have become dilutive and therefore be included in diluted earnings per common share at an *income from continuing operations available to common stockholders* amount of $198.1 million and $192.1 million for the years ended December 31, 2004, and 2003, respectively.

For the year ended December 31, 2003, approximately 3.6 million weighted-average stock options, approximately 6.4 million weighted-average shares related to the assumed conversion of 9.875 percent cumulative convertible preferred stock and approximately 2.5 million weighted-average unvested deferred shares have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive. The preferred stock was redeemed in June 2003.

The table below includes information related to 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.

	2005	2004	2003
Options excluded (millions)	4.7	8.5	15.0
Weighted-average exercise prices of options excluded	$35.22	$28.21	$22.77
Exercise price ranges of options excluded	$22.68 - $42.29	$14.61 - $42.29	$10.39 - $42.52
Fourth quarter weighted-average market price	$22.41	$14.41	$9.76

During January 2006, we issued 20.2 million shares of common stock related to a conversion offer for our convertible debentures (see Note 12). These shares will be a component of basic earnings per common share in future periods.

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 these 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. It also presents a reconciliation of the funded status of these benefit plans to the amounts recorded in the Consolidated Balance Sheet at December 31 of each year indicated. The annual measurement date for our plans is December 31.

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 893.0	$ 775.9	$ 268.4	$ 362.4
Service cost	21.5	24.0	3.3	3.2
Interest cost	47.6	50.5	20.3	18.8
Plan participants' contributions	—	—	4.3	4.3
Curtailment	—	(2.3)	—	—
Settlement benefits paid	(4.0)	(.4)	—	—
Benefits paid	(58.2)	(78.8)	(24.0)	(24.8)
Plan amendments	—	7.8	51.2	(75.5)
Actuarial (gain) loss	(2.5)	116.3	51.9	(20.0)
Benefit obligation at end of year	897.4	893.0	375.4	268.4
Change in plan assets:				
Fair value of plan assets at beginning of year	835.5	706.3	158.9	152.7
Actual return on plan assets	56.4	69.6	9.5	13.2
Employer contributions	57.9	138.8	14.9	13.5
Plan participants' contributions	—	—	4.3	4.3
Benefits paid	(58.2)	(78.8)	(24.0)	(24.8)
Settlement benefits paid	(4.0)	(.4)	—	—
Fair value of plan assets at end of year	887.6	835.5	163.6	158.9
Funded status	(9.8)	(57.5)	(211.8)	(109.5)
Unrecognized net actuarial loss	309.7	295.3	74.4	23.7
Unrecognized prior service cost (credit)	5.1	4.7	1.7	(53.8)
Prepaid (accrued) benefit cost	$ 305.0	$ 242.5	$ (135.7)	$ (139.6)

Amounts recognized in the Consolidated Balance Sheet consist of:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
	(Millions)			
Prepaid benefit cost	$ 312.6	$ 251.0	$ —	$ —
Accrued benefit cost	(16.8)	(17.6)	(135.7)	(139.6)
Regulatory asset	2.3	1.7	—	—
Accumulated other comprehensive income (before tax).	6.9	7.4	—	—
Prepaid (accrued) benefit cost	$ 305.0	$ 242.5	$ (135.7)	$ (139.6)

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The *regulatory asset* shown in the table above is the portion of the additional minimum pension liability recognized by our FERC-regulated gas pipelines. As required by FERC accounting guidelines, our FERC-regulated gas pipelines are required to record the effect of an additional minimum pension liability to a *regulatory asset* instead of *accumulated other comprehensive income.*

The 2005 *actuarial gain* of $2.5 million for our pension plans included in the table of changes in benefit obligation reflects a gain of approximately $68 million for the cumulative impact of a correction of an error determined to have occurred in 2003 and 2004. The error was associated with our third-party actuarial computation of the benefit obligation which resulted in the identification of errors in certain Transco participant data involving annuity contract information utilized for 2003 and 2004. This gain is offset substantially by the impact of changes to the discount rates utilized to determine the benefit obligation. The 2004 *actuarial loss* of $116.3 million for our pension plans included in the table of changes in benefit obligation reflects the impact of changes in various actuarial assumptions used to calculate the benefit obligation including the expected type of benefit payment and discount rates. The 2005 actuarial loss of $51.9 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 the health care cost trend rates, discount rate and estimated cost savings related to the Medicare Prescription Drug Act.

The current accounting rules for pension and other postretirement benefit plans 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 *unrecognized net actuarial loss* presented in the previous table represents the cumulative net deferred losses from these types of differences or changes which have not yet been recognized in the financial statements. A portion of the net unrecognized gains and losses are amortized over the participants' average remaining future years of service, which is approximately 12 years for our pension plans and 14 years for our other postretirement benefit plans.

The accumulated benefit obligation for our pension plans was $831.4 million and $823.4 million at December 31, 2005, and 2004, respectively.

The projected benefit obligation and fair value of plan assets for our pension plans with projected benefit obligation in excess of plan assets were $428.6 million and $359.7 million, respectively, at December 31, 2005, and $381.2 million and $305.3 million, respectively, at December 31, 2004. The accumulated benefit obligation for pension plans with accumulated benefit obligations in excess of plan assets was $16.7 million at December 31, 2005, and $17.6 million at December 31, 2004. There were no assets for these plans at December 31, 2005, and December 31, 2004.

Net Periodic Pension and Other Postretirement Benefit Expense (Income)

Net periodic pension expense (income) and *other postretirement benefit expense (income)* for the years ended December 31, 2005, 2004, and 2003, consists of the following:

	Pension Benefits		
	2005	2004	2003
		(Millions)	
Components of net periodic pension expense (income):			
Service cost	$ 21.5	$ 24.0	$ 25.5
Interest cost	47.6	50.5	52.7
Expected return on plan assets	(71.1)	(64.9)	(54.2)
Amortization of prior service credit	(.4)	(1.5)	(2.5)
Recognized net actuarial (gain) loss	(4.9)	9.4	13.7
Regulatory asset amortization	.6	2.0	3.9
Settlement/curtailment expense	2.7	.1	.6
Net periodic pension expense (income)	$ (4.0)	$ 19.6	$ 39.7

	Other Postretirement Benefits		
	2005	2004	2003
		(Millions)	
Components of net periodic other postretirement benefit expense (income):			
Service cost	$ 3.3	$ 3.2	$ 6.2
Interest cost	20.3	18.8	24.1
Expected return on plan assets	(11.5)	(12.4)	(13.0)
Amortization of transition obligation	—	2.7	2.7
Amortization of prior service cost (credit)	(4.3)	.6	.6
Recognized net actuarial loss	3.2	—	—
Regulatory asset amortization	6.8	6.7	8.6
Settlement/curtailment income	—	—	(41.9)
Net periodic other postretirement benefit expense (income)	$ 17.8	$ 19.6	$ (12.7)

Net periodic pension expense (income) for 2005 includes a $17.1 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 our third-party actuarial computation of annual *net periodic pension expense* 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 $16.1 million within *recognized net actuarial (gain) loss* and $1 million within *regulatory asset amortization.*

The $41.9 million *settlement/curtailment income* component of *net periodic other postretirement benefit expense (income)* in 2003 is included in *income (loss) from discontinued operations* in the Consolidated Statement of Operations due to the settlement/curtailment directly resulting from the sale of the operations included within discontinued operations.

The amount of other postretirement benefit costs deferred as a net regulatory asset at December 31, 2005, and 2004, is $13 million and $18 million, respectively, and is expected to be recovered through rates over approximately six years.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Key Assumptions

The weighted-average assumptions utilized to determine benefit obligations as of December 31, 2005, and 2004, are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	5.65%	5.86%	5.60%	5.75%
Rate of compensation increase	5	5	N/A	N/A

The weighted-average assumptions utilized to determine *net pension and other postretirement benefit expense* for the years ended December 31, 2005, 2004, and 2003, are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
Discount rate	5.86%	6.25%	7%	5.63%	6.25%	7%
Expected long-term rate of return on plan assets	8.5	8.5	8.5	7.45	8.5	7
Rate of compensation increase	5	5	5	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. With the assistance of our third-party actuary, the plans were analyzed and discount rates based on a yield curve comprised of high-quality corporate bonds published by a large securities firm were matched to a highly correlated published index of high-quality corporate bonds. Based on an analysis performed between each of the plans' yield curve discount rates and the index, a formula was developed to determine the December 31, 2005, discount rates based upon the year-end published index.

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 the capital market projections provided by our independent investment consultant 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 to our third-party actuary's 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 2006 is 10 percent, and systematically decreases to 5 percent by 2014.

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	$ 4.8	$ (3.8)
Effect on postretirement benefit obligation	72.7	(57.8)

Medicare Prescription Drug Act

In December 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. The Act introduces a prescription drug benefit under Medicare (Medicare Part D) beginning in 2006 as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our health care plans for retirees include prescription drug coverage. In accordance with FSP No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," the provisions of the Act were not reflected in any measures of benefit obligations or other postretirement benefit expense in the financial statements or accompanying notes until further guidance was effective. In May 2004, the FASB issued FSP No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." Although final guidance had not been issued, we believed the prescription drug benefits included in our health care plans for retirees, prior to the amendment of the plans discussed below, were actuarially equivalent to Medicare Part D. In accordance with FSP No. FAS 106-2, we reflected the effect of the subsidy on the measurement of *net periodic other postretirement benefit expense (income)* in 2004. *Net periodic other postretirement benefit expense (income)* for the year ended December 31, 2004, reflects a reduction of $3.4 million, including a decrease in *service cost* of $.4 million and decrease in *interest cost* of $2.7 million. The reduction in the benefit obligation was approximately $43 million as of January 1, 2004, and is included as a component of the *actuarial (gain) loss* in the table of changes in benefit obligation. We amended our health care plans for retirees in the fourth quarter of 2004 to coordinate and pay secondary to any part of Medicare, including prescription drug benefits covered by Medicare Part D. This amendment further decreased the benefit obligation by $75.5 million and is reflected as a *plan amendment* in the table of changes in benefit obligation for 2004. As a result of the amendment, our plans were no longer actuarially equivalent to Medicare Part D. Beginning in 2005, the net reduction to the obligation is being amortized over approximately seven years which is the participants' average remaining years of service to full eligibility for benefits. It is reflected in the *amortization of prior service credit* in the table of components of *net periodic other postretirement benefit expense (income*) for 2005.

Due to anticipated difficulties to administer our plans as previously amended to coordinate and pay secondary to Medicare Part D in 2006, we amended our plans in June 2005 to generally provide primary prescription drug coverage and apply for the federal subsidy in 2006. As a result of the amendment, generally our plans are designed to be actuarially equivalent to the standard coverage under Medicare Part D. The amendment increased our benefit obligation by $51.2 million at June 30, 2005, and is reflected as a *plan amendment* in the table of changes in benefit obligation for 2005. Beginning in the third quarter of 2005, the increase to the obligation is being amortized over the participants' average remaining years of service to full eligibility for benefits, which is approximately seven years. *Net periodic other postretirement benefit expense* for 2005, reflects an increase of $7.1 million, including an increase in *recognized net actuarial loss* of $.3 million, an increase in *service cost* of $.3 million, an increase in *interest cost* of $2.6 million, and an increase in *amortization of prior service credit* of $3.9 million, resulting from the plan amendment. We are continuing to evaluate coordination with Medicare Part D as a strategy to decrease our benefit obligation in the future and will closely monitor the development of systems and capabilities of third-party administrators to coordinate prescription drug benefits with the Centers for Medicare & Medicaid Services.

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, 2005, and 2004 and target asset allocation at December 31, 2005, by asset category.

	Pension Benefits			Other Postretirement Benefits		
	2005	2004	Target	2005	2004	Target
Equity securities	81%	82%	84%	78%	77%	80%
Debt securities	13	14	16	13	14	20
Other	6	4	—	9	9	—
	100%	100%	100%	100%	100%	100%

Included in equity securities are investments in commingled funds that invest entirely in equity securities and comprise 37 percent of the pension plans weighted-average assets at December 31, 2005, and 2004 and 26 percent and 24 percent of the other postretirement benefit plans' weighted-average assets at December 31, 2005, and 2004, respectively. Other assets are comprised primarily of cash and cash equivalents for the pension plans and cash and cash equivalents, and insurance contract assets for the other postretirement benefit plans.

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 2005, 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.

Periodically, an asset and liability study is performed to determine the optimal asset mix to meet future benefit obligations. The most recent pension asset and liability study was performed in 2001.

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)	
2006	$ 41.3	$ 22.0	$ 2.1
2007	39.2	23.8	2.4
2008	40.2	25.4	2.6
2009	43.8	26.9	2.8
2010	39.4	28.2	3.1
2011-2015	200.7	152.4	19.0

We expect to contribute approximately $20 million to our pension plans and approximately $16 million to our other postretirement benefit plans in 2006.

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 related to continuing operations of $17 million were recognized for these plans in 2005 and 2004 and $18 million was recognized for these plans in 2003. 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 compensation cost related to the ESOP of $.7 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 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, 2005, and 2004, are as follows:

	2005	2004
	(Millions)	
Natural gas liquids	$ 100.0	$ 63.2
Natural gas in underground storage	90.4	133.1
Materials, supplies and other	82.2	64.8
	$ 272.6	$ 261.1

Inventories determined using the LIFO cost method were approximately 8 percent and 6 percent of *inventories* at December 31, 2005, and 2004, respectively. The remaining *inventories* were primarily determined using the average-cost method.

If *inventories* valued using the LIFO cost method at December 31, 2005 and 2004, were valued at current replacement cost, the amounts would increase by $59 million and $25 million, respectively.

Natural gas in underground storage reflects a $32.1 million charge recorded in 2005 for prior period accounting and valuation corrections.

Note 9. Property, Plant and Equipment

Property, plant and equipment-net at December 31, 2005, and 2004, is as follows:

	2005	2004
	(Millions)	
Cost:		
Power	$ 154.9	$ 188.2
Gas Pipeline	8,371.1	8,140.3
Exploration & Production(1)	4,458.9	3,690.6
Midstream Gas & Liquids(1)	4,351.4	4,189.9
Other	235.5	243.8
	17,571.8	16,452.8
Accumulated depreciation, depletion and amortization	(5,162.6)	(4,566.0)
	$ 12,409.2	$ 11,886.8

(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 $739 million in 2005, $667.4 million in 2004, and $655.6 million in 2003.

Property, plant and equipment-net includes approximately $374 million at December 31, 2005, and $218 million at December 31, 2004, of construction in progress which is not yet subject to depreciation. In addition, property of Exploration & Production includes approximately $443 million at December 31, 2005, and $561 million at December 31, 2004, of capitalized costs related to properties with unproven reserves not yet subject to depletion.

Property, plant and equipment-net includes approximately $1.2 billion at December 31, 2005, and 2004, 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

In March 2005, the FASB issued FIN 47, “Accounting for Conditional Asset Retirement Obligations — an interpretation of FASB Statement No. 143.” The Interpretation clarifies that the term “conditional asset retirement” as used in SFAS No. 143, “Accounting for Asset Retirement Obligations,” refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

We adopted the Interpretation on December 31, 2005. In accordance with the Interpretation, we estimated future retirement obligations for certain assets previously considered to have an indeterminate life.

As a result, we recorded an increase in *other liabilities and deferred income* of $29.4 million, an increase in *property, plant and equipment — net* of $12.2 million, and a *cumulative effect of change in accounting principle of* $1.7 million (net of $1.0 million of taxes). We also recorded a $14.5 million regulatory asset in *other assets and deferred charges* for retirement costs expected to be recovered through regulated rates. Had we implemented the Interpretation at the beginning of 2003, the financial statement impact at December 31, 2004 would not be substantially different than the impact at December 31, 2005.

We adopted SFAS No. 143 on January 1, 2003. As a result, we recorded an increase in *other liabilities and deferred* income of $33.4 million, an increase in *property, plant and equipment — net* of $24.8 million, and a *cumulative effect of a change in accounting principle* credit of $1.2 million (net of $0.1 million of taxes). We also recorded a $9.7 million regulatory asset in *other assets and deferred charges* for retirement costs expected to be recovered through regulated rates.

The asset retirement obligation at December 31, 2005 and 2004 is $93 million and $55 million, respectively. The increase in the obligation in 2005 is primarily due to implementation of FIN 47, accretion, and revisions to liability estimates.

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 subsidiaries' cash accounts reflect credit balances to the extent checks written have not been presented for payment. *Accounts payable* includes approximately $69 million of these credit balances at December 31, 2005, and $6 million at December 31, 2004.

On May 26, 2004, we were released from certain historical indemnities, primarily related to environmental remediation, for an agreement to pay $117.5 million. We had previously deferred $113 million of a gain on sale related to these indemnities. At the date of sale, the deferred revenue and identified obligations related to the indemnities totaled $102 million. The carrying value of this obligation is $51.3 million at December 31, 2005, and $74.8 million at December 31, 2004. We will pay the remaining balance in two installments of $20 million on July 1, 2006, and $35 million on July 1, 2007.

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 $47 million at December 31, 2005, and $49 million at December 31, 2004. Our exposure declines systematically throughout the remaining term of WilTel's obligations.

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Accrued liabilities at December 31, 2005, and 2004, are as follows:

	2005	2004
	(Millions)	
Interest	$ 245.0	$ 238.2
Taxes other than income taxes	141.4	109.1
Employee costs	147.2	151.3
Accrual for Power litigation contingencies	52.2*	—
Guarantees and payment obligations related to WilTel	42.7	44.4
Net lease obligation	30.3	35.6
Structured indemnity settlement	19.4	26.7
Income taxes	58.2	4.0
Other	385.5	364.7
	$ 1,121.9	$ 974.0

* Represents the current portion. An additional $30 million is included in *Other liabilities and deferred income.*

Note 11. Debt, Leases and Banking Arrangements

Long-Term Debt

Long-term debt at December 31, 2005 and 2004, is:

	Weighted-Average Interest Rate (1)	December 31, 2005	December 31, 2004
		(Millions)	
Secured(2)			
6.62%-9.45%, payable through 2016	8.0%	$ 195.7	$ 219.7
Adjustable rate, payable through 2016	6.4%	572.2	587.3
Capital lease obligations	9.3%	2.8	—
Unsecured			
5.5%-10.25%, payable through 2033	7.6%	6,867.3	7,079.7
Adjustable rate, due 2008	5.4%	75.0	75.0
Other, payable through 2007	6.0%	.1	.3
Total long-term debt, including current portion		7,713.1	7,962.0
Long-term debt due within one year		(122.6)	(250.1)
Long-term debt		$ 7,590.5	$ 7,711.9

(1) At December 31, 2005.

(2) Includes $487.6 million and $492.5 million at December 31, 2005 and 2004, respectively, secured by substantially all of the assets of Williams Production RMT Company. The net book value of these assets significantly exceeds the outstanding debt. Also includes $280.3 million and $314.5 million at December 31, 2005 and 2004, respectively, collateralized by certain fixed assets of two of our Venezuelan subsidiaries with a net book value of $408.7 million and $444.6 million at December 31, 2005 and 2004, respectively.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Revolving credit and letter of credit facilities

In January 2005, we replaced two unsecured bank revolving credit facilities totaling $500 million with two new facilities for the same amount, which have the same terms but almost all of the restrictive covenants and events of default were removed or made less restrictive. These facilities provide for both borrowings and issuing letters of credit but are expected to be used primarily for issuing letters of credit. In connection with the replacement, we paid $19.1 million in fees that are being amortized over the life of the new facilities. We are required to pay to the bank fixed fees at a weighted-average rate of 3.64 percent 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. We were able to obtain the unsecured credit facilities because 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:

- A fixed facility fee at a weighted-average rate of 3.19 percent to the investors;
- Interest on borrowings under the $400 million facility equal to a fixed rate of 3.57 percent;
- Interest on borrowings under the $100 million facility at a fluctuating LIBOR interest rate.

At December 31, 2005, letters of credit totaling $465 million have been issued under these facilities and no revolving credit loans are outstanding.

During May 2005, we amended and restated our $1.275 billion secured revolving credit facility, which is available for borrowings and letters of credit, resulting in certain changes, including the following:

- Added Williams Partners L.P. as a borrower for up to $75 million;
- Provided our guarantee for the obligations of Williams Partners L.P. under this agreement;
- Released certain Midstream assets held as collateral and replaced them with the common stock of Transco;
- Reduced commitment fees and margins.

The facility is guaranteed by Williams Gas Pipeline Company, LLC. 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 facilitating bank'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 .325 percent annually) based on the unused portion of the facility. The applicable margins and commitment fee are based on the relevant borrower's senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include the following:

- Ratio of debt to capitalization no greater than 70 percent for the period of December 31, 2004, through December 31, 2005, and 65 percent for the remaining term of the agreement. At December 31, 2005, we are in compliance with this covenant as our ratio of debt to capitalization, as calculated under this covenant, is approximately 57 percent.
- Ratio of debt to capitalization, as calculated under this covenant, no greater than 55 percent for Northwest Pipeline and Transco.

- Ratio of EBITDA to interest, on a rolling four quarter basis, no less than (i) 1.5 for the period ending March 31, 2005, (ii) 2.0 for any period after March 31, 2005 through December 31, 2005, and (iii) 2.5 for the remaining term of the agreement. Through December 31, 2005, we are in compliance with this covenant as we exceed the compliance level by approximately 62 percent.

At December 31, 2005, letters of credit totaling $378 million have been issued under this facility and no revolving credit loans are outstanding.

In September 2005, we entered into two unsecured bank revolving credit facilities totaling $700 million that are similar in structure to our $500 million credit facilities. These facilities provide for both borrowings and issuing letters of credit, but are expected to be used primarily for issuing letters of credit. We are required to pay fixed facility fees at a weighted-average rate of 2.29 percent on the total committed amount of the facilities. In addition, we will pay interest on any borrowings at a fluctuating rate comprised of either a base rate or LIBOR. Similar to our $500 million facilities described above, we were able to obtain these unsecured facilities because the funding bank syndicated its associated credit risk into the institutional investor market through a private offering. 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:

- A fixed facility fee as described above;
- Interest on borrowings under the $500 million facility at a fixed rate of 4.35 percent;
- Interest on borrowings under the $200 million facility at a floating LIBOR interest rate.

At December 31, 2005, letters of credit totaling $671 million have been issued under these facilities and no revolving credit loans are outstanding.

Retirements

During January 2005, we retired $200 million of 6.125 percent notes issued January 15, 1998, by Transco, which matured January 15, 2005.

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)
2006	$ 119.0
2007	396.3
2008	715.6
2009	53.1
2010	217.3

Cash payments for interest (net of amounts capitalized) were as follows: 2005 — $625 million; 2004 — $849 million; and 2003 — $1.3 billion.

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 $220.2 million of the debentures (see Note 12).

Leases-Lessee

Future minimum annual rentals under noncancelable operating leases as of December 31, 2005, are payable as follows:

	(Millions)
2006	$ 231.8
2007	229.1
2008	225.8
2009	201.4
2010	179.2
Thereafter	1,238.6
Total	$ 2,305.9

The above amounts include obligations of approximately $2 billion related to a tolling agreement at Power that is accounted for as an operating lease as a result of changes to the contract terms in 2004 after implementation of EITF 01-8 (see Note 1). Under the tolling agreement, Power has the exclusive right to capacity and fuel conversion services as well as ancillary services associated with electric generation facilities that are currently in operation in southern California. Current annual rentals under this tolling agreement are approximately $162 million with approximately 12 years remaining on the agreement as of December 31, 2005. These rentals are offset through year 2010 with income from sales and other transactions made possible by the tolling agreement.

Total rent expense was $226 million in 2005, $206 million in 2004 and $110 million in 2003. Rent expense at Power, primarily related to the tolling agreement, was $161 million (including ($1) million of contingent rentals) in 2005 and $136 million (including $9 million of contingent rentals) in 2004. Contingent rentals are primarily based on utilization of the leased property or changes in the capacity and availability of the power generating facility. Income from sales and other transactions made possible by the tolling agreement was approximately $172 million (including $7 million of contingent rental income) in 2005 and $129 million (including $6 million of contingent rental income) in 2004.

Note 12. Stockholders' Equity

On June 10, 2003, we redeemed all of the outstanding 9.875 percent cumulative-convertible preferred shares for approximately $289 million, plus $5.3 million for accrued dividends. The $13.8 million of payments in excess of carrying value of the shares was also recorded as a dividend. These shares were repurchased with proceeds from a private placement of $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 the 5.5 percent junior subordinated convertible debentures into our common stock. In January 2006, we converted approximately $220.2 million of the debentures in exchange for 20.2 million shares of common stock, a $25.8 million cash premium, and $1.5 million of accrued interest.

In January 2002, we issued $1.1 billion of 6.5 percent notes payable in 2007 that were subject to remarketing in 2004. Each note was bundled with an equity forward contract (together, the FELINE PACS units) and sold in a public offering for $25 per unit. The equity forward contract required the holder of each note to purchase one share of our common stock for $25 three years from issuance of the contract. In the fourth quarter of 2004, we exchanged approximately 33.1 million of the 44 million issued and outstanding FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit. On February 16, 2005, the settlement date of the equity forward contracts, the holders of the remaining 10.9 million equity forward contracts purchased one share of our common stock for $25, resulting in cash proceeds of approximately $273 million and an increase in *capital in excess of par value* of approximately $262 million.

We maintain a Stockholder Rights Plan, as amended and restated on September 21, 2004, 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 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

The Williams Companies, Inc. 2002 Incentive Plan (Plan) was approved by stockholders on May 16, 2002, and amended and restated on May 15, 2003, and January 23, 2004. The Plan provides for common-stock-based awards to both employees and nonmanagement directors. Upon approval by the stockholders, all prior stock plans were terminated resulting in no further grants being made from those plans. However, awards outstanding in those prior plans remain in those plans with their respective terms and provisions.

The Plan permits the granting of various types of awards including, but not limited to, stock options, restricted stock and deferred stock. Awards may be granted for no consideration other than prior and future services or based on certain financial performance targets being achieved. At December 31, 2005, 45 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 21.6 million shares were available for future grants. At December 31, 2004, 49.7 million shares of our common stock were reserved for issuance, of which 25.2 million were available.

Loans

Several of our prior stock plans allowed us to loan money to participants to exercise stock options using stock certificates as collateral. Effective November 14, 2001, we no longer issue loans under the stock option loan programs. Loan holders were offered a one-time opportunity in January 2002 to refinance outstanding loans at a market rate of interest commensurate with the borrower’s credit standing. At December 31, 2005, $4.6 million of the notes remain outstanding. However, $4.4 million of the outstanding notes were paid by the end of February 2006. Loans outstanding at December 31, 2004, totaled $22 million (net of a $7 million allowance).

Deferred Shares

Deferred shares are valued at the date of award. Deferred share expense is recognized in the performance year or over the vesting period, depending on the terms of the awards. Expense related to forfeited shares is recognized in the year of the forfeiture.

	2005	2004	2003
		(Millions, except per-share amounts)	
Deferred shares granted	1.4	1.8	.2
Deferred shares issued	.6	.9	1.3
Weighted average fair value of deferred shares granted, per share	$ 19.35	$ 10.54	$ 4.68
Deferred share expense	$ 14	$ 14	$ 30

Options

The purchase price per share for stock options 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 grant and generally expire ten years after grant.

On May 15, 2003, our shareholders approved a stock option exchange program. Under this program, eligible employees were given a one-time opportunity to exchange certain outstanding options for a proportionately lesser number of options at an exercise price to be determined at the grant date of the new options. Surrendered options were cancelled June 26, 2003, and replacement options were granted on December 29, 2003. We did not recognize any expense pursuant to the stock option exchange. However, for purposes of pro forma disclosures, we recognized additional expense related to these new options. The remaining pro forma expense on the cancelled options was amortized through year-end 2004.

The following summary reflects stock option activity for our common stock and related information for 2005, 2004, and 2003:

	2005		2004		2003	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
	(Millions)		(Millions)		(Millions)	
Outstanding — beginning of year	22.0	$ 15.36	25.7	$ 14.63	38.8	$ 19.85
Granted	3.4	19.28	4.5	9.96	4.1*	9.76
Exercised	(4.1)	9.60	(5.5)	3.93	(.2)	5.86
Canceled	(.9)	28.38	(2.7)	22.35	(17.0)**	25.60
Outstanding — end of year	20.4	$ 16.63	22.0	$ 15.36	25.7	$ 14.63
Exercisable — end of year	14.3	$ 17.40	17.1	$ 16.87	12.3	$ 24.23

* Includes 3.9 million shares that were granted December 29, 2003, under the stock option exchange program.

** Includes 10.4 million shares that were cancelled on June 26, 2003, under the stock option exchange program.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following summary provides information about options for our common stock that are outstanding and exercisable at December 31, 2005:

	Stock Options Outstanding			Stock Options Exercisable	
Range of Exercise Prices	**Options**	**Weighted-Average Exercise Price**	**Weighted-Average Remaining Contractual Life**	**Options**	**Weighted-Average Exercise Price**
	(Millions)			(Millions)	
$2.12 to $10.00	10.3	$ 7.23	6.6 years	7.4	$ 6.26
$10.39 to $16.64	1.6	15.47	3.6 years	1.6	15.53
$16.91 to $31.58	4.9	21.35	6.7 years	1.7	25.31
$32.88 to $45.33	3.6	37.66	2.3 years	3.6	37.66
Total	20.4	$ 16.63	5.6 years	14.3	$ 17.40

The estimated fair value at date of grant of options for our common stock granted in 2005, 2004, and 2003, using the Black-Scholes option pricing model, is as follows:

	2005	2004	2003*
Weighted-average grant date fair value of options for our common stock granted during the year	$ 6.70	$ 4.54	$ 2.95
Assumptions:			
Dividend yield	1.6%	0.4%	1%
Volatility	33.3%	50%	50%
Risk-free interest rate	4.1%	3.3%	3.1%
Expected life (years)	6.5	5.0	5.0

* The 2003 weighted average fair value and assumptions do not reflect options that were granted December 29, 2003, as part of the stock option exchange program. The fair value of these options is $1.58, which is the difference in the fair value of the new options granted and the fair value of the exchanged options. The assumptions used in the fair value calculation of the new options granted were: (1) dividend yield of 0.4 percent; (2) volatility of 50 percent; (3) weighted average expected remaining life of 3.4 years; and (4) weighted average risk free interest rate of 1.99 percent.

Pro forma net income (loss) and earnings per share, assuming we had applied the fair-value method of SFAS 123, “Accounting for Stock-Based Compensation,” in measuring compensation cost beginning with 1997 employee stock-based awards, is disclosed under *employee stock-based awards* in Note 1.

Note 14. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk

Financial Instruments

Fair-value methods

We used the following methods and assumptions in estimating our fair-value disclosures for financial instruments:

Cash and cash equivalents and restricted cash: The carrying amounts of cash equivalents reported in the balance sheet approximate fair value due to the short-term maturity of these instruments.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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* consists primarily of auction rate securities.

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 both December 31, 2005 and 2004, approximately 89 percent of our long-term debt was publicly traded. We use the expertise of outside investment banking firms to assist with the estimate of the fair value of our long-term debt.

Energy derivatives: Energy derivatives include:

- Futures contracts;
- Forward purchase and sale 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. Most of these transactions are executed in exchange-traded or over-the-counter markets for which quoted prices in active periods exist. For contracts with lives exceeding the time period for which quoted prices are available, we determined fair value by estimating commodity prices during the illiquid periods. We estimated commodity prices during illiquid periods by incorporating information obtained from commodity prices in actively quoted markets, prices reflected in current transactions and market fundamental analysis.

Carrying amounts and fair values of our financial instruments

Asset (Liability)	2005 Carrying Amount	2005 Fair Value	2004 Carrying Amount	2004 Fair Value
	(Millions)			
Cash and cash equivalents	$ 1,597.2	$ 1,597.2	$ 930.0	$ 930.0
Restricted cash (current and noncurrent)	129.4	129.4	112.7	112.7
Other securities	122.9	122.9	—	—
Notes and other noncurrent receivables	26.6	26.6	80.0	80.5
Cost based investments (see Note 3)	56.7	(a)	69.7	(a)
Long-term debt, including current portion (see Note 11)(b)	(7,710.3)	(8,599.4)	(7,962.0)	(8,857.2)
Structured indemnity settlement obligation (see Note 10)	(51.3)	(51.3)	(74.8)	(74.8)
Margin deposits	349.2	349.2	131.7	131.7
Customer margin deposits payable	(320.7)	(320.7)	(17.7)	(17.7)
Guarantees	43.3	43.3	45.0	45.0
Energy derivatives:				
Energy commodity cash flow hedges	(5.5)	(5.5)	(328.8)	(328.8)
Other energy derivatives	106.9	106.9	718.7	718.7
Other derivatives	.9	.9	1.4	1.4

(a) These investments are primarily in nonpublicly traded companies for which it is not practicable to estimate fair value.

(b) Excludes capital leases.

Energy Derivatives

Our energy derivative contracts include the following:

Futures contracts: Futures contracts are commitments to either purchase or sell a commodity at a future date for a specified price and are generally settled in cash, but may be settled through delivery of the underlying commodity. Exchange-traded or over-the-counter markets providing quoted prices in active periods are available. Where quoted prices are not available, other market indicators exist for the futures contracts we enter into. The fair value of these contracts is based on quoted prices.

Swap agreements and forward purchase and sale contracts: Swap agreements require us to make payments to (or receive payments from) counterparties based upon the differential between a fixed and variable price or variable prices of energy commodities for different locations. Forward contracts, which involve physical delivery of energy commodities, contain both fixed and variable pricing terms. Swap agreements and 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.

Options: 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. 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 attributable to commodity price risk associated with forecasted purchases and sales of natural gas and electricity. Certain of these derivatives have been designated as cash flow hedges.

Our Power segment sells electricity produced by our electric generation facilities, obtained contractually through tolling agreements or obtained through marketplace transactions at different locations throughout the United States. We also buy electricity and capacity to serve our full requirements agreements in the Southeast. To reduce exposure to a decrease in revenues and increase in costs from fluctuations in electricity prices, we enter into fixed-price forward physical sales and purchase contracts to fix the price of forecasted electricity sales and purchases, respectively.

Our electric generation facilities and tolling agreements require natural gas for the production of electricity. To reduce the exposure to increasing costs of natural gas due to changes in market prices, we enter into natural gas futures contracts, swap agreements and fixed-price forward physical purchases to fix the prices of anticipated purchases of natural gas.

Power's cash flow hedges are expected to be highly effective in achieving 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 creditworthiness of counterparties and the hedging derivative contract having an initial fair value upon designation.

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 hedge price risk by entering into natural gas futures contracts, swap agreements, and financial option contracts to fix the price of forecasted sales and purchases of natural gas. We also enter into basis swap agreements as part of our overall natural gas price risk management program to reduce the locational price risk associated with our producing basins. Exploration & Production's cash flow hedges are expected to be highly effective in achieving 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 during which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur either by the end of the originally specified time period or within an additional two-month period. Approximately $2 million and $13 million of net gains from hedge ineffectiveness is included in revenues in the Consolidated Statement of Operations during 2005 and 2004, respectively. For 2005 and 2004, there were no derivative gains or losses excluded from the assessment of hedge effectiveness. As of December 31, 2005, we had hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to 10 years. Based on recorded values at December 31, 2005, approximately $280 million of net losses (net of income tax benefits of $173 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, 2005. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized in 2006 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.

Power elected hedge accounting for certain of its nontrading derivatives in the fourth quarter of 2004 after our Board decided in September 2004 to retain Power and cease efforts to exit that business. Before this election, net changes in the fair value of these derivatives were recognized as revenues in the Consolidated Statement of Operations.

Other energy derivatives

Our Power segment has 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 Operations. 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 Power's future cash flows on an economic basis. In addition, our Exploration & Production segment enters into natural gas basis swap agreements that are not designated in a hedging relationship under SFAS No. 133.

We also hold significant nonderivative energy-related contracts in our Power portfolios. These have not been included in the financial instruments table above because they are not derivatives as defined by SFAS No. 133. See Note 1 regarding *energy commodity risk management and trading activities* for further discussion of the nonderivative energy-related contracts.

Guarantees

In addition to the guarantees and payment obligations discussed elsewhere in these footnotes (see Notes 3, 10, 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, Power, 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 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.

A foreign bank is a defendant in litigation related to a loan they provided to us. We have repaid the loan and indemnified the bank for legal fees and potential losses that may result from this litigation. We are unable to determine the maximum amount of future payments that we could be required to pay as it is dependent upon the ultimate resolution of the claim. However, we believe the probability is remote that a judgment will be made against the bank that we will have to pay. The carrying value of this guarantee is $0.1 million at December 31, 2005.

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.

Former managing directors of Gulf Liquids are involved in litigation related to the construction of the gas processing plants. Gulf Liquids has indemnity obligations to the former directors for legal fees and potential losses that may result from this litigation. We are unable to determine the maximum amount of future payments that we could be required to pay as it is dependent upon the ultimate resolution of the litigation. However, we believe the probability is remote that a judgment will be entered against the former directors that we will have to pay. Thus, no amounts have been accrued for this contingent obligation. These legal fees and any judgment should be recoverable under a directors and officers insurance policy.

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, net of allowances, by product or service at December 31, 2005 and 2004:

	2005	2004
	(Millions)	
Receivables by product or service:		
Sale or transportation of natural gas and related products	$ 1,142.6	$ 859.0
Sales of power and related services	394.5	441.9
Interest	32.4	31.4
Insurance	23.2	14.6
Other	21.1	75.9
Total	$ 1,613.8	$ 1,422.8

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. Customers for power include the California Independent System Operator (ISO), the California Department of Water Resources, and other power marketers and utilities located throughout the majority of the United States. Other receivables in 2004 included a $54.1 million receivable from WilTel. We sold this receivable in January 2005, for $54.6 million. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

As of December 31, 2005, Power had approximately $33 million of certain power receivables net of related allowances from the ISO and the California Power Exchange (compared to $61 million at December 31, 2004). We believe that we have appropriately reflected the collection and credit risk associated with receivables and derivative assets in our Consolidated Balance Sheet and Statement of Operations at December 31, 2005.

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. Risk of loss can result from credit considerations and the regulatory environment of the counterparty. 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.

The concentration of counterparties within the energy and energy trading industry impacts our overall exposure to credit risk in that these counterparties are similarly influenced by changes in the economy and regulatory issues. Additional collateral support could include the following:

- Letters of credit;
- Payment under margin agreements;
- Guarantees of payment by credit worthy parties;

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- Transfers of ownership interests in natural gas reserves or power generation assets.

We also enter into netting agreements to mitigate counterparty performance and credit risk.

The gross credit exposure from our derivative contracts as of December 31, 2005 is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 542.2	$ 572.2
Energy marketers and traders	3,930.1	7,568.6
Financial institutions	1,851.1	1,851.1
Other	.4	1.7
	$ 6,323.8	9,993.6
Credit reserves		(37.0)
Gross credit exposure from derivatives		$ 9,956.6

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of December 31, 2005 is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 129.3	$ 142.1
Energy marketers and traders	401.1	976.7
Financial institutions	36.1	36.1
Other	.5	1.4
	$ 567.0	1,156.3
Credit reserves		(37.0)
Net credit exposure from derivatives		$ 1,119.3

(a) We determine investment grade primarily using publicly available credit ratings. We included 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 2005, 2004 and 2003, 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 of rulings in certain of these proceedings, a portion of the revenues of these subsidiaries has been collected subject to refund. The natural gas pipeline subsidiaries have accrued approximately $4 million for potential refund as of December 31, 2005.

Issues Resulting From California Energy Crisis

Subsidiaries of our Power segment are 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 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. Certain issues, however, 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. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling approximately $27 million at December 31, 2005. Collection of the interest 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 proceeding, including the refund period, are now pending before the Ninth Circuit Court of Appeals. As part of the State Settlement, an additional $60 million, previously accrued, remains to be paid to the California Attorney General (or his designee) over the next five years, with the final payment of $15 million due on January 1, 2010.

Reporting of Natural Gas-Related Information to Trade Publications

We disclosed on October 25, 2002, that certain of our natural gas traders had reported inaccurate information to a trade publication that published gas price indices. In 2002, we received a subpoena from a federal grand jury in northern California seeking documents related to our involvement in California markets, including our reporting to trade publications for both gas and power transactions. We have completed our response to the subpoena. Two former traders with Power have pled guilty to manipulation of gas prices through misreporting to an industry trade periodical. On February 21, 2006, we entered into a deferred prosecution agreement with the Department of Justice (DOJ) that is intended to resolve this matter. Pursuant to the agreement, we will pay $50 million. Absent a breach, the agreement will expire in 15 months and no further action will be taken by the DOJ.

Civil suits based on allegations of manipulating the gas indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in:

- Federal court in New York based on an allegation of manipulation of the NYMEX gas market. We have reached a settlement of this matter for $9.15 million. The settlement agreement has been filed with the court and is subject to court approval.
- Class action litigation in federal court in Nevada alleging that we manipulated gas prices for direct purchasers of gas in California. We have reached settlement of this matter for $2.4 million. Legal documents will be filed with the court and the settlement is subject to court approval.
- Class action litigation in state court in California alleging that we manipulated prices for indirect purchasers of gas in California. We have reached settlement of this matter for $15.6 million. Legal documents will be filed with the court and the settlement is subject to court approval.

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- State court in California on behalf of certain individual gas users.
- Class action litigation in state court in Kansas and Tennessee brought on behalf of indirect purchasers of gas in those states.

It is reasonably possible that additional amounts may be necessary to resolve the remaining outstanding litigation in this area.

Mobile Bay Expansion

In December 2002, an administrative law judge at the FERC issued an initial decision in Transco's 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. Power 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, Power could have been subject to surcharges of approximately $77.1 million, excluding interest, through December 31, 2005, in addition to increased costs going forward. Certain parties have filed appeals in federal court seeking to have the FERC's ruling on the rolled-in rates overturned.

Enron Bankruptcy

We have outstanding claims against Enron Corp. and various of its subsidiaries (collectively "Enron") related to its bankruptcy filed in December 2001. In 2002, we sold $100 million of our claims against Enron to a third party for $24.5 million. In 2003, Enron filed objections to these claims. We have resolved Enron's objections, subject to court approval. Under the sales agreement, the purchaser of the claims may demand repayment of the purchase price for the reduced portions of the claims. We anticipate negotiating with the purchaser regarding potential payment obligations.

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 programs 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, 2005, Transco had accrued liabilities of $14 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, Transco has estimated its 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-1980's, 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. Currently, Northwest Pipeline is assessing the actions needed to bring the sites up to Washington's current environmental standards. At December 31, 2005, we have accrued liabilities totaling approximately $4 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline's rates.

We also accrue environmental remediation costs for our natural gas gathering and processing facilities, primarily related to soil and groundwater contamination. At December 31, 2005, we have accrued liabilities totaling approximately $7 million for these costs.

In August 2005, our subsidiary, Williams Production RMT Company, voluntarily disclosed to the Colorado Department of Public Health and Environment (CDPHE) two air permit violations related to malfunctioning equipment. In October 2005, the CDPHE responded to our disclosure indicating that penalty immunity is not available in the matter and that it will seek resolution through a Compliance Order on Consent. We believe that our voluntary self-evaluation and disclosure qualified for penalty immunity and will discuss resolution of the compliance issues with the CDPHE.

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, 2005, we have accrued liabilities of approximately $11 million for such excess costs.

We are in a dispute with a defendant that was involved in two class action damages lawsuits in Florida state court involving this former chemical fertilizer business. Settlement of both class actions was judicially approved in October 2004. We were not a named defendant in the settled lawsuits, but have contractual obligations to participate with the named defendants in the ongoing environmental remediation. One defendant seeks indemnification of approximately $20 million from us as a result of the settlement. In November 2005, the court ordered us to arbitrate the indemnification dispute with the one defendant. The arbitration is expected to occur in the second quarter of 2006. Under the arbitration format, the arbitrator must choose without any modification either our $1 million final offer or the defendant's approximately $20 million final offer.

Other

At December 31, 2005, we have accrued environmental liabilities totaling approximately $28 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.

These costs include certain conditions at specified locations related primarily to soil and groundwater contamination and any penalty assessed on Williams Refining & Marketing, L.L.C. (Williams Refining) associated with noncompliance with the EPA's National Emission Standards for Hazardous Air Pollutants (NESHAP). In 2002, Williams Refining submitted to the EPA a self-disclosure letter indicating noncompliance with those regulations. This unintentional noncompliance had occurred due to a regulatory interpretation that resulted in under-counting the total annual benzene level at Williams Refining's Memphis refinery. Also in 2002, the EPA conducted an all-media audit of the Memphis refinery. In 2004, Williams Refining and the new owner of the Memphis refinery met with the EPA and the DOJ to discuss alleged violations and proposed penalties due to noncompliance issues identified in the report, including the benzene NESHAP issue. On February 2, 2006, the DOJ confirmed our agreement-in-principle to resolve the United States' claims against us for alleged violations. In connection with the sale of the Memphis refinery in 2003, we also have an indemnity dispute with the purchaser.

In 2004, the Oklahoma Department of Environmental Quality (ODEQ) issued a notice of violation (NOV) alleging various air permit violations associated with our operation of the Dry Trail gas processing plant prior to our sale of the facility. The NOV was issued to our subsidiary, Williams Field Services Company (WFS), and the purchaser of the plant. On April 14, 2005, the ODEQ issued a letter to the current Dry Trail plant owners assessing a penalty under the NOV of approximately $750,000. The current owner has asserted an indemnification claim to us for payment of the penalty. We are analyzing the proposed penalty and negotiating a resolution with the current plant owner and the ODEQ.

In 2004, our Gulf Liquids subsidiary initiated a self-audit of all environmental conditions (air, water, waste) at three facilities: 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). No specific penalty amount was assessed. Instead, LDEQ was required by Louisiana law to demand a profit and loss statement to determine the financial benefit obtained by noncompliance and to assess a penalty accordingly. Gulf Liquids offered $91,500 as a single, final, global multi-media settlement. Subsequent negotiations have resulted in a revised offer of $109,000, which LDEQ is currently reviewing.

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.

Other Legal Matters

Royalty indemnifications

We are defending a lawsuit commenced in 1996 in which a producer has asserted a claim against our Transco subsidiary for indemnification relating to prior royalty payments. The producer claimed damages, including interest calculated through December 31, 2005, of approximately $11 million. The Louisiana Court of Appeals affirmed a lower court’s judgment in favor of Transco, and the producer now seeks to have the case reviewed by the Louisiana Supreme Court.

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 on April 1, 2005. We are awaiting a decision from the court.

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 and Texas Gas Transmission Corporation, 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 has 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 was declining to intervene in any of the Grynberg cases, including the action filed in federal court in Colorado against us. 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 remain 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. The District Court is considering whether to affirm or reject the special master’s recommendations and heard oral arguments on December 9, 2005.

On August 6, 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 BTU 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 $1.4 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 has been set for May 2006, but the parties are negotiating an agreement that would eliminate the measurement claims and defer further proceedings on the royalty claims until resolution of an appeal in another case.

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 allege that we and co-defendants, WilTel Communications (WilTel), previously an owned subsidiary known as Williams Communications, and certain corporate officers, have acted jointly and separately to inflate the stock price of both companies. Other suits allege similar causes of action related to a public offering in early January 2002 known as the FELINE PACS offering. These cases were also filed in 2002 against us, certain corporate officers, all members of our board of directors and all of the offerings' underwriters. WilTel is no longer a defendant as a result of its bankruptcy. These cases have all been consolidated and an order has been 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 are currently covering the cost of defending the underwriters. In 2002, the amended complaints of the WilTel securities holders and of our securities holders added numerous claims related to Power. The parties are currently engaged in discovery, and the trial date is currently set for August 16, 2006. Preliminary settlement discussions have occurred. Derivative shareholder suits have been filed in state court in Oklahoma all based on similar allegations. The state court approved motions to consolidate and to stay these Oklahoma suits pending action by the federal court in the shareholder suits. We have directors and officers insurance which we believe provides coverage for these claims. However, it is reasonably possible that the ultimate resolution of this litigation will include some amount outside of insurance coverage. Based on the status of proceedings through the date of this filing, a reasonable estimate of such amount cannot be determined.

In addition, four class action complaints were filed against us, the members of our Board of Directors and members of our benefits and investment committees under the Employee Retirement Income Security Act by participants in our 401(k) plan. In September 2005, the parties agreed to settle these consolidated matters for $55 million. Of this amount, we have paid $5 million and our insurance carriers paid $50 million. This settlement received final approval at a fairness hearing on November 16, 2005. The U.S. Department of Labor was also independently investigating our employee benefit plans but communicated its decision on November 1, 2005, to close its investigation of the 401(k) plan's stock investments.

Federal income tax litigation

One of our wholly-owned subsidiaries, Transco Coal Gas Company, is engaged in a dispute with the Internal Revenue Service (IRS) regarding the recapture of certain income tax credits associated with the construction of a coal gasification plant in North Dakota by Great Plains Gasification Associates, in which Transco Coal Gas Company was a partner. The IRS has taken alternative positions that allege a disposition date for purposes of tax credit recapture that is earlier than the position taken in the partnership tax return. On August 23, 2001, we filed a petition in the U.S. Tax Court to contest the adjustments to the partnership tax return proposed by the IRS. Certain settlement discussions have taken place since that date. During the fourth quarter of 2004, we determined that a reasonable settlement with the IRS could not be achieved. We filed a Motion for Summary Judgment with the Tax Court, which was heard, and denied, in January 2005. The matter was then tried before the Tax Court in February 2005. We continue to believe that the return position of the partnership is with merit. However, it is reasonably possible that the Tax Court could render an unfavorable decision that could ultimately result in estimated income taxes and interest of up to approximately $115 million in excess of the amount currently accrued.

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. Primary issues being litigated include the appropriate valuation of the naphtha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations. Due to the sale of WAPI's interests on March 31, 2004, no future Quality Bank liability will accrue but we are responsible for any liability that existed as of that date including potential liability for any retroactive payments that might be awarded in these proceedings for the period prior to March 31, 2004. In the third quarter of 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions. The initial decisions set forth methodologies for determining the valuations of the product cuts under review and also approved the retroactive application of the approved methodologies for the heavy distillate and residual product cuts. Based on our computation and assessment of ultimate ruling terms that would be considered probable, we recorded an accrual of approximately $134 million in the third quarter of 2004. Because the application of certain aspects of the initial decisions are subject to interpretation, we have calculated the reasonably possible impact of the decisions, if fully adopted by the FERC and RCA, to result in additional exposure to us of approximately $32 million more than we have accrued at December 31, 2005.

On October 20, 2005, the FERC and the RCA issued substantially similar orders regarding the initial decisions. Consistent with the 2005 Highway Reauthorization Bill enacted on August 10, 2005, the two orders eliminate our retroactive exposure for refunds prior to February 1, 2000. The orders also generally affirm the initial decisions except for some modifications to the residual product cuts valuation methodology. We believe the overall impact of the change in retroactive periods precludes our previously disclosed concerns for reasonably possible exposure for amounts in addition to those currently accrued.

In November 2005, ExxonMobil appealed the FERC's decision to the D.C. Circuit Court of Appeals asserting 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. ExxonMobil filed a similar appeal in the Alaska Superior Court. We have appealed the FERC's order to the extent of its ruling on the West Coast Heavy Distillate component. Decisions on these appeals are not expected until late 2006 at the earliest.

Redondo Beach taxes

On February 5, 2005, Power received a tax assessment letter, addressed to AES Redondo Beach, L.L.C. and Power, 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. On the same date, Power was served with a subpoena from the city related to the tax assessment. During July 2005, the city held hearings on this matter. On September 23, 2005, the tax administrator for the city issued a decision in which he found Power jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately $21 million. Both Power and AES Redondo Beach have filed notices of appeal that will be heard at the city level pursuant to a schedule that calls for a final determination by May 19, 2006. On December 19, 2005, Power received additional assessments from the city totaling approximately $3 million in taxes (inclusive of interest and penalties) for the period from October 1, 2004 through September 30, 2005. In late January, 2006, we received an additional assessment totaling approximately $270,000 (inclusive of interest and penalties) for the period from October 1, 2005 through December 31, 2005. Power and AES Redondo Beach have objected to these assessments and have requested a hearing on them. We believe that under Power's tolling agreement related to the Redondo Beach generating facility, AES Redondo Beach is responsible for taxes of the nature asserted by the city; however, AES Redondo Beach has notified us that they do not agree.

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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. Gulsby and Gulsby-Bay defaulted on the construction contracts. In the fall of 2001, the contractors, sureties, and Gulf Liquids filed multiple cases in Louisiana and Texas. In January 2002, NAICO added Gulf Liquids' co-venturer Power to the suits as a third-party defendant. Gulf Liquids has asserted claims against the contractors and sureties for, among other things, breach of contract requesting contractual and consequential damages from $40 million to $80 million, any of which is subject to a sharing arrangement with XL Insurance Company. The contractors and sureties are asserting both contract and tort claims, some of which appear to be duplicative, against Gulf Liquids, Power, and others. The requested contractual and extra-contractual damages range from $20 million to $90 million.

The cases filed in Harris County, Texas, have been consolidated. Various motions for summary judgment are pending before the court. Depending in part on the resolution of these various motions, it is reasonably possible that the contractors and sureties might be awarded damages against us in these various cases for an amount up to $25 million. Trial in the Harris County cases is set for March 27, 2006.

Hurricane lawsuits

We were named as a defendant in two class action petitions for damages filed in the United States District Court for the Eastern District of Louisiana in September and October 2005 arising from hurricanes that struck Louisiana in 2005. The class plaintiffs, purporting to represent all persons, businesses and entities in the State of Louisiana who have suffered damage as a result of the winds and storm surge from the hurricanes, allege that the operating activities of the two sub-classes of defendants, which are all oil and gas pipelines that dredged pipeline canals or installed pipelines in the marshes of south Louisiana (including Transco) and all oil and gas exploration and production companies which drilled for oil and gas or dredged canals in the marshes of south Louisiana, have altered marshland ecology and caused marshland destruction which otherwise would have averted all or almost all of the destruction and loss of life caused by the hurricanes. Plaintiffs request that the court allow the lawsuits to proceed as class actions and seek legal and equitable relief in an unspecified amount. We are presently reviewing the petitions in preparation for filing responsive pleadings in these cases.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided. At December 31, 2005, 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

Power has entered into certain contracts giving it the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States. At December 31, 2005, Power's estimated committed payments under these contracts range from approximately $397 million to $420 million annually through 2017 and decline over the remaining five years to $59 million in 2022. Total committed payments under these contracts over the next seventeen years are approximately $5.9 billion. Total payments made under these contracts during 2005, 2004, and 2003 were $403 million, $402 million, and $394 million, respectively.

Commitments for construction and acquisition of property, plant and equipment are approximately $222 million at December 31, 2005.

Note 16. Related Party Transactions

Lehman Brothers Holdings, Inc.

Lehman Brothers Holdings, Inc. was a related party as a result of a director that served on both our Board of Directors and Lehman Brothers Holdings, Inc.'s Board of Directors. On May 20, 2004, this director retired from our Board of Directors. In 2002, Williams Production RMT Company, a wholly owned subsidiary, entered into a $900 million short-term credit agreement dated July 31, 2002, with certain lenders including a subsidiary of Lehman Brothers Holdings, Inc. This debt obligation was refinanced in second quarter 2003. Included in *interest accrued* on the Consolidated Statement of Operations for 2003 was $199.4 million of interest expense, including amortization of deferred set up fees related to this note. We paid $37.2 million to Lehman Brothers Holdings, Inc. in 2003, primarily for underwriting fees related to debt and equity issuances as well as strategic advisory and restructuring success fees.

American Electric Power Company, Inc.

American Electric Power Company, Inc. (AEP) is a related party as a result of a director that serves on both our Board of Directors and AEP's Board of Directors. In 2003, AEP paid Power $90 million to resolve a dispute involving the liquidation of a trading position. There were no other significant transactions with AEP for the years ended December 31, 2005, 2004, and 2003.

Note 17. Accumulated Other Comprehensive Income (Loss)

The table below presents changes in the components of *accumulated other comprehensive income (loss).*

	Income (Loss)				
	Cash Flow Hedges	Unrealized Appreciation (Depreciation) On Securities	Foreign Currency Translation	Minimum Pension Liability	Total
			(Millions)		
Balance at December 31, 2002	$ 71.3	$ 5.5	$ (23.9)	$ (19.1)	$ 33.8
2003 Change:					
Pre-income tax amount	(408.8)	2.6	77.0	18.2	(311.0)
Income tax benefit (provision)	156.3	(1.0)	—	(6.9)	148.4
Net reclassification into earnings of derivative instrument losses (net of a $9.7 million income tax benefit)	15.6	—	—	—	15.6
Realized gains on securities reclassified into earnings (net of a $5.3 million income tax)	—	(9.0)	—	—	(9.0)
Reclassification into earnings due to sale of bio-energy facilities	—	—	—	1.2	1.2
	(236.9)	(7.4)	77.0	12.5	(154.8)
Balance at December 31, 2003	(165.6)	(1.9)	53.1	(6.6)	(121.0)
2004 Change:					
Pre-income tax amount	(460.9)	(2.4)	15.8	3.0	(444.5)
Income tax benefit (provision)	176.5	.9	—	(1.2)	176.2
Net reclassification into earnings of derivative instrument losses (net of a $87.8 million income tax benefit)	141.7	—	—	—	141.7
Realized losses on securities reclassified into earnings (net of a $2.1 million income tax)	—	3.4	—	—	3.4
	(142.7)	1.9	15.8	1.8	(123.2)
Balance at December 31, 2004	(308.3)	—	68.9	(4.8)	(244.2)
2005 Change:					
Pre-income tax amount	(395.5)	—	11.4	.6	(383.5)
Income tax benefit (provision)	151.3	—	—	(.2)	151.1
Net reclassification into earnings of derivative instrument losses (net of a $110.8 million income tax benefit)	178.8	—	—	—	178.8
	(65.4)	—	11.4	.4	(53.6)
Balance at December 31, 2005	$ (373.7)	$ —	$ 80.3	$ (4.4)	$ (297.8)

Available for Sale Securities

During 2004, we received proceeds totaling $851.4 million from the sale and maturity of available for sale securities. We realized losses of $5.5 million from these transactions. During 2004, all available for sale securities matured or were sold.

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During 2003, we received proceeds totaling $370.5 million from the sale and maturity of available for sale securities. We realized gross gains and losses of $14.4 million and $0.1 million, respectively, from these transactions. At December 31, 2003, we held U.S. Treasury securities with a fair value of $381.3 million. Gross unrealized losses of $3 million on these securities are included in *accumulated other comprehensive income (loss)* at December 31, 2003.

Note 18. 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. Other primarily consists of corporate operations and certain continuing operations that were included within the previously reported International and Petroleum Services segments.

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 *income (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, *Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies*. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

During 2004, Power was party to intercompany interest rate swaps with the corporate parent, the effect of which is included in Power's *segment revenues* and *segment profit (loss)* as shown in the reconciliation within the following tables. We terminated all interest-rate derivatives in the fourth quarter of 2004.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with Power which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with the unrelated third parties. External revenues of our Exploration & Production segment includes third-party oil and gas sales, more than offset by transportation expenses and royalties due third parties on intercompany 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	Total
		(Millions)	
Revenues from external customers:			
2005	$ 12,258.3	$ 325.3	$ 12,583.6
2004	12,167.8	293.5	12,461.3
2003	15,755.8	895.2	16,651.0
Long-lived assets:			
2005	$ 12,692.7	$ 739.8	$ 13,432.5
2004	12,149.0	762.0	12,911.0
2003	11,982.0	776.9	12,758.9

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.

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The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income* as reported in the Consolidated Statement of Operations and *other financial information* related to *long-lived assets*.

	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
				(Millions)			
2005							
Segment revenues:							
External	$ 8,192.5	$ 1,395.0	$ (201.6)	$ 3,187.6	$ 10.1	$ —	$ 12,583.6
Internal	901.4	17.8	1,470.7	45.1	17.1	(2,452.1)	—
Total revenues	$ 9,093.9	$ 1,412.8	$ 1,269.1	$ 3,232.7	$ 27.2	$ (2,452.1)	$ 12,583.6
Segment profit (loss)	$ (256.7)	$ 585.8	$ 587.2	$ 471.2	$ (105.0)	$ —	$ 1,282.5
Less:							
Equity earnings (losses)	3.1	43.6	18.8	23.6	(23.5)	—	65.6
Income (loss) from investments	(23.0)	—	—	1.0	(87.1)	—	(109.1)
Segment operating income (loss)	$ (236.8)	$ 542.2	$ 568.4	$ 446.6	$ 5.6	$ —	1,326.0
General corporate expenses							(154.9)
Consolidated operating income							$ 1,171.1
Other financial information:							
Additions to long-lived assets	$ 5.9	$ 420.2	$ 794.7	$ 133.2	$ 4.7	$ —	$ 1,358.7
Depreciation, depletion & amortization	$ 14.9	$ 267.3	$ 254.2	$ 192.0	$ 11.6	$ —	$ 740.0
2004							
Segment revenues:							
External	$ 8,346.2	$ 1,345.0	$ (84.0)	$ 2,844.7	$ 9.4	$ —	$ 12,461.3
Internal	912.5	17.3	861.6	37.9	23.4	(1,852.7)	—
Total segment revenues	9,258.7	1,362.3	777.6	2,882.6	32.8	(1,852.7)	12,461.3
Less intercompany interest rate swap loss	(13.7)	—	—	—	—	13.7	—
Total revenues	$ 9,272.4	$ 1,362.3	$ 777.6	$ 2,882.6	$ 32.8	$ (1,866.4)	$ 12,461.3
Segment profit (loss)	$ 76.7	$ 585.8	$ 235.8	$ 549.7	$ (41.6)	$ —	$ 1,406.4
Less:							
Equity earnings (losses)	3.9	29.2	11.9	14.6	(9.7)	—	49.9
Loss from investments	—	(1.0)	—	(17.1)	(17.4)	—	(35.5)
Intercompany interest rate swap loss	(13.7)	—	—	—	—	—	(13.7)
Segment operating income (loss)	$ 86.5	$ 557.6	$ 223.9	$ 552.2	$ (14.5)	$ —	1,405.7
General corporate expenses							(119.8)
Consolidated operating income							$ 1,285.9
Other financial information:							
Additions to long-lived assets	$ 1.0	$ 300.1	$ 445.4	$ 91.3	$ 6.0	$ —	$ 843.8
Depreciation, depletion & amortization	$ 20.1	$ 264.4	$ 192.3	$ 178.4	$ 13.3	$ —	$ 668.5
2003							
Segment revenues:							
External	$ 12,570.5	$ 1,344.3	$ (36.3)	$ 2,740.2	$ 32.3	$ —	$ 16,651.0
Internal	622.1	24.0	816.0	44.6	39.7	(1,546.4)	—
Total segment revenues	13,192.6	1,368.3	779.7	2,784.8	72.0	(1,546.4)	16,651.0
Less intercompany interest rate swap loss	(2.9)	—	—	—	—	2.9	—
Total revenues	$ 13,195.5	$ 1,368.3	$ 779.7	$ 2,784.8	$ 72.0	$ (1,549.3)	$ 16,651.0
Segment profit (loss)	$ 135.1	$ 555.5	$ 401.4	$ 197.3	$ (50.5)	$ —	$ 1,238.8
Less:							
Equity earnings (losses)	(4.9)	15.8	8.9	(.8)	1.3	—	20.3
Income (loss) from investments	(2.4)	0.1	—	20.1	(43.1)	—	(25.3)
Intercompany interest rate swap loss	(2.9)	—	—	—	—	—	(2.9)
Segment operating income (loss)	$ 145.3	$ 539.6	$ 392.5	$ 178.0	$ (8.7)	$ —	1,246.7
General corporate expenses							(87.0)
Consolidated operating income							$ 1,159.7
Other financial information:							
Additions to long-lived assets	$ 1.0	$ 517.4	$ 241.5	$ 255.0	$ 2.5	$ —	$ 1,017.4
Depreciation, depletion & amortization	$ 31.5	$ 274.6	$ 173.9	$ 157.7	$ 19.7	$ —	$ 657.4

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The following table reflects *total assets* and *equity method investments* by reporting segment.

	Total Assets			Equity Method Investments		
	December 31, 2005	December 31, 2004	December 31, 2003	December 31, 2005	December 31, 2004	December 31, 2003
			(Millions)			
Power(1)	$ 14,989.2	$ 8,204.1	$ 8,732.9	$ 19.2	$ 45.6	$ 42.8
Gas Pipeline	7,581.0	7,651.8	7,314.3	439.1	769.5	774.4
Exploration & Production(2)	8,672.0	5,576.4	5,347.4	58.4	44.9	41.5
Midstream Gas & Liquids	4,677.7	4,211.7	4,050.4	314.2	273.3	289.9
Other(3)	3,929.9	3,584.0	6,928.7	.2	113.2	85.1
Eliminations(4)	(10,420.0)	(5,248.6)	(6,078.2)	—	—	—
	29,429.8	23,979.4	26,295.5	831.1	1,246.5	1,233.7
Net assets of discontinued operations(5)	12.8	13.6	726.3	—	—	—
Total assets	$ 29,442.6	$ 23,993.0	$ 27,021.8	$ 831.1	$ 1,246.5	$ 1,233.7

(1) The 2005 increase in Power’s total assets is due primarily to an increase in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Power’s derivative assets are substantially offset by their derivative liabilities.

(2) The 2005 increase in Exploration & Production’s total assets is due primarily to an increase in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Exploration & Production’s derivatives are primarily comprised of intercompany transactions with the Power segment.

(3) The 2004 decrease in Other’s total assets is due primarily to cash payments on existing debt.

(4) The 2005 increase in Eliminations is due primarily to an increase in the intercompany derivative balances.

(5) The 2004 decrease in net assets of discontinued operations is due to the sale of our Canadian straddle plants during 2004.

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
2005				
Revenues	$ 2,954.0	$ 2,871.2	$ 3,082.3	$ 3,676.1
Costs and operating expenses	2,390.3	2,491.6	2,826.2	3,162.9
Income from continuing operations	202.2	40.7	5.7	68.8
Income before cumulative effect of change in accounting principle	201.1	41.3	4.4	68.5
Net income	201.1	41.3	4.4	66.8
Basic earnings per common share:				
Income from continuing operations	.36	.07	.01	.12
Income before cumulative effect of change in accounting principle	.36	.07	.01	.12
Diluted earnings per common share:				
Income from continuing operations	.34	.07	.01	.11
Income before cumulative effect of change in accounting principle	.34	.07	.01	.11
2004				
Revenues	$ 3,070.0	$ 3,051.9	$ 3,375.2	$ 2,964.2
Costs and operating expenses	2,690.9	2,661.4	2,855.9	2,543.5
Income (loss) from continuing operations	—	(18.5)	16.2	95.5
Net income (loss)	9.9	(18.2)	98.6	73.4
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	—	(.03)	.03	.17
Net income (loss)	.02	(.03)	.19	.13
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	—	(.03)	.03	.17
Net income (loss)	.02	(.03)	.19	.13

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 2005 includes a $20.2 million reduction to the tax provision associated with an adjustment to deferred income taxes (see Note 5) and the following pre-tax items:

- $68.7 million accrual for litigation contingencies at Power (see Note 4);
- $38.1 million impairment of our investment in Longhorn at Other (see Note 3);
- $32.1 million charge related to accounting and valuation corrections for certain inventory items at Gas Pipeline (see Note 4);
- $23 million impairment of our investment in Aux Sable at Power (see Note 3);
- $5.2 million accrual for contingent refund obligations at Gas Pipeline (see Note 4).

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA — (Continued)
(Unaudited)

Net income for third quarter 2005 includes the following pre-tax items:

- $21.7 million gain on sale of certain natural gas properties at Exploration & Production (see Note 4);
- $14.2 million of income from the reversal of a liability due to resolution of litigation at Gas Pipeline (see Note 4);
- $13.8 million increase in expense related to the settlement of certain insurance coverage issues associated with ERISA and securities litigation at Other (see Note 4).

Net income for second quarter 2005 includes the following pre-tax items:

- $49.1 million impairment of our investment in Longhorn at Other (see Note 3);
- $17.1 million reduction of expense at Gas Pipeline to correct the overstatement of pension expense in prior periods (see Note 7);
- $13.1 million accrual for litigation contingencies at Power (see Note 4);
- $8.6 million gain on sale of our remaining interests in Mid-America Pipeline and Seminole Pipeline at Midstream.

Net income for first quarter 2005 includes the following pre-tax items:

- $13.1 million of income due to the reversal of certain prior period accruals at Gas Pipeline;
- $7.9 million gain on sale of certain natural gas properties at Exploration & Production (see Note 4).

Net income for fourth quarter 2004 includes the following pre-tax items:

- $93.6 million income from Gulf Liquids insurance arbitration award and related interest income of $9.6 million at Midstream (see Note 4);
- $11.8 million expense related to an environmental accrual for the Augusta refinery facility at Other (see Note 4);
- $16.9 million impairment of our investment in Discovery Pipeline at Midstream (see Note 3);
- $29.5 million costs associated with the FELINE PACS exchange and remarketing at Other.

Net income for third quarter 2004 includes the following pre-tax items:

- $16.5 million reduction of revenue attributable to the second quarter of 2004 as a result of Midstream's correction of their revenue recognition methodology related to the Devils Tower facility;
- $155.1 million premiums, fees and expenses related to the third quarter 2004 cash tender offer and consent solicitations at Other;
- $15.7 million impairment of an international cost-based investment, included at Other (see Note 3);
- $127.0 million loss from discontinued operations (see Note 2);
- $192.9 million of gains on discontinued operations, net of losses on sales and impairments (see Note 2).

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Net loss for second quarter 2004 includes the following pre-tax items:

- $9.0 million charge resulting from the write-off of previously capitalized costs on an idled segment of a pipeline at Gas Pipeline (see Note 4);
- $10.1 million benefit from the reversal of a default reserve on good faith negotiations at Power;
- $11.3 million expense related to a loss provision regarding an ownership dispute on prior period production at Exploration & Production (see Note 4);
- $10.8 million impairment of our investment in Longhorn at Other (see Note 3);
- $16.5 million increase in revenues related to the Devils Tower facility subsequently reversed in third quarter 2004 due to a revenue recognition methodology correction at Midstream;
- $96.8 million premiums, fees and expenses related to the second quarter 2004 cash tender offer at Other.

Net income for first quarter 2004 includes the following pre-tax items:

- $13.0 million charge resulting from the termination of a nonderivative power sales contract at Power;
- $6.5 million net unreimbursed Longhorn recapitalization advisory fees at Other (see Note 3);
- $8.7 million income from discontinued operations (see Note 2);
- $6.9 million of gains on sales of discontinued operations, net of losses on sales and impairments (see Note 2).

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 oil and gas producing activities in Argentina and Venezuela. However, proved reserves and revenues related to international activities are approximately 6.2 percent and 4.2 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 and includes the activities of those properties that qualified for reporting as discontinued operations in the Consolidated Statement of Operations.

Capitalized costs

	As of December 31, 2005	As of December 31, 2004
	(Millions)	
Proved properties	$ 3,870.5	$ 3,022.9
Unproved properties	503.1	569.7
	4,373.6	3,592.6
Accumulated depreciation, depletion and amortization and valuation provisions	(937.4)	(688.3)
Net capitalized costs	$ 3,436.2	$ 2,904.3

- Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These amounts for 2005 and 2004 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 and related equipment and facilities (including uncompleted development well costs); and successful exploratory wells and related equipment and facilities.
- Unproved properties consist primarily of acreage related to probable/possible reserves acquired through the Barrett acquisition in 2001 and a property acquisition in 2005. The balance is unproved exploratory acreage.

Costs incurred

	For the Year Ended December 31, 2005	2004	2003
		(Millions)	
Acquisition	$ 45.3	$ 17.2	$ 11.3
Exploration	8.3	4.5	7.1
Development	723.1	419.2	186.8
	$ 776.7	$ 440.9	$ 205.2

- Costs incurred include capitalized and expensed items.
- Acquisition costs are as follows: 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. The 2004 costs relate to the Huber-Edwards reserve acquisition in the San Juan Basin, RBS, and additional land

acquisitions in the Arkoma basin, and Guthrie leasehold acquisition in the Powder River basin. The 2003 costs relates to the Smith, Contra, Tailwind acquisition also in the Arkoma basin at the end of 2003.

• 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 inclusive of related gathering facilities.

Results of operations

	For the Year Ended December 31,		
	2005	2004	2003
		(Millions)	
Revenues:			
Oil and gas revenues	$ 1,072.4	$ 599.9	$ 611.9
Other revenues	143.3	137.3	168.8
Total revenues	1,215.7	737.2	780.7
Costs:			
Production costs	230.3	165.4	138.3
General & administrative	79.5	58.3	54.4
Exploration expenses	8.3	4.5	7.1
Depreciation, depletion & amortization	244.7	183.4	170.2
(Gains)/ Losses on sales of interests in oil and gas properties	(30.8)	0.1	(134.8)
Other expenses	141.1	115.2	102.1
Total costs	673.1	526.9	337.3
Results of operations	542.6	210.3	443.4
Provision for income taxes	(216.9)	(81.4)	(169.6)
Exploration and production net income	$ 325.7	$ 128.9	$ 273.8

• Results of operations for producing activities consist of all related domestic activities within the Exploration & Production reporting unit, including those operations that qualified for presentation as discontinued operations within our Consolidated Statement of Operations. Included above are the pretax results of operations and gains on sales of assets, reported as discontinued operations, of $60.2 million in 2003. Other expenses in 2005 and 2004 include a $6 million and $16 million gain, respectively, on sales of securities associated with a coal seam royalty trust.

• Oil and gas revenues consist primarily of natural gas production sold to the Power subsidiary and includes the impact of 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 non-producing 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 Power subsidiary or third party purchasers. In addition, other revenues include recognition of income from transactions which transferred certain non-operating 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 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.

- Depreciation, depletion and amortization includes depreciation of support equipment.

Proved reserves

	2005	2004	2003
		(Bcfe)	
Proved reserves at beginning of period	2,986	2,703	2,834
Revisions	(12)	(70)	(5)
Purchases	28	24	38
Extensions and discoveries	615	521	412
Production	(224)	(191)	(186)
Sale of minerals in place	(11)	(1)	(390)
Proved reserves at end of period	3,382	2,986	2,703
Proved developed reserves at end of period	1,643	1,348	1,165

- 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 $6.95, $5.08, and $5.28 per mmcfe at December 31, 2005, 2004, and 2003, respectively. Future income tax expenses have been computed

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES — (Continued)
(Unaudited)

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 $2,258 million of future development costs, $661 million, $727 million and $610 million are estimated to be spent in 2006, 2007 and 2008, respectively.

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, 2005	At December 31, 2004
	(Millions)	
Future cash inflows	$ 23,510	$ 15,174
Less:		
Future production costs	4,441	3,027
Future development costs	2,258	1,703
Future income tax provisions	6,128	3,744
Future net cash flows	10,683	6,700
Less 10 percent annual discount for estimated timing of cash flows	5,402	3,553
Standardized measure of discounted future net cash flows	$ 5,281	$ 3,147

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES — (Continued)
(Unaudited)

Sources of change in standardized measure of discounted future net cash flows

	2005	2004	2003
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 3,147	$ 3,349	$ 2,272
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,222)	(835)	(567)
Net change in prices and production costs	2,358	(306)	2,001
Extensions, discoveries and improved recovery, less estimated future costs	1,310	787	901
Development costs incurred during year	723	419	187
Changes in estimated future development costs	(300)	(696)	(159)
Purchase of reserves in place, less estimated future costs	78	29	78
Sales of reserves in place, less estimated future costs	(31)	(3)	(855)
Revisions of previous quantity estimates	(28)	(90)	(11)
Accretion of discount	488	286	341
Net change in income taxes	(1,272)	182	(773)
Other	30	25	(66)
Net changes	2,134	(202)	1,077
Standardized measure of discounted future net cash flows end of period	$ 5,281	$ 3,147	$ 3,349

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, 2005:					
Allowance for doubtful accounts — accounts and notes receivable(a)	$ 98.8	$ 3.5	$ —	$ 15.7(c)	$ 86.6
Price-risk management credit reserves(a)	26.4	(2.6)(d)	13.2(e)	—	37.0
Processing plant major maintenance accrual(b)	5.7	1.5	—	—	7.2
Year ended December 31, 2004:					
Allowance for doubtful accounts — accounts and notes receivable(a)	112.2	(.8)	—	12.6(c)	98.8
Price-risk management credit reserves(a)	39.8	(12.8)(d)	(.6)(e)	—	26.4
Processing plant major maintenance accrual(b)	4.1	1.6	—	—	5.7
Year ended December 31, 2003:					
Allowance for doubtful accounts — accounts and notes receivable(a)	111.8	7.3	7.9(f)	14.8(c)	112.2
Price-risk management credit reserves(a)	250.4	2.6(d)	—	213.2(g)	39.8
Processing plant major maintenance accrual(b)	2.7	1.4	—	—	4.1

(a) Deducted from related assets.

(b) Included in *other liabilities and deferred income.*

(c) Represents balances written off, reclassifications, and recoveries.

(d) Included in *revenues.*

(e) Included in *accumulated other comprehensive loss.*

(f) Reflects allowances for accounts receivable charged to *costs and expenses* for a discontinued operation whose receivables were not held for sale.

(g) Reflects *cumulative effect of change in accounting principle* related to EITF 02-3 (see Note 1 of Notes to Consolidated Financial Statements).

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.

Fourth Quarter 2005 Changes in Internal Control Over Financial Reporting

On October 1, 2005, we completed the final phase of system implementations which are part of an enterprise initiative to move to common enterprise accounting systems. This phase impacted our Exploration & Production business segment and represented a replacement of the primary accounting systems used to process, accumulate and summarize accounting information. In addition, the systems implemented also replaced previous systems used to manage land lease records and division order interests. As a result, some processes and related controls were modified to address any changes resulting from the system implementation.

Other than as described above, there have been no changes in our internal controls over financial reporting during the fourth quarter that 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 and Executive Officers of the Registrant***

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", "Election of Directors", and "Principal Accounting Fees and Services" in our Proxy Statement prepared for the solicitation of proxies in connection with our Annual Meeting of Stockholders to be held May 18, 2006 (Proxy Statement), which information is incorporated by reference herein.

Information regarding our executive officers required by Item 401 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.

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 of Regulation S-K regarding executive compensation will be presented under the headings "Board of Directors" and "Executive Compensation and Other Information" in our Proxy Statement, which information is incorporated by reference herein. Notwithstanding the foregoing, the information provided under the headings "Compensation Committee Report on Executive Compensation" and "Stockholder Return Performance Presentation" in our Proxy Statement is not incorporated by reference herein.

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***

The information regarding certain relationships and related transactions required by Item 404 of Regulation S-K will be presented under the heading "Certain Relationships and Related Transactions" 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
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 our 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*	—	Sixth Supplemental Indenture dated January 14, 2002, between Williams and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to our Form 8-K filed January 23, 2002).
4.7*	—	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).

Exhibit No.		Description
4.8*	—	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).
4.9*	—	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 our Form 10-K for the fiscal year ended December 31, 1999).
4.10*	—	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).
4.11*	—	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).
4.12*	—	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).
4.13*	—	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).
4.14*	—	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).
4.15*	—	Revised Form of Indenture between Barrett Resources Corporation, as Issuer, and Bankers Trust Company, as Trustee, with respect to Senior Notes including specimen of 7.55% Senior Notes (filed as Exhibit 4.1 to Barrett Resources Corporation's Amendment No. 2 to our Registration Statement on Form S-3 filed February 10, 1997).
4.16*	—	First Supplemental Indenture dated 2001, between Barrett Resources Corporation, as Issuer, and Bankers Trust Company, as Trustee (filed as Exhibit 4.3 to our Form 10-Q filed November 13, 2001).
4.17*	—	Second Supplemental Indenture dated as of August 2, 2001, among Barrett Resources Corporation, as Issuer, Resources Acquisition Corp., The Williams Companies, Inc. and Bankers Trust Company, as Trustee (filed as Exhibit 4.4 to our Form 10-Q filed November 13, 2001).
4.18*	—	Third Supplemental Indenture dated as of May 20, 2004 with respect to the Indenture dated as of February 1, 1997 between Barrett Resources Corporation (predecessor-in-interest to Williams Production RMT Company) and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee (filed as Exhibit 99.2 to our Form 8-K filed May 20, 2004).
4.19*	—	Form of Note (filed as Exhibit 4.2 and included in Exhibit 4.1 to our Form 8-K filed January 23, 2002).
4.20*	—	Purchase Contract Agreement dated January 14, 2002, between Williams and JPMorgan Chase Bank, as Purchase Contract Agent (filed as Exhibit 4.3 to our Form 8-K filed January 23, 2002).
4.21*	—	Form of Income PACS Certificate (filed as Exhibit 4.4 and included in Exhibit 4.3 to our Form 8-K filed January 23, 2002).
4.22*	—	Pledge Agreement dated January 14, 2002, among Williams, Bank, as Purchase Contract Agent (filed as Exhibit 4.5 to our Form 8-K filed January 23, 2002).
4.23*	—	Remarketing Agreement dated January 14, 2002, among Williams, JPMorgan Chase Bank, as Purchase Contract Agent, and Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Remarketing Agent (filed as Exhibit 4.6 to our Form 8-K filed January 23, 2002).

Exhibit No.		Description
4.24*	—	Supplemental Remarketing Agreement dated as of November 4, 2004 by and among Williams, Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporation, as Remarketing Agent, and JPMorgan Chase Bank, as Purchase Contract Agent (filed as exhibit 99.1 to our Form 8-K filed November 9, 2004).
4.25*	—	Indenture dated March 4, 2003, between Northwest Pipeline Corporation and JP Morgan Chase Bank, as Trustee (filed as Exhibit 4.1 to our Form 10-Q filed May 13, 2003.
4.26*	—	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).
4.27*	—	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.
4.28*	—	Senior Indenture, dated as of August 1, 1992, between Northwest Pipeline Corporation and Continental Bank, N.A., Trustee with regard to Northwest Pipeline's 9% Debentures, due 2022 (filed as Exhibit 4.1 to Northwest Pipeline's Form S-3 filed July 2, 1992).
4.29*	—	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee with regard to Northwest Pipeline's 7.125% Debentures, due 2025 (filed as Exhibit 4.1 to Northwest Pipeline's Form S-3 filed September 14, 1995)
4.30*	—	Senior Indenture, dated as of December 8, 1997, between Northwest Pipeline Corporation and The Chase Manhattan Bank, Trustee with regard to Northwest Pipeline's 6.625% Debentures, due 2007 (filed as Exhibit 4.1 to Northwest Pipeline's Form S-3 filed September 8, 1997)
4.31*	—	Senior Indenture dated as of July 15, 1996 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 April 2, 1996)
4.32*	—	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)
4.33*	—	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)
4.34*	—	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)
4.35*	—	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).
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. 1988 Stock Option Plan for Non-Employee Directors (filed as Exhibit A to our Proxy Statement dated March 14, 1988).
10.5*	—	The Williams Companies, Inc. 1990 Stock Plan (filed as Exhibit A to our Proxy Statement dated March 12, 1990).
10.6*	—	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).

Exhibit No.		Description
10.7*	—	The Williams Companies, Inc. 1996 Stock Plan (filed as Exhibit A to our Proxy Statement dated March 27, 1996).
10.8*	—	The Williams Companies, Inc. 1996 Stock Plan for Non-employee Directors (filed as Exhibit B to our Proxy Statement dated March 27, 1996).
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*	—	The Williams International Stock Plan (filed as Exhibit 10(iii)(l) to our Form 10-K for the fiscal year ended December 31, 1998).
10.11*	—	Form of Stock Option Secured Promissory Note and Pledge Agreement among Williams and certain employees, officers and non-employee directors (filed as Exhibit 10(iii)(m) to our Form 10-K for the fiscal year ended December 31, 1998).
10.12*	—	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).
10.13*	—	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).
10.14*	—	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).
10.15*	—	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).
10.16*	—	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).
10.17*	—	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 4.1 to our Form S-8 filed August 1, 2001).
10.18*	—	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).
10.19*	—	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).
10.20*	—	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).
10.21	—	The Williams Companies, Inc. Severance Pay Plan as Amended and Restated Effective October 28, 2003.
10.22	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated October 28, 2003.
10.23	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated June 1, 2004.
10.24	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated January 1, 2005.
10.25*	—	U.S. $500,000,000 Term Loan Agreement among Williams Production Holdings LLC, Williams Production RMT Company, as Borrower, the Several Lenders from time to time parties thereto, Lehman Brothers Inc. and Banc of America Securities LLC as Joint Lead Arrangers, Citigroup USA, Inc. and JPMorgan Chase Bank, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and Lehman Commercial Paper Inc., as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.1 to our Form 10-Q filed August 12, 2003).
10.26*	—	The First Amendment to the Term Loan Agreement dated February 25, 2004, between Williams Production Holdings, LLC, Williams Production RMT Company, as Borrower, the several financial institutions as lenders and Lehman Commercial Paper Inc., as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.3 to our Form 10-Q filed May 6, 2004).

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Exhibit No.		Description
10.27*	—	Guarantee and Collateral Agreement made by Williams Production Holdings LLC, Williams Production RMT Company and certain of its Subsidiaries in favor of Lehman Commercial Paper Inc. as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.2 to our Form 10-Q filed August 12, 2003).
10.28*	—	U.S. $1,000,000,000 Credit Agreement dated as of May 3, 2004, among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipeline Corporation, as Borrowers, Citicorp USA, Inc., as Administrative Agent and Collateral Agent, Citibank, N.A. and Bank of America, N.A., Collateral Agent, Citibank, N.A. and Bank of America, N.A., as Issuing Banks, the banks named therein as Banks, Bank of America, N.A., as Syndication Agent, JPMorgan Chase Bank, The Bank of Nova Scotia, The Royal Bank of Scotland plc as Co-Documentation Agents, Citigroup Global Markets Inc. and Banc of America Securities LLC as Joint Lead Arrangers and Co-Book Runners (filed as Exhibit 10.4 to our Form 10-Q filed May 6, 2004).
10.29*	—	Letter of Credit Commitment Increase Agreement dated August 4, 2004, by and among The Williams Companies, Inc., Citicorp USA in its capacity as Agent under the Credit Agreement dated as of May 3, 2004 among the Borrower, Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, the Agent, the Collateral Agent, the Banks and Issuing Banks party thereto and Citibank, N.A. and Bank of America, N.A. (filed as Exhibit 10.1 to our Form 10-Q filed November 4, 2004).
10.30*	—	Revolving Credit Commitment Increase Agreement dated August 4, 2004, by and among The Williams Companies, Inc., Citicorp USA in its capacity as Agent under the Credit Agreement dated as of May 3, 2004 among the Borrower, Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, the Agent, the Collateral Agent and the Banks and Issuing Banks party thereto, the Issuing Banks and Citicorp USA, Inc. (filed as Exhibit 10.2 to our Form 10-Q filed November 4, 2004).
10.31*	—	U.S. $1,275,000,000 Amended and Restated Credit Agreement Dated as of May 20, 2005 among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, Williams Partners L.P., as Borrowers, Citicorp USA, Inc., As Administrative Agent and Collateral Agent, Citibank, N.A. Bank of America, N.A. as Issuing Banks and The Banks Named Herein as Banks (filed as Exhibit 1.1 to our Form 8-K filed May 26, 2005).
10.32*	—	Amendment Agreement dated as of October 19, 2004 among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipeline Corporation, as Borrowers, the banks, financial institutions and other institutional lenders that are parties to the Credit Agreement dated as of May 3, 2004 among the Borrowers, the Banks, Citicorp USA, Inc., as agent and Citibank, N.A. and Bank of America, N.A., as issuers of letters of credit under the Credit Agreement, the Agent and the Issuing Banks (filed as Exhibit 10.29 to our Form 10-K filed March 11, 2005).
10.33*	—	Western Midstream Security Agreement dated as of May 3, 2004, among Williams Gas Processing Company, Williams Field Services Company, Williams Gas Processing — Wamsutter Company as Grantors, in favor of Citicorp USA, Inc. as Collateral Agents (filed as Exhibit 10.5 to our Form 10-Q filed May 6, 2004).
10.34*	—	Pledge Agreement dated as of May 3, 2004, by Williams Field Services Group, Inc. in favor of Citicorp USA, Inc. as Collateral Agent (filed as Exhibit 10.6 to our Form 10-Q filed May 6, 2004).
10.35*	—	Western Midstream Guaranty by Williams Gas Processing Company, Williams Field Services Company, Williams Gas Processing — Wamsutter Company as Guarantors in favor of Citicorp USA, Inc. as Collateral Agent (filed as Exhibit 10.7 to our Form 10-Q filed May 6, 2004).
10.36*	—	Pipeline Holdco Guaranty by Williams Gas Pipeline Company, LLC as Guarantor in favor of Citicorp USA, Inc. as Collateral Agent (filed as Exhibit 10.8 to our Form 10-Q filed May 6, 2004).
10.37*	—	Amended and Restated U.S. $400,000,000 Five Year Credit Agreement dated April 14, 2004 and amended 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 10.1 to our Form 8-K filed on January 26, 2005).

Exhibit No.		Description
10.38*	—	Amended and Restated U.S. $100,000,000 Five Year Credit Agreement dated April 26, 2004 and amended 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 10.2 to our Form 8-K filed on January 26, 2005).
10.39*	—	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).
10.40*	—	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).
10.41*	—	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 10.3 to our Form 8-K filed on September 26, 2005).
10.42*	—	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 10.3 to our Form 8-K filed on September 26, 2005).
10.43*	—	New Omnibus Agreement among WEG Acquisitions, L.P., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and The Williams Companies, Inc. dated as of June 17, 2003 (filed as Exhibit 10.9 to our Form 10-Q filed August 12, 2003).
10.44*	—	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).
10.45*	—	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).
10.46*	—	Sale Agreement Relating to the Sale of the Interest of Williams Energy (Canada), Inc. in the Cochrane, Empress II and Empress V Straddle Plants dated as of July 8, 2004 between Williams Energy (Canada), Inc. and 1024234 Alberta Ltd. (filed as Exhibit 10.7 to our Form 10-Q filed August 5, 2004).
10.47*	—	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).
10.48*	—	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).
10.49*	—	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).
10.50*	—	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).
10.51*	—	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).
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 2006 (to be filed with the Securities and Exchange Commission on or before April 10, 2006).

Exhibit No.		Description
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: March 9, 2006

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)	March 9, 2006
/s/ DONALD R. CHAPPEL* Donald R. Chappel	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 9, 2006
/s/ TED T. TIMMERMANS* Ted T. Timmermans	Controller (Principal Accounting Officer)	March 9, 2006
/s/ IRL F. ENGELHARDT* Irl F. Engelhardt	Director	March 9, 2006
/s/ WILLIAM R. GRANBERRY* William R. Granberry	Director	March 9, 2006
/s/ WILLIAM E. GREEN* William E. Green	Director	March 9, 2006
/s/ JUANITA H. HINSHAW* Juanita H. Hinshaw	Director	March 9, 2006
/s/ W.R. HOWELL* W.R. Howell	Director	March 9, 2006
/s/ CHARLES M. LILLIS* Charles M. Lillis	Director	March 9, 2006
/s/ GEORGE A. LORCH* George A. Lorch	Director	March 9, 2006
/s/ WILLIAM G. LOWRIE* William G. Lowrie	Director	March 9, 2006

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Signature	Title	Date
/s/ FRANK T. MACINNIS*	Director	March 9, 2006
Frank T. Macinnis		
/s/ JANICE D. STONEY*	Director	March 9, 2006
Janice D. Stoney		
/s/ JOSEPH H. WILLIAMS*	Director	March 9, 2006
Joseph H. Williams		
*By: /s/ BRIAN K. SHORE		March 9, 2006
Brian K. Shore *Attorney-in-fact*		

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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
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*	—	Sixth Supplemental Indenture dated January 14, 2002, between Williams and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to our Form 8-K filed January 23, 2002).
4.7*	—	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).
4.8*	—	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).
4.9*	—	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).
4.10*	—	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).
4.11*	—	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).
4.12*	—	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).
4.13*	—	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).
4.14*	—	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).
4.15*	—	Revised Form of Indenture between Barrett Resources Corporation, as Issuer, and Bankers Trust Company, as Trustee, with respect to Senior Notes including specimen of 7.55% Senior Notes (filed as Exhibit 4.1 to Barrett Resources Corporation's Amendment No. 2 to our Registration Statement on Form S-3 filed February 10, 1997).
4.16*	—	First Supplemental Indenture dated 2001, between Barrett Resources Corporation, as Issuer, and Bankers Trust Company, as Trustee (filed as Exhibit 4.3 to our Form 10-Q filed November 13, 2001).

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Exhibit No.		Description
4.17*	—	Second Supplemental Indenture dated as of August 2, 2001, among Barrett Resources Corporation, as Issuer, Resources Acquisition Corp., The Williams Companies, Inc. and Bankers Trust Company, as Trustee (filed as Exhibit 4.4 to our Form 10-Q filed November 13, 2001).
4.18*	—	Third Supplemental Indenture dated as of May 20, 2004 with respect to the Indenture dated as of February 1, 1997 between Barrett Resources Corporation (predecessor-in-interest to Williams Production RMT Company) and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee (filed as Exhibit 99.2 to our Form 8-K filed May 20, 2004).
4.19*	—	Form of Note (filed as Exhibit 4.2 and included in Exhibit 4.1 to our Form 8-K filed January 23, 2002).
4.20*	—	Purchase Contract Agreement dated January 14, 2002, between Williams and JPMorgan Chase Bank, as Purchase Contract Agent (filed as Exhibit 4.3 to our Form 8-K filed January 23, 2002).
4.21*	—	Form of Income PACS Certificate (filed as Exhibit 4.4 and included in Exhibit 4.3 to our Form 8-K filed January 23, 2002).
4.22*	—	Pledge Agreement dated January 14, 2002, among Williams, Bank, as Purchase Contract Agent (filed as Exhibit 4.5 to our Form 8-K filed January 23, 2002).
4.23*	—	Remarketing Agreement dated January 14, 2002, among Williams, JPMorgan Chase Bank, as Purchase Contract Agent, and Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Remarketing Agent (filed as Exhibit 4.6 to our Form 8-K filed January 23, 2002).
4.24*	—	Supplemental Remarketing Agreement dated as of November 4, 2004 by and among Williams, Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporation, as Remarketing Agent, and JPMorgan Chase Bank, as Purchase Contract Agent (filed as exhibit 99.1 to our Form 8-K filed November 9, 2004).
4.25*	—	Indenture dated March 4, 2003, between Northwest Pipeline Corporation and JP Morgan Chase Bank, as Trustee (filed as Exhibit 4.1 to our Form 10-Q filed May 13, 2003.
4.26*	—	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).
4.27*	—	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.
4.28*	—	Senior Indenture, dated as of August 1, 1992, between Northwest Pipeline Corporation and Continental Bank, N.A., Trustee with regard to Northwest Pipeline’s 9% Debentures, due 2022 (filed as Exhibit 4.1 to Northwest Pipeline’s Form S-3 filed July 2, 1992).
4.29*	—	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee with regard to Northwest Pipeline’s 7.125% Debentures, due 2025 (filed as Exhibit 4.1 to Northwest Pipeline’s Form S-3 filed September 14, 1995)
4.30*	—	Senior Indenture, dated as of December 8, 1997, between Northwest Pipeline Corporation and The Chase Manhattan Bank, Trustee with regard to Northwest Pipeline’s 6.625% Debentures, due 2007 (filed as Exhibit 4.1 to Northwest Pipeline’s Form S-3 filed September 8, 1997)
4.31*	—	Senior Indenture dated as of July 15, 1996 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 April 2, 1996)
4.32*	—	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)
4.33*	—	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)
4.34*	—	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)

Exhibit No.		Description
4.35*	—	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).
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. 1988 Stock Option Plan for Non-Employee Directors (filed as Exhibit A to our Proxy Statement dated March 14, 1988).
10.5*	—	The Williams Companies, Inc. 1990 Stock Plan (filed as Exhibit A to our Proxy Statement dated March 12, 1990).
10.6*	—	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).
10.7*	—	The Williams Companies, Inc. 1996 Stock Plan (filed as Exhibit A to our Proxy Statement dated March 27, 1996).
10.8*	—	The Williams Companies, Inc. 1996 Stock Plan for Non-employee Directors (filed as Exhibit B to our Proxy Statement dated March 27, 1996).
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*	—	The Williams International Stock Plan (filed as Exhibit 10(iii)(l) to our Form 10-K for the fiscal year ended December 31, 1998).
10.11*	—	Form of Stock Option Secured Promissory Note and Pledge Agreement among Williams and certain employees, officers and non-employee directors (filed as Exhibit 10(iii)(m) to our Form 10-K for the fiscal year ended December 31, 1998).
10.12*	—	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).
10.13*	—	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).
10.14*	—	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).
10.15*	—	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).
10.16*	—	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).
10.17*	—	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 4.1 to our Form S-8 filed August 1, 2001).
10.18*	—	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).
10.19*	—	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).
10.20*	—	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).
10.21	—	The Williams Companies, Inc. Severance Pay Plan as Amended and Restated Effective October 28, 2003.
10.22	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated October 28, 2003.

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Exhibit No.		Description
10.23	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated June 1, 2004.
10.24	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated January 1, 2005.
10.25*	—	U.S. $500,000,000 Term Loan Agreement among Williams Production Holdings LLC, Williams Production RMT Company, as Borrower, the Several Lenders from time to time parties thereto, Lehman Brothers Inc. and Banc of America Securities LLC as Joint Lead Arrangers, Citigroup USA, Inc. and JPMorgan Chase Bank, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and Lehman Commercial Paper Inc., as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.1 to our Form 10-Q filed August 12, 2003).
10.26*	—	The First Amendment to the Term Loan Agreement dated February 25, 2004, between Williams Production Holdings, LLC, Williams Production RMT Company, as Borrower, the several financial institutions as lenders and Lehman Commercial Paper Inc., as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.3 to our Form 10-Q filed May 6, 2004).
10.27*	—	Guarantee and Collateral Agreement made by Williams Production Holdings LLC, Williams Production RMT Company and certain of its Subsidiaries in favor of Lehman Commercial Paper Inc. as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.2 to our Form 10-Q filed August 12, 2003).
10.28*	—	U.S. $1,000,000,000 Credit Agreement dated as of May 3, 2004, among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipeline Corporation, as Borrowers, Citicorp USA, Inc., as Administrative Agent and Collateral Agent, Citibank, N.A. and Bank of America, N.A., Collateral Agent, Citibank, N.A. and Bank of America, N.A., as Issuing Banks, the banks named therein as Banks, Bank of America, N.A., as Syndication Agent, JPMorgan Chase Bank, The Bank of Nova Scotia, The Royal Bank of Scotland plc as Co-Documentation Agents, Citigroup Global Markets Inc. and Banc of America Securities LLC as Joint Lead Arrangers and Co-Book Runners (filed as Exhibit 10.4 to our Form 10-Q filed May 6, 2004).
10.29*	—	Letter of Credit Commitment Increase Agreement dated August 4, 2004, by and among The Williams Companies, Inc., Citicorp USA in its capacity as Agent under the Credit Agreement dated as of May 3, 2004 among the Borrower, Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, the Agent, the Collateral Agent, the Banks and Issuing Banks party thereto and Citibank, N.A. and Bank of America, N.A. (filed as Exhibit 10.1 to our Form 10-Q filed November 4, 2004).
10.30*	—	Revolving Credit Commitment Increase Agreement dated August 4, 2004, by and among The Williams Companies, Inc., Citicorp USA in its capacity as Agent under the Credit Agreement dated as of May 3, 2004 among the Borrower, Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, the Agent, the Collateral Agent and the Banks and Issuing Banks party thereto, the Issuing Banks and Citicorp USA, Inc. (filed as Exhibit 10.2 to our Form 10-Q filed November 4, 2004).
10.31*	—	U.S. $1,275,000,000 Amended and Restated Credit Agreement Dated as of May 20, 2005 among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, Williams Partners L.P., as Borrowers, Citicorp USA, Inc., As Administrative Agent and Collateral Agent, Citibank, N.A. Bank of America, N.A. as Issuing Banks and The Banks Named Herein as Banks (filed as Exhibit 1.1 to our Form 8-K filed May 26, 2005).
10.32*	—	Amendment Agreement dated as of October 19, 2004 among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipeline Corporation, as Borrowers, the banks, financial institutions and other institutional lenders that are parties to the Credit Agreement dated as of May 3, 2004 among the Borrowers, the Banks, Citicorp USA, Inc., as agent and Citibank, N.A. and Bank of America, N.A., as issuers of letters of credit under the Credit Agreement, the Agent and the Issuing Banks (filed as Exhibit 10.29 to our Form 10-K filed March 11, 2005).
10.33*	—	Western Midstream Security Agreement dated as of May 3, 2004, among Williams Gas Processing Company, Williams Field Services Company, Williams Gas Processing — Wamsutter Company as Grantors, in favor of Citicorp USA, Inc. as Collateral Agents (filed as Exhibit 10.5 to our Form 10-Q filed May 6, 2004).
10.34*	—	Pledge Agreement dated as of May 3, 2004, by Williams Field Services Group, Inc. in favor of Citicorp USA, Inc. as Collateral Agent (filed as Exhibit 10.6 to our Form 10-Q filed May 6, 2004).

Exhibit No.		Description
10.35*	—	Western Midstream Guaranty by Williams Gas Processing Company, Williams Field Services Company, Williams Gas Processing — Wamsutter Company as Guarantors in favor of Citicorp USA, Inc. as Collateral Agent (filed as Exhibit 10.7 to our Form 10-Q filed May 6, 2004).
10.36*	—	Pipeline Holdco Guaranty by Williams Gas Pipeline Company, LLC as Guarantor in favor of Citicorp USA, Inc. as Collateral Agent (filed as Exhibit 10.8 to our Form 10-Q filed May 6, 2004).
10.37*	—	Amended and Restated U.S. $400,000,000 Five Year Credit Agreement dated April 14, 2004 and amended 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 10.1 to our Form 8-K filed on January 26, 2005).
10.38*	—	Amended and Restated U.S. $100,000,000 Five Year Credit Agreement dated April 26, 2004 and amended 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 10.2 to our Form 8-K filed on January 26, 2005).
10.39*	—	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).
10.40*	—	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).
10.41*	—	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 10.3 to our Form 8-K filed on September 26, 2005).
10.42*	—	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 10.3 to our Form 8-K filed on September 26, 2005).
10.43*	—	New Omnibus Agreement among WEG Acquisitions, L.P., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and The Williams Companies, Inc. dated as of June 17, 2003 (filed as Exhibit 10.9 to our Form 10-Q filed August 12, 2003).
10.44*	—	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).
10.45*	—	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).
10.46*	—	Sale Agreement Relating to the Sale of the Interest of Williams Energy (Canada), Inc. in the Cochrane, Empress II and Empress V Straddle Plants dated as of July 8, 2004 between Williams Energy (Canada), Inc. and 1024234 Alberta Ltd. (filed as Exhibit 10.7 to our Form 10-Q filed August 5, 2004).
10.47*	—	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).
10.48*	—	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).
10.49*	—	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).
10.50*	—	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).

Exhibit No.		Description
10.51*	—	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).
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 2006 (to be filed with the Securities and Exchange Commission on or before April 10, 2006).
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.

Exhibit 3.2
Effective November 17, 2005

BY-LAWS
OF
THE WILLIAMS COMPANIES, INC.
(hereinafter called the "Company")

ARTICLE I

OFFICES

Section 1. Registered Office. The registered office of the Company shall be in the City of Wilmington, County of New Castle, State of Delaware.

Section 2. Other Offices. The Company may also have offices at such other places both within and without the State of Delaware as the Board of Directors may from time to time determine.

ARTICLE II

MEETINGS OF STOCKHOLDERS

Section 1. Place of Meetings. Meetings of the stockholders for the election of Directors or for any other purpose shall be held at such time and place, either within or without the State of Delaware, as shall be designated from time to time by the Board of Directors and stated in the notice of the meeting or in a duly executed waiver of notice thereof.

Section 2. Annual Meetings. The Annual Meetings of the Stockholders shall be held on such date and at such time as shall be designated from time to time by the Board of Directors and stated in the notice of the meetings, at which meetings the stockholders shall elect by a plurality vote the Directors to be elected at such meetings, and transact such other business as may properly be brought before the meetings. Written notice of the Annual Meeting stating the place, date and hour of the meeting shall be given to each stockholder entitled to vote at such meeting not less than ten nor more than sixty days before the date of the meeting.

Section 3. Special Meetings. Unless otherwise prescribed by law or by the Restated Certificate of Incorporation, Special Meetings of Stockholders, for any purpose or purposes, may be called by either the Chairman of the Board, if one has been elected, or the President, and shall be called by either such officer or the Secretary at the request in writing of a majority of the Board of Directors. Such request shall state the purpose or purposes of the proposed meeting. Written notice of a Special Meeting stating the place, date and hour of the meeting and the purpose or purposes for which the meeting is called shall be given not less than ten nor more than sixty days before the date of the meeting to each stockholder entitled to vote at such meeting.

Section 4. Quorum. Except as otherwise provided by law or by the Restated Certificate of Incorporation, the holders of a majority of the capital stock issued and outstanding and entitled to vote thereat, present in person or represented by proxy, shall constitute a quorum at all meetings of the stockholders for the transaction of business. If, however, such quorum shall not be present or represented by proxy at any meeting of the stockholders, the stockholders entitled to vote thereat, present in person or represented by proxy, shall have power to adjourn the meeting from time to time, without notice other than announcement at the meeting, until a quorum shall be present or represented. At such adjourned meeting at which a quorum shall be present or represented by proxy, any business may be transacted which might have been transacted at the meeting as originally noticed. If the adjournment is for more than thirty days, or if after the adjournment a new record date is fixed for the adjourned meeting, a written notice of the adjourned meeting shall be given to each stockholder entitled to vote at the meeting.

Section 5. Voting. At each meeting of stockholders held for any purpose, each stockholder of record of Common Stock entitled to vote thereat shall be entitled to one vote for every share of such stock standing in such stockholder's name on the books of the Company on the date determined in accordance with Section 5 of Article V of these By-laws, and each stockholder of record of Preferred Stock entitled to vote thereat shall be entitled to the vote as set forth in the resolution or resolutions of the Board of Directors providing for such series for each share of Preferred Stock standing in such stockholder's name on the books of the Company on the date determined in accordance with Section 5 of Article V of these By-laws. On any matter on which the holders of the Preferred Stock or any series thereof shall be entitled to vote separately as a class or series, they shall be entitled to one vote for each share held.

Each stockholder entitled to vote at any meeting of stockholders may authorize not in excess of three persons to act for such stockholder by a proxy signed by such stockholder or such stockholder's attorney-in-fact. Any such proxy shall be delivered to the secretary of such meeting at or prior to the time designated for holding such meeting, but in any event not later than the time designated in the order of business for so delivering such proxies. No such proxy shall be voted or acted upon after three years from its date, unless the proxy provides for a longer period. Except as otherwise provided by law or by the Restated Certificate of Incorporation, at each meeting of the stockholders, all corporate actions to be taken by vote of the stockholders shall be authorized by a majority of the votes cast by the stockholders entitled to vote thereon, present in person or represented by proxy, and where a separate vote by class is required, a majority of the votes cast by the stockholders of such class, present in person or represented by proxy, shall be the act of such class.

Unless required by law or determined by the chairman of the meeting to be advisable, the vote on any matter, including the election of Directors, need not be by written ballot. In the case of a vote by written ballot, each ballot shall be signed by the stockholder voting, or by such stockholder's proxy, and shall state the number of shares voted.

Section 6. List of Stockholders Entitled to Vote. The officer of the Company who has charge of the stock ledger of the Company shall prepare and make, at least ten days before every meeting of stockholders, a complete list of the stockholders entitled to vote at the meeting, arranged in alphabetical order, and showing the address of each stockholder and the number of shares registered in the name of each stockholder. Such list shall be open to the examination of any stockholder or person representing a stockholder by proxy, for any purpose germane to the meeting, during ordinary business hours, for a period of at least ten days prior to the meeting, either at a place within the city where the meeting is to be held, which place shall be specified in the notice of the meeting, or, if not so specified, at the place where the meeting is to be held. The list shall also be produced and kept at the time and place of the meeting during the whole time thereof, and may be inspected by any stockholder of the Company who is present.

Section 7. Stock Ledger. The stock ledger of the Company shall be the only evidence as to who are the stockholders entitled to examine the stock ledger, the list required by Section 6 of this Article II or the books of the Company, or to vote in person or by proxy at any meeting of stockholders.

Section 8. Nature of Business at Meetings of Stockholders. No business may be transacted at an Annual Meeting of Stockholders, other than business that is either (a) specified in the notice of meeting (or any supplement thereto) given by or at the direction of the Board of Directors (or any duly authorized committee thereof), (b) otherwise properly brought before the annual meeting by or at the direction of the Board of Directors (or any duly authorized committee thereof) or (c) otherwise properly brought before the annual meeting by any Stockholder of the Company (i) who is a Stockholder of record on the date of the giving of the notice provided for in this Section 8 and on the record date for the determination of Stockholders entitled to vote at such annual meeting and (ii) who complies with the notice procedures set forth in this Section 8.

In addition to any other applicable requirements, for business to be properly brought before an annual meeting by a Stockholder, such Stockholder must have given timely notice thereof in proper written form to the Secretary of the Company.

To be timely, a Stockholder’s notice to the Secretary must be delivered to or mailed and received at the principal executive offices of the Company not less than ninety (90) days nor more than one hundred and twenty (120) days prior to the anniversary date of the immediately preceding Annual Meeting of Stockholders; provided, however, that in the event that the Annual Meeting is called for a date that is not within thirty (30) days before or after such anniversary date, notice by the Stockholder in order to be timely must be so received not later than the close of business on the tenth (10th) day following the day on which such notice of the date of the Annual Meeting was mailed or such public disclosure of the date of the Annual Meeting was made, whichever first occurs.

To be in proper written form, a Stockholder’s notice to the Secretary must set forth as to each matter such Stockholder proposes to bring before the Annual Meeting (i) a brief description of the business desired to be brought before the Annual Meeting and the reasons for conducting such business at the Annual Meeting, (ii) the name and record address of such Stockholder, (iii) the class or series and number of shares of capital stock of the Company which are owned beneficially or of record by such Stockholder, (iv) a description of all arrangements or understandings between such Stockholder and any other person or persons (including their names) in connection with the proposal of such business by such Stockholder and any material interest of such Stockholder in such business and (v) a representation that such Stockholder intends to appear in person or by proxy at the Annual Meeting to bring such business before the meeting.

No business shall be conducted at the Annual meeting of Stockholders except business brought before the Annual Meeting in accordance with the procedures set forth in this Section 8; provided, however, that, once business has been properly brought before the Annual Meeting in accordance with such procedures, nothing in this Section 8 shall be deemed to preclude discussion by any Stockholder of any such business. If the Chairman of an Annual Meeting determines that business was not properly brought before the Annual Meeting in accordance with the foregoing procedures, the Chairman shall declare to the meeting that the business was not properly brought before the meeting and such business shall not be transacted.

ARTICLE III

DIRECTORS

Section 1. Number, Nomination, and Election of Directors. The number of Directors constituting the Board of Directors shall be no more than seventeen nor less than five, the precise number within such limitations to be fixed by resolution of the Board of Directors from time to time. Except as provided in Section 2 of this Article III, the Directors to be elected at each Annual Meeting of Stockholders shall be elected by a plurality of the votes cast at such Annual Meeting of Stockholders, and each Director so elected shall hold office until the third Annual Meeting of Stockholders following such election and until a successor is duly elected and qualified, or until earlier resignation or removal. Any Director may resign at any time upon notice to the Company. Directors need not be stockholders.

Notwithstanding the foregoing, whenever the holders of any Preferred Stock, as may at any time be provided in the Restated Certificate of Incorporation or in any resolution or resolutions of the Board of Directors establishing any such Preferred Stock, shall have the right, voting as a class or as classes, to elect Directors at any Annual or Special Meeting of Stockholders, the then authorized number of Directors of the Company may be increased by such number as may therein be provided, and at such meeting the holders of such Preferred Stock shall be entitled to elect the additional Directors as therein provided. Any Directors so elected, unless so reelected at the Annual Meeting of Stockholders or Special Meeting held in place thereof, next succeeding the time when the holders of any such Preferred Stock became entitled to elect Directors as above provided, shall not hold office beyond such Annual or Special Meeting. Any such provision for election of

Directors by holders of the Preferred Stock shall apply notwithstanding the maximum number of Directors set forth in the provisions hereinabove.

Only persons who are nominated in accordance with the following procedures shall be eligible for election as Directors of the Company, except as may be otherwise provided in the Restated Certificate of Incorporation with respect to the right of holders of preferred stock of the Company to nominate and elect a specified number of Directors in certain circumstances. Nominations of persons for election to the Board of Directors may be made at any Annual Meeting of Stockholders, or at any Special Meeting of Stockholders called for the purpose of electing Directors, (a) by or at the direction of the Board of Directors (or any duly authorized committee thereof) or (b) by any Stockholder of the Company (i) who is a Stockholder of record on the date of the giving of the notice provided for in this Section 9 and on the record date for the determination of Stockholders entitled to vote at such meeting and (ii) who complies with the notice procedures set forth in this Section 9.

In addition to any other applicable requirements, for a nomination to be made by a Stockholder, such Stockholder must have given timely notice thereof in proper written form to the Secretary of the Company.

To be timely, a Stockholder's notice to the Secretary must be delivered to or mailed and received at the principal executive offices of the Company (a) in the case of an Annual Meeting, not less than ninety (90) days nor more than one hundred and twenty (120) days prior to the anniversary date of the immediately preceding Annual Meeting of Stockholders; provide however, that in the event that the Annual Meeting is called for a date that is not within thirty (30) days before or after such anniversary date, notice by the Stockholder in order to be timely must be so received not later than the close of business on the tenth (10th) day following the day on which such notice of the date of the Annual Meeting was mailed or such public disclosure of the date of the Annual Meeting was made, whichever first occurs; and (b) in the case of a Special Meeting of Stockholders called for the purpose of electing Directors, not later than the close of business on the tenth (10th) day following the day on which notice of the date of the Special meeting was mailed or public disclosure of the date of the Special meeting was made, whichever first occurs.

To be in proper written form, a Stockholder's notice to the Secretary must set forth (a) as to each person whom the Stockholder proposes to nominate for election as a Director (i) the name, age, business address and residence address of the person, (ii) the principal occupation or employment of the person, (iii) the class or series and number of shares of capital stock of the Company which are owned beneficially or of record by the person and (iv) any other information relating to the person that would be required to be disclosed in a proxy statement or other filings required to be made in connection with solicitations of proxies for election of Directors pursuant to Section 14 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the rules and regulations promulgated thereunder; and (b) as to the Stockholder giving the notice (i) the name and record address of such Stockholder, (ii) the class or series and number of shares of capital stock of the Company which are owned beneficially or of record by such Stockholder, (iii) a description of all arrangements or understandings between such Stockholder and each proposed nominee and any other person or persons (including their names) pursuant to which the nominations are to be made by such Stockholder, (iv) a representation that such Stockholder intends to appear in person or by proxy at the meeting to nominate the persons named in its notice and (v) any other information relating to such Stockholder that would be required to be disclosed in a proxy statement or other filings required to be made in connection with solicitations of proxies for election of Directors pursuant to Section 14 of the Exchange Act and the rules and regulations promulgated thereunder. Such notice must be accompanied by a written consent of each proposed nominee to being named as a nominee and to serve as a Director if elected.

No person shall be eligible for election as a Director of the Company unless nominated in accordance with the procedures set forth in this Section 9. If the Chairman of the meeting determines that a nomination was not made in accordance with the foregoing procedures, the Chairman shall declare to the meeting that the nomination was defective and such defective nomination shall be disregarded.

Section 2. Vacancies. Subject to the provisions of the Restated Certificate of Incorporation, vacancies and newly created directorships resulting from any increase in the authorized number of Directors may be filled by a majority of the Directors then in office, though less than a quorum, or by a sole remaining Director, and the Directors so chosen shall hold office for a term that shall coincide with the unexpired portion of the term of that directorship, and until their successors are duly elected and qualified, or until their earlier resignation or removal.

Section 3. Duties and Powers. The business of the Company shall be managed by or under the direction of the Board of Directors which may exercise all such powers of the Company and do all such lawful acts and things as are not by statute or by the Restated Certificate of Incorporation or by these By-laws directed or required to be exercised or done by the stockholders.

Section 4. Meetings. The Board of Directors of the Company may hold meetings, both regular and special, within or without the State of Delaware. Regular meetings of the Board of Directors may be held without notice at such time and at such place as may from time to time be determined by the Board of Directors. Special meetings of the Board of Directors may be called by the Chairman of the Board, if one has been elected, or by the President or any three Directors. Notice thereof stating the place, date and hour of the meeting shall be given to each Director either by mail not less than forty-eight (48) hours before the date of the meeting, by telephone or telegram on twenty-four (24) hours notice, or on such shorter notice as the person or persons calling such meeting may deem necessary or appropriate in the circumstances.

Section 5. Quorum. Except as may be otherwise specifically provided by law, the Restated Certificate of Incorporation or these By-laws, at all meetings of the Board of Directors, a majority of the entire Board of Directors shall constitute a quorum for the transaction of business and the act of a majority of the Directors present at any meeting at which there is a quorum shall be the act of the Board of Directors. If a quorum shall not be present at any meeting of the Board of Directors, a majority of the Directors present thereat may adjourn the meeting from time to time, without notice other than announcement at the meeting, until a quorum shall be present.

Section 6. Actions of the Board. Unless otherwise provided by the Restated Certificate of Incorporation or these By-laws, any action required or permitted to be taken at any meeting of the Board of Directors or of any committee thereof may be taken without a meeting, if all the members of the Board of Directors or committee, as the case may be, consent thereto in writing, and the writing or writings are filed with the minutes of the proceedings of the Board of Directors or committee.

Section 7. Meetings by Means of Conference Telephone. Unless otherwise provided by the Restated Certificate of Incorporation or these By-laws, members of the Board of Directors, or any committee designated by the Board of Directors, may participate in a meeting of the Board of Directors or such committee by means of a conference telephone or similar communications equipment by means of which all persons participating in the meeting can hear each other, and participation in a meeting pursuant to this Section 7 shall constitute presence in person at such meeting.

Section 8. Committees. The Board of Directors may designate one or more committees, each committee to consist of one or more of the Directors. The Board of Directors may designate one or more Directors as alternate members of any committee, who may replace any absent or disqualified member at any meeting of any such committee. In the absence or disqualification of a member of a committee, the member or members present at any meeting and not disqualified from voting, whether or not a quorum, may unanimously appoint another member of the Board of Directors to act at the meeting in the place of any absent or disqualified member. Any such committee, to the extent provided in the resolution of the Board of Directors, or in the By-laws of the Company, shall have and may exercise all the powers and authority of the Board of Directors in the management of the business and affairs of the Company, and may authorize the seal of the Company to be affixed to all papers which may require it; but no such committee shall have the power or authority in reference to the following matters: (i) approving or adopting, or recommending to the stockholders, any action or matter expressly required by Delaware law to be submitted to stockholders for approval; or (ii) adopting, amending or repealing any By-law of the Company. Each committee shall keep regular minutes and report to the Board of Directors when required.

Section 9. Compensation. The Directors may be paid their expenses, if any, of attendance at each meeting of the Board of Directors and such compensation for serving as a Director and attending each meeting of the Board of Directors as may be fixed from time to time by resolution of the Board. No such payment shall preclude any Director from serving the Company in any other capacity and receiving compensation therefor. Members of special or standing committees may also be paid such compensation for committee service or for attending committee meetings as the Board may establish from time to time.

Section 10. Retirement Policy. The normal retirement date for a Director shall be at the first Annual Meeting of Stockholders of the Company following the Director’s 72nd birthday, and except as provided in this Section 10, no one shall serve as a Director beyond this normal retirement date. A Director may be nominated (and elected) to serve as a Director after the normal retirement date provided that: (i) the Director expresses to the Board of Directors a willingness to serve as a Director after the normal retirement date; (ii) at the time of being a nominee for a term of office that would extend beyond the normal retirement date, such person was a Director and was so elected by the stockholders of the Company; (iii) the Director's nomination as a nominee for the term extending beyond the normal retirement date was by majority vote of all Directors then in office; (iv) the stockholders of the Company were advised fully regarding the Director's intent to serve on the Board after the normal retirement date; and (v) the Director was thereafter elected a Director by the stockholders in accordance with the Restated Certificate of Incorporation and By-laws of the Company. Nothing herein shall be construed to create a right of any Director to be nominated for reelection to the Board or as a limitation upon the right of the Board of Directors not to nominate any Director for such reelection.

ARTICLE IV

OFFICERS

Section 1. General. The officers shall be elected by the Board of Directors and shall include a President, a Secretary and a Treasurer and, at the discretion of the Board of Directors, may include a Chairman of the Board, one or more Vice Presidents and such other officers as the Board of Directors may from time to time deem necessary or appropriate. Any number of offices may be held by the same person, unless otherwise prohibited by law, the Restated Certificate of Incorporation or these By-laws. The officers need not be stockholders nor, except in the case of the Chairman of the Board, need such officers be Directors.

Section 2. Election. The Board of Directors shall elect the officers of the Company who shall hold their offices for such terms and shall exercise such powers and perform such duties as shall be determined from time to time by the Board of Directors; and all officers shall hold office until their successors are chosen and qualified, or until their death, resignation or removal. Any officer elected by the Board of Directors may be removed at any time by the affirmative vote of a majority of the Board of Directors. Any vacancy occurring in any office shall be filled by the Board of Directors.

Section 3. Voting Securities Owned by the Company. Powers of attorney, proxies, waivers of notice of meeting, consents and other instruments relating to securities owned by the Company may be executed in the name of and on behalf of the Company by the Chief Executive Officer, any Vice President or the Secretary, and any such officer may in the name of and on behalf of the Company, take all such action as any such officer may deem advisable to vote in person or by proxy at any meeting of security holders of any corporation in which the Company may own securities and at any such meeting shall possess ownership of such securities and which, as the owner thereof, the Company might have exercised and possessed if present. The Board of Directors may, by resolution, from time to time confer like powers upon any other person or persons.

Section 4. Chief Executive Officer. If no Chairman of the Board has been elected, the President shall be the Chief Executive Officer. If a person has been elected as both Chairman of the Board and President, that person shall be the Chief Executive Officer. Otherwise, if a Chairman of the Board has been elected, the Board of Directors shall designate either the Chairman of the Board or the President as Chief Executive Officer. Subject to the directions of the Board of Directors or any duly authorized committee of Directors, the Chief Executive Officer shall direct the policy of the Company and shall have general direction of the Company's business, affairs and property and over its several officers, in addition to his duties set forth in Section 5 or 6 of this Article IV, as the case may be.

Section 5. Chairman of the Board. If one has been elected, the Chairman of the Board shall, if present, preside at all meetings of the Board of Directors and of the stockholders. The Chairman of the Board may, with the Treasurer or the Secretary, or an Assistant Treasurer or an Assistant Secretary, sign certificates for stock of the Company and any other documents, of whatever nature, in the name of the Company, except in cases where the signing and execution thereof shall be expressly delegated by the Board of Directors or by a duly authorized committee of Directors, or by these By-laws to some other officer or agent of the Company, or shall be required by law otherwise to be signed or executed and shall perform such other duties as may from time to time be assigned by the Board of Directors or by any duly authorized committee of Directors.

Section 6. President. The President, unless he is serving as Chief Executive Officer, shall be responsible to the Chairman of the Board. During the absence or disability of the Chairman of the Board, or if one shall not have been elected, the President shall exercise all the powers and discharge all the duties of the Chairman of the Board. The President may, with the Treasurer or the Secretary, or an Assistant Treasurer or an Assistant Secretary, sign certificates for stock of the Company and any other documents, of whatever nature, in the name of the Company, except in cases where the signing and execution thereof shall be expressly delegated by the Board of Directors or by a duly authorized committee of Directors, or by these By-laws, to some other officer or agent of the Company, or shall be required by law otherwise to be signed or executed and shall perform such other duties as may from time to time be assigned by the Board of Directors or by any duly authorized committee of Directors.

Section 7. Vice Presidents. In the absence of the President or in the event of inability or refusal of the President to perform the duties of his office, the Vice Presidents (including the Vice President designated as the Chief Financial Officer), if any have been elected, in the order designated by the Board of Directors or, in the absence of such designation, in the order of seniority in office, shall perform the duties and possess the authority and powers of the President. Any Vice President may also sign and execute in the name of the Company deeds, mortgages, bonds, contracts and other instruments, except in cases where the signing and execution thereof shall be expressly delegated by the Board of Directors or by a duly authorized committee of Directors, or by these By-laws, to some other officer or agent of the Company, or shall be required by law otherwise to be signed or executed. Each Vice President shall perform such other duties and have such other powers as the Board of Directors from time to time may prescribe.

Section 8. Secretary. The Secretary shall attend all meetings of the Board of Directors and all meetings of stockholders and record all of the proceedings thereat in a book or books to be kept for that purpose; the Secretary shall also perform, or cause to be performed, like duties for the standing committees when required. The Secretary shall give, or cause to be given, notice of all meetings of the stockholders and special meetings of the Board of Directors, and shall perform such other duties as may be prescribed by the Board of Directors or the Chief Executive Officer. If the Secretary shall be unable or shall refuse to cause notice to be given of all meetings of the stockholders and special meetings of the Board of Directors, and if there be no Assistant Secretary, then either the Board of Directors, the Chairman of the Board, if one has been elected, or the President may choose another officer to cause such notice to be given. The Secretary shall have custody of the seal of the Company and the Secretary or any Assistant Secretary, if there be one, shall have authority to affix the same to any instrument requiring it and when so affixed, it may be attested by the signature of the Secretary or by the signature of any such Assistant Secretary. The Board of Directors may give general authority to any other officer to affix the seal of the Company and to attest the affixing by such officers a signature. The Secretary shall see that all books, reports, statements, certificates and other documents and records required by law to be kept or filed are properly kept or filed, as the case may be.

Section 9. Treasurer. The Treasurer shall have the custody of the corporate funds and securities and shall keep full and accurate accounts of receipts and disbursements in books belonging to the Company and shall deposit all moneys and other valuable effects in the name and to the credit of the Company in such depositories as may be designated by the Board of Directors. The Treasurer shall disburse the funds of the Company as may be ordered by the Board of Directors, taking proper vouchers for such disbursements, and shall render to the Board of Directors, at its regular meetings, or when the Board of Directors so requires, an account of all transactions of the Treasurer and of the financial condition of the Company.

Section 10. Assistant Secretaries. Except as may be otherwise provided in these By-laws, Assistant Secretaries, if there be any, shall perform such duties and have such powers as from time to time may be assigned to them by the Board of Directors, the Chief Executive Officer, any Vice President or the Secretary, and in the absence of the Secretary or in the event of the disability or refusal of the Secretary to act, shall perform the duties of the Secretary, and when so acting, shall have all the powers of and be subject to all the restrictions upon the Secretary.

Section 11. Assistant Treasurers. Assistant Treasurers, if there be any, shall perform such duties and have such powers as from time to time may be assigned to them by the Board of Directors, the Chief Executive Officer, any Vice President or the Treasurer, and in the absence of the Treasurer or in the event of the disability or refusal to act of the Treasurer, shall perform the duties of the Treasurer, and when so acting, shall have all the powers of and be subject to all the restrictions upon the Treasurer.

Section 12. Other Officers. Such other officers as the Board of Directors may choose shall perform such duties and have such powers as from time to time may be assigned to them by the Board of Directors.

ARTICLE V

STOCK

Section 1. Form of Certificates. Every holder of stock in the Company shall be entitled to have a certificate signed in the name of the Company (i) by the Chairman of the Board, if one has been elected, or the President; and (ii) by the Secretary or an Assistant Secretary of the Company, certifying the number of shares owned.

Section 2. Signatures. Where a certificate is countersigned by (i) a transfer agent other than the Company or its employee, or (ii) a registrar other than the Company or its employee, any other signature on the certificate may be a facsimile. In case any officer, transfer agent or registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, transfer agent or registrar before such certificate is issued, the certificate may be issued by the Company with the same effect as if such officer or entity were an officer, transfer agent or registrar at the date of issue.

Section 3. Lost Certificates. The Board of Directors may direct a new certificate to be issued in place of any certificate theretofore issued by the Company alleged to have been lost, stolen or destroyed, upon the making of an affidavit of that fact by the person claiming the certificate of stock to be lost, stolen or destroyed. When authorizing such issue of a new certificate, the Board of Directors may, in its discretion and as a condition precedent to the issuance thereof, require the owner of such lost, stolen or destroyed certificate, or such owner's legal representative, to advertise the same in such manner as the Board of Directors shall require and/or to give the Company a bond in such sum as it may direct as indemnity against any claim that may be made against the Company and its transfer agents and registrars with respect to the certificate alleged to have been lost, stolen or destroyed.

Section 4. Transfers. Stock of the Company shall be transferable in the manner prescribed by law and in these By-laws. Transfers of stock shall be made on the books of the Company only by the person named in the certificate or by such person's attorney lawfully constituted in writing and filed with the Secretary of the Company, or a transfer agent for such stock, if any, and upon the surrender of the certificate therefor, which shall be canceled before a new certificate shall be issued.

Section 5. Record Date. In order that the Company may determine the stockholders entitled to notice of or to vote at any meeting of stockholders or any adjournment thereof, or entitled to receive payment of any dividend or other distribution or allotment of any rights, or entitled to exercise any rights in respect of any change, conversion or exchange of stock, or for the purpose of any other lawful action, the Board of Directors may fix, in advance, a record date, which shall not be more than sixty days nor less than ten days before the date of such meeting, nor more than sixty days prior to any other action for which a record date is required. A determination of stockholders of record entitled to notice of or to vote at a meeting of stockholders shall apply to any adjournment of the meeting; provided, however, that the Board of Directors may fix a new record date for the adjourned meeting.

ARTICLE VI

NOTICES

Section 1. Notices. Whenever written notice is required by law, the Restated Certificate of Incorporation or these By-laws, to be given to any Director, member of a committee or stockholder, such notice may be given by mail, addressed to such Director, member of a committee or stockholder, at such address as appears on the records of the Company, with postage thereon prepaid, and such notice shall be deemed to be given at the time when the same shall be deposited in the United States mail. Written notice may also be given personally or by telegram, telex or cable.

Section 2. Waivers of Notice. Whenever any notice is required by law, the Restated Certificate of Incorporation or these By-laws, to be given to any Director, member of a committee or stockholder, a waiver thereof in writing, signed by the person or persons entitled to said notice, whether before or after the time stated therein, shall be deemed equivalent thereto.

ARTICLE VII

GENERAL PROVISIONS

Section 1. Dividends. Dividends upon the capital stock of the Company, subject to the provisions of the Restated Certificate of Incorporation, if any, may be declared by the Board of Directors at any regular or special meeting, and may be paid in cash, in property or in shares of the capital stock. Before payment of any dividend, there may be set aside out of any funds of the Company available for dividends such sum or sums as the Board of Directors from time to time, in its absolute discretion, deems proper as a reserve or reserves to meet contingencies, or for equalizing dividends, or for repairing or maintaining any property of the Company, or for any proper purpose, and the Board of Directors may modify or abolish any such reserve.

Section 2. Fiscal Year. The fiscal year of the Company shall be fixed by resolution of the Board of Directors.

Section 3. Corporate Seal. The corporate seal shall have inscribed thereon the name of the Company, the year of its organization and the words "Corporate Seal, Delaware." The seal may be used by causing it or a facsimile thereof to be impressed, affixed, reproduced or otherwise.

Section 4. By-laws Subject to Law and Restated Certificate of Incorporation of the Company. Each provision of these By-laws is subject to any contrary provision of the Restated Certificate of Incorporation of the Company or of an applicable law as from time to time in effect, and to the extent any such provision is inconsistent therewith, such provision shall be superseded thereby for as long as such inconsistency shall exist, but for all other purposes these By-laws shall continue in full force and effect.

ARTICLE VIII

INDEMNIFICATION

Section 1. Right to Indemnification. Each person (hereinafter referred to as an "indemnitee") who was or is made a party or is threatened to be made a party to or is otherwise involved in any action, suit, arbitration, alternative dispute mechanism, inquiry, administrative or legislative hearing, investigation or any other actual, threatened or completed proceeding, including any and all appeals, whether civil, criminal, administrative or investigative (hereinafter a "proceeding"), by reason of the fact that he or she (a) is or was an employee providing service to an employee benefit plan in which the Company or any of its subsidiaries or affiliates participates or is a participating company or (b) is or was a director or an officer of the Company or is or was serving at the request of the Company as a director or officer (including elected or appointed positions that are equivalent to director or officer) of another corporation, partnership, joint venture, trust or other enterprise, whether the basis of such proceeding is alleged action in an official capacity as a director or officer (or equivalent) or in any other capacity while serving as a director or officer (or equivalent), shall be indemnified and held harmless by the Company to the fullest extent authorized by the Delaware General Corporation Law ("DGCL"), as the same exists or may hereafter be amended, against all expense, liability and loss (including attorneys' fees, judgments, fines, ERISA excise taxes or penalties and amounts paid in settlement) reasonably incurred or suffered by such indemnitee in connection therewith; provided, however, that, except as provided in Section 3 of this Article VIII with respect to proceedings to enforce rights to indemnification, the Company shall indemnify any such indemnitee in connection with a proceeding (or part thereof) initiated by such indemnitee only if such proceeding (or part thereof) was authorized or ratified by the Board of Directors of the Company.

Section 2. Advancement of Expenses.

(a) In addition to the right to indemnification conferred in Section 1 of this Article VIII, each director, the Chief Executive Officer, and the Chief Financial Officer of the Company shall, to the fullest extent not prohibited by law, also have the right to be paid by the Company the expenses (including attorneys' fees) incurred in defending any such proceeding in advance of its final disposition (hereinafter an "advancement of expenses"); provided, however, that, if the DGCL requires, an advancement of expenses incurred by an indemnitee in his or her capacity as a director, Chief Executive Officer or Chief Financial Officer (and not in any other capacity in which service was or is rendered by such indemnitee, including, without limitation, service to an employee benefit plan) shall be made only upon delivery to the Company of an undertaking (hereinafter an "undertaking"), by or on behalf of such indemnitee, to repay all amounts so advanced if it shall ultimately be determined by final judicial decision from which there is no further right to appeal (hereinafter a "final adjudication") that such indemnitee is not entitled to be indemnified for such expenses under this Section 2(a) of this Article VIII or otherwise.

(b) In addition to the right to indemnification conferred in Section 1 of this Article VIII and except for the indemnitees covered under Section 2(a) above, any person entitled to indemnification in Section 1 may to the extent authorized from time to time by the Board of Directors, be paid an advancement of expenses, provided, however, that if the DGCL requires an advancement of expenses incurred by an indemnitee in his or her capacity as an officer (and not in any other capacity in which service was or is rendered by such indemnitee, including, without limitation, service to an employee benefit plan) shall be made only upon delivery of an undertaking, by or on behalf of such indemnitee, to repay all amounts so advanced if it shall ultimately be determined by final adjudication that such indemnitee is not entitled to be indemnified for such expenses under this Section 2(b) of this Article VIII or otherwise.

Section 3. Right of Indemnitee to Bring Suit. If a claim under Section 1 or 2 of this Article VIII is not paid in full by the Company within 60 days after a written claim has been received by the Company, except in the case of a claim for an advancement of expenses, in which case the applicable period shall be 20 days, the indemnitee may at any time thereafter bring suit against the Company in a court of competent jurisdiction in the State of Delaware to recover the unpaid amount of the claim. If successful in whole or in part in any such suit, or in a suit brought by the Company to recover an advancement of expenses pursuant to the terms of an undertaking, the indemnitee shall be entitled to be paid also the expense of prosecuting or defending such suit. In (a) any suit brought by the indemnitee to enforce a right to indemnification hereunder (but not in a suit brought by the indemnitee to enforce a right to an advancement of expenses) it shall be a defense that, and (b) in any suit brought by the Company to recover an advancement of expenses pursuant to the terms of an undertaking, the Company shall be entitled to recover such expenses upon a final adjudication that, the indemnitee has not met any applicable standard for indemnification set forth in the DGCL. Neither the failure of the Company (including its directors who are not parties to such action, a committee of such directors, independent legal counsel, or its stockholders) to have made a determination prior to the commencement of such suit that indemnification of the indemnitee is proper in the circumstances because the indemnitee has met the applicable standard of conduct set forth in the DGCL, nor an actual determination by the Company (including its directors who are not parties to such action, a committee of such directors, independent legal counsel, or its stockholders) that the indemnitee has not met such applicable standard of conduct, shall create a presumption that the indemnitee has not met the applicable standard of conduct or, in the case of such a suit brought by the indemnitee, be a defense to such suit. In any suit brought by the indemnitee to enforce a right to indemnification or to an advancement of expenses hereunder, or brought by the Company to recover an advancement of expenses pursuant to the terms of an undertaking, the burden of proving that the indemnitee is not entitled to be indemnified, or to such advancement of expenses, under this Article VIII or otherwise shall be on the Company.

Section 4. Non-Exclusivity of Rights. The rights to indemnification and to the advancement of expenses conferred in this Article VIII shall not be exclusive of any other right which any person may have or hereafter acquire under any law, agreement, vote of stockholders or directors, provisions of the Certificate of Incorporation or these Bylaws or otherwise.

Section 5. Insurance. The Company may maintain insurance, at its expense, to protect itself and any director, officer, employee or agent of the Company or another Company, partnership, joint venture, trust or other enterprise against any expense, liability or loss, whether or not the Company would have the power to indemnify such person against such expense, liability or loss under the DGCL.

Section 6. Indemnification of Employees and Agents of the Company. Except for those indemnitees entitled to indemnification under Section 1, the Company may, to the extent authorized from time to time by the Board of Directors, grant rights to indemnification and to the advancement of expenses to any employee or agent of the Company to the fullest extent of the provisions of this Article VIII with respect to the indemnification and advancement of expenses of directors and officers of the Company.

Section 7. Nature of Rights. The rights conferred upon indemnitees in this Article VIII shall be contract rights and such rights shall continue as to an indemnitee who has ceased to be a director, officer or employee and shall inure to the benefit of the indemnitee's heirs, executors and administrators. Any amendment, alteration or repeal of this Article VIII that adversely affects any right of an indemnitee or its successors shall be prospective only and shall not limit or eliminate any such right with respect to any proceeding involving any occurrence or alleged occurrence of any action or omission to act that took place prior to such amendment or repeal.

Section 8. Settlement of Claims. The Company shall not be liable to indemnify any indemnitee under this Article VIII for any amounts paid in settlement of any action or claim effected without the Company's written consent, which consent shall not be unreasonably withheld, or for any judicial award if the Company was not given a reasonable and timely opportunity, at its expense, to participate in the defense of such action.

Section 9. Subrogation. In the event of payment under this Article VIII, the Company shall be subrogated to the extent of such payment to all of the rights of recovery of the indemnitee, who shall execute all papers required and shall do everything that may be necessary to secure such rights, including the execution of such documents necessary to enable the Company effectively to bring suit to enforce such rights.

Section 10. Procedures for Submission of Claims. The Board of Directors may establish reasonable procedures for the submission of claims for indemnification pursuant to this Article VIII, determination of the entitlement of any person thereto and review of any such determination. Such procedures shall be set forth in an appendix to these Bylaws and shall be deemed for all purposes to be a part hereof.

ARTICLE IX

AMENDMENTS

Section 1. Amendments of By-laws. These By-laws may be altered, amended, supplemented or repealed and new By-laws may be adopted by an affirmative vote of the holders of 75 percent of the voting power of all shares of outstanding stock of the Company entitled to vote at any duly constituted Annual or Special Meeting of Stockholders, and, except as otherwise expressly provided in a By-law made by the stockholders, by the Board of Directors at any duly constituted regular or special meeting thereof; provided that no amendment of these By-laws changing the place named therein for the annual election of Directors shall be made within sixty days next before the day on which any such election is to be held.

Exhibit 10.21

The Williams Companies, Inc.
Severance Pay Plan

Effective October 28, 2003

THE WILLIAMS COMPANIES, INC.
SEVERANCE PAY PLAN

(As Amended and Restated Effective as of October 28, 2003)

Article 1.
Definitions

The following capitalized words and phrases when used in the text of the Plan shall have the meanings set forth below. Words in the masculine gender shall connote the feminine gender as well.

1.1 "Administrative Committee" means the committee administering this Plan under Article 5.

1.2 "Affiliate" means any Person that directly or indirectly, through one (1) or more intermediaries, controls, is controlled by or is under common control with the Company.

1.3 "Aggregate Compensation" means Regular Wage Base and any annual cash incentive awards from a Participating Company or Affiliate annual incentive program.

1.4 "Base Salary" means the amount a Participant is entitled to receive as wages or salary on an annualized basis, including any salary deferral contributions made to any defined contribution plan maintained by the Participating Company and any amounts contributed by an Employee to any cafeteria plan, flexible benefits plan or qualified transportation plan maintained by the Participating Company in accordance with Sections 125, 132 and related provisions of the Code, but excluding all special pay, bonus, overtime, incentive compensation, commissions, cost of living pay, housing pay, relocation pay, other taxable fringe benefits and all extraordinary compensation, payable by the Company or any of its Affiliates as consideration for the Participant's services, as determined on the date immediately preceding termination of employment, except that in the case of a termination of employment for Good Reason, Base Salary shall be determined as of the date immediately preceding the event which constitutes Good Reason.

1.5 "Benefits Committee" means the Company committee comprised of that group of individuals appointed to act for the Company with respect to the Plan.

1.6 "Board of Directors" means the board of directors of the Company.

1.7 "Cause" means the occurrence of any one (1) or more of the following, as determined in the good faith and reasonable judgment of the Administrative Committee:

(a) willful failure by an Employee to substantially perform his duties (as they existed immediately prior to a reduction in force, job elimination or Change in Control), other than any such failure resulting from a disability as defined in the Participating Company or Affiliate disability program; or

(b) Employee's conviction of or plea of *nolo contendere* to a crime involving fraud, dishonesty or any other act constituting a felony involving moral turpitude or causing material harm, financial or otherwise, to the Company or an Affiliate; or

(c) Employee's willful or reckless material misconduct in the performance of his duties which results in an adverse effect on the Company or an Affiliate; or

(d) Employee's willful or reckless violation or disregard of the code of business conduct or other published policy of the Company or an Affiliate; or

(e) Employee's habitual or gross neglect of duties.

1.8 "Change Date" means the date on which a Change in Control first occurs.

1.9 "Change in Control" means the occurrence of any one (1) or more of the following:

(a) any person (as such term is used in Rule 13d-5 of the SEC under the Exchange Act) or group (as such term is defined in Sections 3(a)(9) and 13(d)(3) of the Exchange Act), other than a "Related Party", becomes the beneficial owner (as defined in Rule 13d-3 under the Exchange Act) of 20 percent or more of the common stock of the Company or of Voting Securities representing 20 percent or more of the combined voting power of all Voting Securities of the Company, except that no Change in Control shall be deemed to have occurred solely by reason of such beneficial ownership by a Person with respect to which both more than 75 percent of the common stock of such Person and Voting Securities representing more than 75 percent of the combined voting power of the Voting Securities of such Person are then owned, directly or indirectly, by the persons who were the direct or indirect owners of the common stock and Voting Securities of the Company immediately before such acquisition, in substantially the same proportions as their ownership, immediately before such acquisition, of the common stock and Voting Securities of the Company, as the case may be; or

(b) the Company's Incumbent Directors (determined using the Effective Date as the baseline) cease for any reason to constitute at least a majority of the directors of the Company then serving; or

(c) a Reorganization Transaction, other than a Reorganization Transaction that results in the Persons who were the direct or indirect owners of the outstanding common stock and Voting Securities of the Company immediately before such Reorganization Transaction becoming, immediately after the consummation of such Reorganization Transaction, the direct or indirect owners, of both at least 65 percent of the then-outstanding common stock of the Surviving Corporation and Voting Securities representing at least 65 percent of the combined voting power of the then-outstanding Voting Securities of the Surviving Corporation, in substantially the same respective proportions as such Persons' ownership of the common stock and Voting Securities of the Company immediately before such Reorganization Transaction; or

(d) approval by the stockholders of the Company of a plan or agreement for the sale or other disposition of all or substantially all of the consolidated assets of the Company or a plan of complete liquidation of the Company, other than any such transaction that would result in

(i) a Related Party owning or acquiring more than 50 percent of the assets owned by the Company immediately prior to the transaction or

(ii) the Persons who were the direct or indirect owners of the outstanding common stock and Voting Securities of the Company immediately before such transaction becoming, immediately after the consummation of such transaction, the direct or indirect owners, of more than 50 percent of the assets owned by the Company immediately prior to the transaction.

Notwithstanding the occurrence of any of the foregoing events, a Change in Control shall not occur with respect to an Employee if, in advance of such event, the Employee agrees in writing that such event shall not constitute a Change in Control.

1.10 "Code" means the Internal Revenue Code of 1986, as amended from time to time. References to a particular section of the Code include references to regulations and rulings thereunder and to successor provisions.

1.11 "Company" means The Williams Companies, Inc., a Delaware corporation and any successor or successors thereto that continue this Plan pursuant to Section 6.1 or otherwise.

1.12 "Comparable Offer of Employment" means an offer of employment for a position with the Company, any of its Affiliates, or any successor of the Company or its Affiliates that provides for Regular Wage Base equal to or greater than the Participant's Regular Wage Base immediately preceding the Participant's termination date. A successor of the Company or any of its Affiliates shall include, but shall not be limited to, any entity (or its Affiliate) involved in or in any way connected with a corporate rearrangement, total or partial merger, acquisition, sale of stock, sale of assets or any other transaction. A Comparable Offer of Employment includes, without limitation, a position that requires the Employee to transfer to a different work location, but only so long as the Employee's commuting distance to the new work location is no longer than the greater of fifty (50) miles or such Participant's current commute if the commuting distance from such Participant's current residence to the original work location is more than fifty (50) miles.

1.13 "Effective Date" means October 28, 2003, which is the effective date of this amendment and restatement.

1.14 "Employee" means any regular full-time or part-time employee in the service and on the payroll of a Participating Company as a common law employee. An Employee is considered as part-time if he is regularly scheduled to work at least fifty percent of the number of hours in the normal workweek established by a Participating Company. A regular employee receiving benefits under a Participating Company's Short-Term Disability Program or Long-Term Disability Program is an Employee for purposes of this Plan. Employee shall not include:

(a) an Employee who is a member of a group of Employees represented by a collective bargaining representative, unless such agreement expressly provides for coverage of bargaining unit employees under the Plan;

(b) an Employee who is not a resident of the United States and not a citizen of the United States;

(c) a nonresident alien;

(d) a weekly-paid employee employed at a retail petroleum convenience store in any capacity other than a store manager;

(e) a seasonal employee, temporary employee, leased employee, term employee, or an employee not employed on a regularly scheduled basis;

(f) a person who has a written employment contract or other contract for services, unless such contract expressly provides that such person is an employee;

(g) a person who is paid through the payroll of a temporary agency or similar organization regardless of any subsequent reclassification as a common law employee;

(h) a person who is designated, compensated or otherwise treated as an independent contractor by a Participating Company or its Affiliates regardless of any subsequent reclassification as a common law employee;

(i) a person who has a written contract with a Participating Company or its Affiliates which states either that such person is not an employee or that such person is not entitled to receive employee benefits from a Participating Company for services under such contract;

(j) an individual who is not contemporaneously classified as an Employee for purposes of the Participating Company's payroll system. In the event any such individual is reclassified as an Employee for any purpose, including, without limitation, as a common law or statutory employee, by any action of any third party, including, without limitation, any government agency, or as a result of any private lawsuit, action or administrative proceeding, such individual will, notwithstanding such reclassification, remain ineligible for participation hereunder and will not be considered an eligible Employee. In addition to and not in derogation of the foregoing, the exclusive means for an individual who is not contemporaneously classified as an Employee of the Participating Company's payroll system to become eligible to participate in this Plan is through an amendment to this Plan which specifically renders such individual eligible for participation hereunder; or

(k) any individual retained by a Participating Company or its Affiliates directly or through an agency or other party to perform services for an Employer (for either a definite or indefinite duration) in the capacity of a fee-for-service worker or independent contractor or any similar capacity including, without limitation, any such individual employed by temporary help firms, technical help firms, staffing firms, employee leasing firms, professional employer organizations or other staffing firms, whether or not deemed to be a "common law" employee.

1.15 "ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time. References to a particular section of ERISA include references to regulations and rulings thereunder and to successor provisions.

1.16 "Exchange Act" means the Securities Exchange Act of 1934, as amended from time to time. References to a particular section of the Exchange Act include references to successor provisions.

1.17 "Good Reason" means the occurrence, within two (2) years following a Change in Control (other than during a Merger of Equals Period) and without a Participant's prior written consent, of any one (1) or more of the following:

(a) a material adverse reduction in the nature or scope of the Participant's duties from the most significant of those assigned at any time in the 90-day period prior to a Change in Control; or

(b) a significant reduction in the authority and responsibility assigned to the Participant; or

(c) any reduction in or failure to pay Participant's Base Salary; or

(d) a material reduction of Participant's Aggregate Compensation and/or aggregate benefits from the amounts and/or levels in effect on the Change Date, unless such reduction is part of a policy applicable to peer Participants of the Company and of any successor entity; or

(e) a requirement by the Company or any of its Affiliates that the Participant's principal duties be performed at a location requiring a commuting distance equal to the greater of the Participant's current commuting distance or more than fifty (50) miles commuting distance, without the Participant's consent (except for travel reasonably required in the performance of the Participant's duties).

Notwithstanding anything in this Plan to the contrary, no act or omission shall constitute grounds for "Good Reason":

(a) Unless, at least thirty (30) days prior to his termination, Participant gives a written notice to the Company or the Affiliate that employs Participant of his intent to terminate his employment for Good Reason which describes the alleged act or omission giving rise to Good Reason; and

(b) Unless such notice is given within ninety (90) days of Participant's first actual knowledge of such act or omission, or if such act or omission would not constitute Good Reason during a Merger of Equals Period, unless Participant's termination date is within 90 days after the first date on which he first obtained actual knowledge of the fact that the Merger of Equals Period has ended; and

(c) Unless the Company or the Affiliate that employs Participant fails to cure such act or omission within the 30-day period after receiving such notice.

Further, no act or omission shall be "Good Reason" if Participant has consented in writing to such act or omission.

1.18 "Incumbent Directors" means determined as of any date by reference to any baseline date:

(a) the members of the Board of Directors on the date of such determination who have been members of the Board of Directors since such baseline date; and

(b) the members of the Board of Directors on the date of such determination who were appointed or elected after such baseline date and whose election, or nomination for election by stockholders of the Company or the Surviving Corporation, as applicable, was approved by a vote or written consent of two-thirds (or by a simple majority for purposes of subsection (b) of the definition of "Merger of Equals") of the directors comprising the Company's Incumbent Directors on the date of such vote or written consent, but excluding each such member whose initial assumption of office was in connection with:

(i) an actual or threatened election contest, including a consent solicitation, relating to the election or removal of one (1) or more members of the Board of Directors,

(ii) a "tender offer" (as such term is used in Section 14(d) of the Exchange Act),

(iii) a proposed Reorganization Transaction, or

(iv) a request, nomination or suggestion of any beneficial owner of Voting Securities representing 20 percent or more of the aggregate voting power of the Voting Securities of the Company or the Surviving Corporation, as applicable.

1.19 "Leave of Absence" means an absence, with or without compensation, authorized on a non-discriminatory basis by the Company or any of its Affiliates. For the purposes of this Plan, Leave of Absence includes any leave of absence other than a Family and Medical Leave of Absence or Military Leave of Absence.

1.20 “Merger of Equals” means, as of any date, a Reorganization Transaction that, notwithstanding the fact that such transaction may also qualify as a Change in Control, satisfies all of the conditions set forth in subsections (a), (b) and (c) below:

(a) less than 65 percent, but not less than 50 percent, of the common stock of the Surviving Corporation outstanding immediately after the consummation of the Reorganization Transaction, together with Voting Securities representing less than 65 percent, but not less than 50 percent, of the combined voting power of all Voting Securities of the Surviving Corporation outstanding immediately after such consummation are owned, directly or indirectly, by the persons who were the owners directly or indirectly of the common stock and Voting Securities of the Company immediately before such consummation in substantially the same proportions as their respective direct or indirect ownership, immediately before such consummation, of the common stock and Voting Securities of the Company, respectively; and

(b) the Company’s Incumbent Directors (determined using the date immediately preceding the consummation date of the Reorganization Transaction as the baseline date) shall, throughout the period beginning on the date of such consummation and ending on the second anniversary of such consummation date, continue to constitute not less than 50 percent of the members of the Board of Directors; and

(c) the person who was the Chief Executive Officer immediately prior to the consummation of the Reorganization Transaction shall serve as the Chief Executive Officer of the Surviving Corporation at all times during the period commencing on such consummation, and ending on the first anniversary of the date of such consummation; provided, however, that a Reorganization Transaction that qualifies as a Change in Control and a Merger of Equals shall cease to qualify as a Merger of Equals and shall instead qualify as a Change in Control that is not a Merger of Equals from and after the first date within the two-year period following the Change in Control (such date, the “Merger of Equals Cessation Date”) as of which any one (1) or more of the following shall occur for any reason:

(i) any condition of subsection (a) of this Section shall for any reason not be satisfied immediately after the consummation of the Reorganization Transaction; or

(ii) as of the close of business on any date on or after the consummation of the Reorganization Transaction and before the second anniversary of the Change Date, any condition of subsections (a) and/or (b) of this Section shall not be satisfied; or

(iii) on any date prior to the first anniversary of the consummation of the Reorganization Transaction, the Company shall make a filing with the SEC, issue a press release, or make a public announcement to the effect that the Chief Executive Officer has resigned or will resign or be terminated, other than on account of a scheduled retirement, or the Company is seeking or intends to seek a replacement for the then-Chief Executive Officer, whether such resignation, termination or replacement is to become effective before or after such first anniversary of the consummation of the Reorganization Transaction.

1.21 "Merger of Equals Cessation Date" shall be the meaning set forth in the definition of "Merger of Equals" Section 1.20.

1.22 "Merger of Equals Period" means the period commencing on the date of a Merger of Equals and ending the earlier of the Merger of Equals Cessation Date or two (2) years following the Change Date.

1.23 "Participant" means an Employee participating in the Plan as provided in Article 2.

1.24 "Participating Company" means the Company and any Affiliate of the Company, which has adopted this Plan in accordance with Section 6.11.

1.25 "Person" means any individual, sole proprietorship, partnership, joint venture, limited liability company, trust, unincorporated organization, association, corporation, institution, public benefit corporate, entity or government instrumentality, division, agency, body or department.

1.26 "Plan" means The Williams Companies, Inc. Severance Pay Plan.

1.27 "Plan Administrator" means the Administrative Committee appointed under Article 5.

1.28 "Plan Year" means the twelve (12) month period from January 1 through December 31.

1.29 "Regular Wage Base" means an Employee's total weekly salary or wages, including any salary deferral contributions made to any defined contribution plan maintained by the Participating Company and any amounts contributed by an Employee to any cafeteria plan, flexible benefit plan or qualified transportation plan maintained by the Participating Company in accordance with Sections 125, 132 and related provisions of the Code, but excluding any bonuses, overtime, incentive compensation, commissions, cost of living pay, housing pay, relocation pay, other taxable fringe benefits and all other extraordinary compensation.

1.30 "Related Party" means an Affiliate or any employee benefit plan (or any related trust) sponsored or maintained by the Company or any of its Affiliates.

1.31 "Reorganization Transaction" means the consummation of a merger, reorganization, recapitalization, consolidation or similar transaction involving the Company.

1.32 "SEC" means the United States Securities and Exchange Commission, or any successor thereto.

1.33 "Sponsor" means The Williams Companies, Inc., a Delaware corporation.

1.34 "Surviving Corporation" means the corporation resulting from a Reorganization Transaction or, if securities representing at least 50 percent of the aggregate voting power of all Voting Securities of such resulting corporation are directly or indirectly owned by another corporation, such other corporation.

1.35 "Voting Securities" means any securities of the Company that are entitled to vote generally in the election of directors.

1.36 "Years of Service" means a Participant's length of service with the Participating Company as set by the latest hire date or rehire date of such Participant. For purposes of this Plan, after the first year of service as a Participant, only full, completed years of service will be counted. Service with a predecessor company will not be included unless, and to the extent that, the Plan Administrator determines such service be included and notifies the Participant in writing that such service is included.

If a Participant is terminated for any reason other than Cause and is rehired by the Participating Company within twelve (12) months of such termination date, years of service prior to such termination will be bridged and used in determining years of service for the purposes of severance pay benefits in the event the Participant becomes eligible for severance pay. The Plan Administrator's determination of Years of Service in its sole and absolute discretion will be final and binding on all persons to the maximum extent permitted by law.

Article 2.
Eligibility

2.1 Eligibility. Any Employee, who is not excluded pursuant to Section 2.2, shall be entitled to become a Participant in the Plan when all of the following conditions are met:

(a) The senior officer of the Company responsible for compensation or benefits, or such senior officer's designee, approves the reduction in force or job elimination and the Employee is notified in writing that employment is being terminated due to a reduction in force which has caused the elimination of his position; or an Employee's employment is terminated involuntarily or voluntarily for Good Reason within two (2) years after a Change in Control, or involuntarily immediately prior to a Change in Control for the purpose of avoiding application of this Plan.

(b) The Employee remains in employment until his designated termination date unless an earlier departure date will not have an adverse effect on the activities of the department and is approved, in writing, by the Employee's department head, unless the employee terminates employment voluntarily for Good Reason within two (2) years after a Change in Control.

2.2 Exclusions. Notwithstanding the provisions of Section 2.1, an Employee will not become a Participant in the Plan if any of the following conditions occur:

(a) An Employee discharged for Cause.

(b) An Employee voluntarily resigns for any reason, including retirement, except in the case of voluntary resignation for Good Reason within two (2) years after a Change in Control.

(c) An Employee accepts any benefits under an early retirement incentive plan.

(d) An Employee fails to make a bona fide effort to secure employment within a Participating Company or any of its Affiliates, or any successor of the Company or its Affiliates.

(e) An Employee transfers to or receives a Comparable Offer of Employment from a Participating Company or any of its Affiliates.

(f) An Employee receives a Comparable Offer of Employment after a corporate rearrangement, total or partial merger, acquisition, sale of stock, sale of assets or other transaction.

(g) An Employee accepts an offer of employment with a Participating Company or any of its Affiliates, whether or not such offer of employment constitutes a Comparable Offer of Employment.

(h) An Employee accepts an offer of employment with any purchaser company or resultant entity, or an affiliate of such a company or entity, after a corporate rearrangement, total or partial merger, acquisition, sale of stock, sale of assets or other transaction, whether or not such offer of employment constitutes a Comparable Offer of Employment.

(i) An Employee dies prior to his termination of employment.

(j) Except as provided in subsection (k), an Employee on a Leave of Absence at the time he is notified that his employment is being terminated due to a reduction in force.

(k) An Employee receiving benefits under the Short-Term Disability Program. This exclusion may not apply if the Employee would have returned to work within the initial six-month period of short-term disability had his termination of employment not occurred and a senior officer of the Company responsible for compensation or benefits, or such senior officer’s designee, approves eligibility for severance upon release to return to work in his sole discretion. This exclusion does not apply in the event of a Change in Control.

(l) An Employee receiving benefits under the Long-Term Disability Program.

(m) An Employee has a written employment contract which contains severance provisions.

(n) An Employee received or is eligible to receive more favorable severance pay benefits under any other severance pay plan, agreement or arrangement of a Participating Company, any of its Affiliates, or any successor of a Participating Company.

Article 3.
Benefits

3.1 Severance Pay. Except as provided in Section 3.7, subject to the Participant signing a release of claims prepared by the Company, a Participant will be eligible for severance pay benefits under this Section 3.1 equal to:

(a) the product of (i) two (2) weeks multiplied by (ii) the Participant's Regular Wage Base, if the Participant has less than one (1) full-completed Year of Service; or

(b) the product of (i) two (2) weeks for each full, completed Year of Service, with a minimum of six (6) weeks and a maximum of fifty-two (52) weeks, multiplied by (ii) the Participant's Regular Wage Base, if the Participant has completed at least one (1) full Year of Service.

3.2 Change in Control Severance Pay. Subject to the Participant signing a release of claims prepared by the Company, if a Participant's employment is terminated voluntarily for Good Reason or involuntarily within two (2) years after a Change in Control, the Participant will be eligible for severance pay benefits under this Section 3.2 in lieu of any benefits under Section 3.1 with the amount of such benefits equal to the sum of:

(a) the product of (i) the number of the Participant's full, completed Years of Service multiplied by (ii) three (3), and multiplied by (iii) the Participant's Regular Wage Base;

(b) the product of (i) Participant's Regular Wage Base multiplied by (ii) the quotient of the Participant's Base Salary divided by ten thousand (10,000); and

(c) the product of (i) the Participant's target annual bonus (with respect to the calendar year in which the termination occurs) multiplied by (ii) a fraction, the numerator of which equals the number of days from and including the first day of such calendar year through and including the date of termination, and the denominator of which equals three hundred and sixty-five (365) (reduced by any annual bonus amount received with respect to such calendar year).

Notwithstanding the foregoing, the sum of subsections (a) and (b) of this Section 3.2 shall not be less than the product of the Participant's Regular Wage Base multiplied by twelve (12) nor more than the product of the Participant's Regular Wage Base multiplied by one hundred and four (104).

3.3 Notice. Any Participant who is terminated and receives less than two (2) weeks notice from a Participating Company will receive, in addition to the benefits provided in Section 3.1 or 3.2 (whichever applies), severance pay for the lack of notice. Weeks or fractions thereof, will be granted which is equal to the difference between two (2) weeks and the number of days notice received by the Participant. The amount of severance pay will be equal to the number of weeks and/or fractions thereof granted to a Participant under this Section 3.3

times the Participant's Regular Wage Base. No payment will be made under this Section 3.3 if total severance pay exceeds the maximum benefit allowed.

3.4 Form of Payment. Severance benefits payable to a Participant under Section 3.1 shall be paid in installments over a period not to exceed one (1) year from the date payment commences. Severance benefits payable to a Participant under Section 3.2 shall be paid in a lump sum within thirty days from the date of the Participant's termination of employment.

3.5 Other Benefit Plans. Participants, regardless of whether they sign the release of claims required to receive severance payments, who are otherwise entitled to receive severance pay and who are eligible to continue participation in certain welfare benefit plans may choose to continue their participation in accordance with this Section 3.5. Continued participation in such welfare benefit plans is subject to the terms and conditions of the applicable plan documents or insurance contracts in effect on the date of the Participant's termination from employment. Generally, the Participant has the option to elect the currently maintained Participating Company group medical and dental plan that he is currently enrolled for up to 18 months under the Consolidated Omnibus Budget Reconciliation Act (COBRA) continuation coverage. If the Participant timely and properly elects COBRA coverage, the premiums for COBRA coverage will be limited to the active employee rate for the initial three months of coverage. At the end of this three-month period, the Participant will be required to pay the full cost for medical and/or dental benefits under COBRA for the remainder of the 18-month period. Participation in the Participating Company group medical and dental plan will generally cease on the date the Participant or his dependents become covered under any other medical plan or dental plan.

3.6 Paid-Time Off (PTO) Program. A Participant, regardless of whether he signs the release of claims required to receive severance payments, shall be paid a single lump sum payment for applicable PTO hours earned but not taken prior to the Participant's employment termination. PTO time will not be considered for purposes of continued coverage under any of the other various employee benefit plans maintained by the Participating Company.

3.7 Rehired Participants after Receipt of Severance Pay.

This Section 3.7 applies to Participants rehired by a Participating Company or any Affiliate after receipt of severance pay under Section 3.1.

(a) Severance Pay. The Participant will be entitled to keep a portion of his severance pay equal to the number of weeks and/or fraction of weeks between his termination date and the date of rehire. Any remainder must be returned to the Participating Company that paid the severance pay upon rehire or it will be deducted from his wages paid after rehire.

If a Participant is rehired within twelve (12) months of his termination date and again becomes eligible for severance pay due to a subsequent event within twelve (12) months of rehire, subject to the Participant signing a release of claims prepared by the Company, the Participant will be eligible to receive the greater of

(i) the sum of any remaining severance not yet received from the initial termination date in accordance with Section 3.1, plus two (2) weeks of severance pay or

(ii) two (2) weeks of severance pay.

Severance pay under this Section 3.7 will be paid in accordance with Section 3.4.

(b) PTO. If a Participant is rehired within the same calendar year in which his employment was terminated and he received payment for PTO earned but not taken, he may either retain the payment and forfeit PTO time for which he was eligible prior to his employment termination, or he may return to the Company the amount he received and reinstate PTO time for which he was eligible prior to termination.

3.8 Discretionary Benefits. Under no circumstances will any discretionary benefits be paid unless the senior officer of the Company responsible for compensation or benefits, or such senior officer's designee, signs a written document describing such benefits. Payment of such discretionary benefits will be made only in accordance with the terms of that document.

3.9 No Vesting. Employees have no vested right to any benefits set forth in the Plan until such time as an Employee becomes entitled to receive benefits under Article 2; however, the Participant must execute a release in accordance with Section 3.1 or 3.2 (whichever applies) to receive any benefits under this Plan.

3.10 Integration with Plant Closing Law(s). To the extent that a federal, state or local law, including, but not limited to the Worker Adjustment and Retraining Act, requires a Participating Company, as an employer, to provide notice and/or make a payment to an Employee because of that Employee's involuntary termination, or pursuant to a plant closing law, the benefit payable under this Plan, including without limitation benefits payable under Section 3.3, shall be reduced by any Regular Wage Base paid during such notice period and/or by such other required payment.

Nothing in this section or any other section of this Plan shall be used to reduce benefits under this Plan because of payments under state unemployment insurance laws.

Article 4.
Claims

4.1 Claims for Benefits. To obtain payment of any benefits under the Plan, a Participant must comply with such rules and procedures as the Plan Administrator may prescribe.

4.2 Claims Procedure. The Plan Administrator shall adopt, and may change from time to time, claims procedures, provided that such claims procedures and changes thereof shall conform to Section 503 of the Employee Retirement Income Security Act of 1974 and the regulations promulgated thereunder. Such claims procedures, as in effect from time to time, shall be deemed to be incorporated herein and made a part hereof.

Article 5.
Administration

5.1 Fiduciaries. The Administrative Committee is designated as the only named fiduciary of the Plan as defined in ERISA.

5.2 Allocation of Responsibilities.

(a) Board of Directors. The Board of Directors (through its delegatee, the Compensation Committee of the Board of Directors) shall have exclusive authority and responsibility, including the power to amend the Plan in Section 6.3 to the extent necessary, for:

Plan matters that are deemed to be material under the corporate laws of the State of Delaware to holders of common stock of the Company; and

The delegation to the Benefits Committee or other appropriate person of any authority and responsibility reserved to it under the Plan that it can delegate.

(b) Benefits Committee. The Benefits Committee shall have exclusive authority and responsibility for those functions set forth in Section 5.3 and in other provisions of this Plan.

(c) Administrative Committee The Administrative Committee shall serve as the Plan Administrator and shall have exclusive authority and responsibility for those functions set forth in Section 5.4 and in other provisions of this Plan.

5.3 Provisions Concerning the Benefits Committee.

(a) Membership and Voting. Any member may resign by delivering a written resignation to the Board of Directors. The Board of Directors shall fill vacancies in the Benefits Committee arising by death, resignation or removal. The Benefits Committee shall act by a majority of its members at the time in office, and such action may be taken by a vote at a meeting, in writing without a meeting, or by telephonic communications. Attendance at a meeting shall constitute waiver or notice thereof. A member of the Benefits Committee who is a Participant of the Plan shall not vote on any question relating specifically to such Participant. Any such action shall be voted or decided by a majority of the remaining members of the Benefits Committee. The Benefits Committee shall appoint a Secretary who may, but need not, be a member thereof. The Benefits Committee may appoint from its members such subcommittees with such powers as the Benefits Committee shall determine.

(b) Powers and Duties of Benefits Committee. The Benefits Committee shall have exclusive authority and responsibility for:

(i) All amendments to this Plan, except to the extent such authority is reserved to the Board of Directors, as provided in Articles 5 and 6;

(ii) The termination or other discontinuance of this Plan, in whole or in part;

(iii) The approval of any merger or spin-off of any part of this Plan;

(iv) The delegation of its fiduciary responsibilities, if any, under the Plan to another person or entity; and

(v) The appointment of members of the Administrative Committee, but only to fill vacancies not filled by the Administrative Committee, and the appointment of the chairman of the Administrative Committee, but only if a chairman is not timely selected by the Administrative Committee's members.

The Benefits Committee may appoint such accountants, counsel, specialists, and other persons, as it deems necessary or desirable in connection with its duties under this Plan. Such accountants and counsel may, but need not, be accountants and counsel for the Company or an Affiliate. The Benefits Committee also shall have such other duties, authority and responsibility under this Plan as may be delegated by the Board of Directors.

5.4 Provisions Concerning the Administrative Committee.

(a) Membership and Voting. The Administrative Committee shall consist of not less than three (3) members. All members of the Administrative Committee must be Employees of the Company. The Administrative Committee may remove any of its members at any time, with or without cause, by written notice to such member and to the Benefits Committee. Any member may resign by delivering a written resignation to the Administrative Committee. Vacancies in the Administrative Committee arising by death, resignation or removal shall be filled by the Administrative Committee, or the Benefits Committee to the extent not filled by the Administrative Committee. The Administrative Committee shall act by a majority of its members at the time in office, and such action may be taken by a vote at a meeting, in writing without a meeting, or by telephonic communications. Attendance at a meeting shall constitute waiver of notice thereof. A member of the Administrative Committee who is a Participant of the Plan shall not vote on any question relating specifically to such Participant. Any such action shall be voted or decided by a majority of the remaining members of the Administrative Committee. The Administrative Committee shall designate one of the members as the chairman and shall appoint a secretary who may, but need not, be a member, but the Benefits

Committee may appoint a chairman if the Administrative Committee fails to do so. The Administrative Committee may appoint from its members such subcommittees with such powers as the Administrative Committee shall determine.

(b) Duties of Administrative Committee. The Administrative Committee shall administer the Plan in accordance with its terms and shall have all the powers necessary to carry out such terms including, without limitation, the power, in its sole and absolute discretion, to determine all benefits and to grant or to deny claims for benefits. The Administrative Committee shall execute any certificate, instrument or other written direction on behalf of the Plan. All interpretations of this Plan, and all questions concerning its administration and application, including without limitation, all benefit determinations and all claim decisions, shall be determined by the Administrative Committee (or its delegate) in its sole and absolute discretion and such determination shall be conclusive and binding on all persons to the maximum extent permitted by law. No determination of the Administrative Committee for any Participant shall create a basis for retroactive adjustment for any other Participant. The Administrative Committee may appoint such accountants, counsel, specialists and other persons as it deems necessary or desirable in connection with the administration of the Plan. Such accountants and counsel may, but need to, be accountants and counsel for the Company or an Affiliate. The Administrative Committee shall also have such other duties as the Benefits Committee may delegate. The Administrative Committee shall report regularly, and at least once each Plan Year, on its operations to the Benefits Committee.

5.5 Delegation of Responsibilities; Bonding.

(a) Delegation and Allocation. The Administrative Committee shall have the authority to delegate or allocate, from time to time, by a written instrument, all or any part of its responsibilities under this Plan to such person or persons as it may deem advisable and in the same manner to revoke any such delegation or allocation of responsibility. Any action of a person in the exercise of such delegated or allocated responsibility shall have the same force and effect for all purposes hereunder as if such action had been taken by the Administrative Committee. The Administrative Committee shall not be liable for any acts or omissions of any such person, who shall periodically report to the Administrative Committee concerning the discharge of the delegated or allocated responsibilities.

(b) Bonding. The members of the Benefits Committee, and the Administrative Committee shall serve without bond (except as expressly required by federal law) and without compensation for their services as such.

5.6 No Joint Fiduciary Responsibilities. This Plan is intended to allocate to the Administrative Committee the individual responsibility for the prudent execution of the functions assigned to it, and none of such responsibilities or any other responsibility shall be shared by any other fiduciaries under the Plan unless such sharing is provided for by a specific provision of the Plan. Whenever one fiduciary is required herein to follow the directions of another fiduciary, the two fiduciaries shall not be deemed to have been assigned a shared responsibility, but the responsibility of a fiduciary receiving such directions shall be to follow them insofar as such instructions are on their face proper under applicable law.

5.7 Fiduciary Capacity. Any person or group of persons may serve in more than one fiduciary capacity with respect to the Plan.

5.8 Information to be Supplied by Participating Company. Each Participating Company shall supply to the Administrative Committee, within a reasonable time and in such form as the Administrative Committee shall require, the names of all Employees who incurred a Termination of Employment or layoff during the month, the date of termination of each, and the amount of compensation paid to each Active Participant for the month. The Administrative Committee may rely conclusively on the information certified to it by a Participating Company. Each Participating Company shall provide to the Administrative Committee or its delegate such information as it shall from time to time need in the discharge of its duties.

5.9 Right to Receive and Release Necessary Information. The Administrative Committee may release or obtain any information necessary for the application, implementation and determination of this Plan or other Plans without consent or notice to any person. This information may be released to or obtained from any insurance company, organization or person. Any individual claiming benefits under this Plan shall release to the Administrative Committee such information as the Administrative Committee, in its sole and absolute discretion, determines to be necessary to implement this provision.

Article 6.
General Provisions

6.1 Successor to Company. This Plan shall bind any successor (whether direct or indirect, by purchase, merger, consolidation, reorganization or otherwise) which becomes such after Change in Control (Merger of Equals) has occurred to all or substantially all of the business and/or assets of the Company in the same manner and to the same extent that the Company would be obligated under this Plan if no succession had taken place. In the case of any transaction in which a successor (which becomes such after a Change in Control [Merger of Equals] of the Company has occurred) would not by the foregoing provision or by operation of law be bound by this Plan, the Company shall require such successor expressly and unconditionally to assume and agree to perform the Company’s obligations under this Plan, in the same manner and to the same extent that the Company would be required to perform if no such succession had taken place. The term “Company,” as used in this Plan, shall mean the Company and any successor or assignee to the business or assets that by reason hereof becomes bound by this Plan.

6.2 Duration. The Plan shall continue indefinitely unless terminated as provided in subsection 6.3 hereof.

6.3 Amendment and Termination. Except as provided in Section 5.2(a), the Benefits Committee may amend, modify, change, revise or discontinue this Plan at any time prior to a Change in Control occurring or within twelve (12) months after a Change in Control has occurred; provided, however, that any such action taken that has the effect of reducing Participant benefits under this Plan prior to a Change in Control shall not be effective before six (6) months after adoption and shall be null and void if a Change in Control occurs during that period.

6.4 Management Rights. Participation in the Plan shall not lessen or otherwise affect the responsibility of an Employee to perform fully his duties in a satisfactory and workmanlike manner. This Plan shall not be deemed to constitute a contract between a Participating Company and any employee or other person whether or not in the employ of the Participating Company, nor shall anything herein contained be deemed to give any employee or other person whether or not in the employ of a Participating Company any right to be retained in the employ of any Participating Company, or to interfere with the right of any Participating Company to discharge any employee at any time and to treat him without any regard to the effect which such treatment might have upon him as an employee covered by the Plan.

6.5 Funding. The Plan shall constitute an unfunded and unsecured obligation of the Participating Companies payable from the general funds of such Participating Companies.

6.6 Withholding of Taxes. Each Participating Company may withhold from any amounts payable under the Plan all federal, state, city and/or other taxes as shall be legally required.

6.7 Participant's Responsibility. Each Participant (or personal representative of a deceased Participant's estate) shall be responsible for providing the Administrative Committee with his current address. Any notices required or permitted to be given hereunder shall be deemed given if directed to such address and mailed by regular United States mail. The Administrative Committee shall not have any obligation or duty to locate a Participant.

6.8 Indemnification. Each Participating Company shall indemnify and hold harmless each member of the Board of Directors, each member of the Benefits Committee, each member of the Administrative Committee and each officer and employee of a Participating Company to whom are delegated duties, responsibilities, and authority with respect to this Plan against all claims, liabilities, fines and penalties, and all expenses reasonably incurred by or imposed upon him (including, but not limited to reasonable attorney fees) which arise as a result of his actions or failure to act in connection with the operation and administration of this Plan to the extent lawfully allowable and to the extent that such claim, liability, fine, penalty, or expense is not paid for by liability insurance purchased or paid for by a Participating Company. Notwithstanding the foregoing, a Participating Company shall not indemnify any person for any such amount incurred through any settlement or compromise of any action unless the Participating Company consents in writing to such settlement or compromise.

6.9 Governing Law. The Plan shall be governed by and construed in accordance with applicable Federal laws, including ERISA, governing employee benefit plans and in accordance with the laws of the State of Oklahoma where such laws are not in conflict with the aforementioned federal laws.

6.10 Right of Recovery. If any Participating Company makes payment(s) in excess of the amount required under the Plan, the Administrative Committee shall have the right to recover the excess payment(s) from any person who received the excess payment(s). Such recovery shall be returned by the Administrative Committee to such Participating Company.

6.11 Adoption by Participating Company. Any Affiliate may adopt or withdraw from this Plan. The adoption resolution may contain such specific changes and variations in this Plan's terms and provisions applicable to the employees of the adopting Participating Company as may be acceptable to the Administrative Committee.

IN WITNESS WHEREOF, the Benefits Committee has caused this amended and restated Plan to be executed effective as herein provided.

BY: /s/ Marcia M. MacLeod
Marcia M. MacLeod
Benefits Committee Member

Exhibit 10.22

AMENDMENT TO THE
WILLIAMS COMPANIES, INC. SEVERANCE PAY PLAN

The Williams Companies, Inc. Severance Pay Plan, as amended and restated effective October 28, 2003 and as subsequently amended ("Plan"), shall be, and hereby is, amended in the following respects, effective October 28, 2003:

I.

Section 1.5 of the Plan is amended in its entirety to provide as follows:

"1.5 'Benefits Committee' means the committee comprised of that group of individuals appointed to undertake those duties as described in Articles V and VI of the Plan."

II.

The following is added as a new Section 1.12A following Section 1.12 in the Plan:

"1.12A 'Compensation Committee' means the Committee of the Board of Directors designated as the Compensation Committee."

III.

Section 5.1 is amended in its entirety to provide as follows:

"5.1 Fiduciaries. The Administrative Committee is designated as the named fiduciary as defined in ERISA; provided that any claims administrator will be a named fiduciary with respect to claims and appeals related to benefit determinations."

IV.

Section 5.2(a) of the Plan is amended in its entirety to provide as follows:

"5.2 Allocation of Responsibilities.

(a) Compensation Committee. The Compensation Committee shall have exclusive authority and responsibility, including the power to amend the Plan in Section 6.3 to the extent necessary, for:

(i) Plan matters that are deemed to be material under the corporate laws of the State of Delaware to holders of common stock of the Company;

(ii) The veto of appointments to the Benefits Committee within ninety (90) days of receipt of notice of an appointment to the Benefits Committee; and

(iii) The delegation to the Benefits Committee or other appropriate person of any authority and responsibility reserved to it under the Plan that it can delegate."

V.

Section 5.3(a) of the Plan is amended in its entirety to provide as follows:

(a) Membership and Voting. The Benefits Committee shall consist of not less than three (3) members and not more than five (5) members and vacancies of the Benefits Committee shall be filled by the remaining members of the Benefits Committee; provided the Compensation Committee shall have the authority to veto appointments to the Benefits Committee within ninety (90) days of receipt of notice of an appointment to the Benefits Committee and provided further that the Chairman of the Benefits Committee shall notify the Compensation Committee of new appointments to the Benefits Committee within sixty (60) days of such appointment.

VI.

Section 5.3(b) of the Plan is amended in its entirety to provide as follows:

"(b) Powers and Duties of Benefits Committee. The Benefits Committee shall have exclusive authority and responsibility for:

(i) All amendments to this Plan, except to the extent such authority is reserved to the Compensation Committee, as provided in Articles V and VI;

(ii) The termination or other discontinuance of this Plan, in whole or in part;

(iii) The approval of any merger or spin-off of any part of this Plan;

(iv)The appointment of members of the Administrative Committee, but only to fill vacancies not filled by the Administrative Committee, and the appointment of the chairman of the Administrative Committee, but only if a chairman is not timely selected by the Administrative Committee's members.

(v) Solely to assist the Compensation Committee in its settlor capacity, the Benefits Committee shall report to the Compensation Committee of material developments in and changes to the general employee benefit matters of the Plan at least one time each year, but not later than ninety (90) days after the end of the Company's fiscal year.

The Benefits Committee may appoint such accountants, counsel, specialists, and other persons, as it deems necessary or desirable in connection with its duties under this Plan. Such accountants and counsel may, but need not, be accountants and counsel for the Company or an Affiliate. The Benefits Committee also shall have such other duties, authority and responsibility under this Plan as may be delegated by the Board of Directors or Compensation Committee."

VII.

Section 5.6 of the Plan is amended in its entirety to provide as follows:

"5.6 No Joint Fiduciary Responsibilities. This Plan is intended to allocate to the Administrative Committee the individual responsibility for the prudent execution of the functions assigned to it, and none of such responsibilities or any other responsibility shall be shared by any other entity unless such sharing is provided for by a specific provision of the Plan. Whenever one fiduciary is required herein to follow the directions of another fiduciary, the two fiduciaries shall not be deemed to have been assigned a shared responsibility, but the responsibility of a fiduciary receiving such directions shall be to follow them insofar as such instructions are on their face proper under applicable law."

VIII.

Section 6.3 of the Plan is amended in its entirety to provide as follows:

"6.3 Amendment and Termination. Except as provided in Section 5.2(a), the Benefits Committee may, in its sole and absolute discretion, amend, modify, change, revise or discontinue this Plan at any time prior to a Change in Control occurring or within 12 months after a Change in Control has occurred; provided, however, that any such action taken that has the effect of reducing Participants benefits under this Plan prior to a Change in Control shall not be effective before six months after adoption and shall be null and void if a Change in Control occurs during that period."

XIV.

Except as modified herein, the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, the Benefits Committee has caused this Amendment to the Plan to be executed effective as herein provided.

By: /s/ Marcia M. MacLeod
Marcia M. MacLeod
Benefits Committee Member

Exhibit 10.23

AMENDMENT TO THE
WILLIAMS COMPANIES, INC. SEVERANCE PAY PLAN

The Williams Companies Severance Pay Plan, as amended and restated effective October 28, 2003 and as subsequently amended ("Plan"), shall be, and hereby is, amended in the following respects, effective June 1, 2004:

I.

Section 1.12 of the Plan is amended in its entirety to provide as follows:

"1.12 'Comparable Offer of Employment' means an offer of employment for a position with the Company, any of its Affiliates, or any successor of the Company or its Affiliates that provides for Regular Wage Base equal to or greater than the Participant's Regular Wage Base immediately preceding the Participant's termination date. A successor of the Company or any of its Affiliates shall include, but shall not be limited to, any entity (or its Affiliate) involved in or in any way connected with a corporate rearrangement, total or partial merger, acquisition, sale of stock, sale of assets or any other transaction. A Comparable Offer of Employment includes, without limitation, a position that requires the Employee to transfer to a different work location, but only so long as the Employee's commuting distance to the new work location is not increased more than fifty (50) miles beyond the commuting distance to his or her current work location."

II.

Section 1.17 of the Plan is amended in its entirety to provide as follows:

"1.17 'Good Reason' means the occurrence, within two (2) years following a Change in Control (other than during a Merger of Equals Period) and without a Participant's prior written consent, of any one (1) or more of the following:

(a) a material adverse reduction in the nature or scope of the Participant's duties from the most significant of those assigned at any time in the 90-day period prior to a Change in Control; or

(b) a significant reduction in the authority and responsibility assigned to the Participant; or

(c) any reduction in or failure to pay Participant's Base Salary; or

(d) a material reduction of Participant's Aggregate Compensation and/or aggregate benefits from the amounts and/or levels in effect on the Change

Date, unless such reduction is part of a policy applicable to peer Participants of the Company and of any successor entity; or

(e) a requirement by the Company or any of its Affiliates that the Participant's principal duties be performed at a location requiring a commuting distance to the new work location greater than fifty (50) miles beyond the commuting distance to his or her current work location, without the Participant's consent (except for travel reasonably required in the performance of the Participant's duties).

Notwithstanding anything in this Plan to the contrary, no act or omission shall constitute grounds for 'Good Reason': unless, at least thirty (30) days prior to his termination, Participant gives a written notice to the Company or the Affiliate that employs Participant of his intent to terminate his employment for Good Reason which describes the alleged act or omission giving rise to Good Reason; and unless such notice is given within ninety (90) days of Participant's first actual knowledge of such act or omission, or if such act or omission would not constitute Good Reason during a Merger of Equals Period, unless Participant's termination date is within 90 days after the first date on which he first obtained actual knowledge of the fact that the Merger of Equals Period has ended; and unless the Company or the Affiliate that employs Participant fails to cure such act or omission within the 30-day period after receiving such notice.

Further, no act or omission shall be 'Good Reason' if Participant has consented in writing to such act or omission."

III.

Except as modified herein, the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, the Benefits Committee has caused this Amendment to the Plan to be executed effective as herein provided.

By: /s/ Michael P. Johnson
Michael P. Johnson
Benefits Committee Member

Exhibit 10.24

AMENDMENT TO
THE WILLIAMS COMPANIES, INC. SEVERANCE PAY PLAN

The Williams Companies, Inc. Severance Pay Plan, as amended and restated effective October 28, 2003, and as subsequently amended ("Plan"), shall be, and hereby is, amended in the following respects, effective January 1, 2005:

I.

Section 1.1 of the Plan is amended in its entirety to provide as follows:

"1.1 'Administrative Committee' means the committee appointed to administer this Plan which is comprised of those individuals who are serving on the Administrative Committee on December 31, 2004, as well as any individual who becomes a member of the Administrative Committee pursuant to Section 5.4, until the time that any such individual ceases to be a member of the Administrative Committee pursuant to Section 5.4 of the Plan. The duties of the Administrative Committee are described in Article V of the Plan."

II.

Section 1.5 of the Plan is amended in its entirety to provide as follows:

"1.5 'Benefits Committee' means the committee comprised of those individuals who were serving on the Benefits Committee on December 31, 2004, as well as any individual who becomes a member of the Benefits Committee pursuant to Section 5.3, until the time that any such individual ceases to be a member of the Benefits Committee pursuant to Section 5.3 of the Plan. The duties of the Benefits Committee are described in Articles V and VI of the Plan."

III.

Section 5.1 of the Plan is amended in its entirety to provide as follows:

"5.1 Fiduciaries. Under certain circumstances, the Administrative Committee may be determined by a court of law to be a fiduciary with respect to a particular action under the Plan; provided that any claims administrator will be a named fiduciary with respect to claims and appeals related to benefit determinations."

IV.

Section 5.2 of the Plan is amended in its entirety to provide as follows:

"5.2 Allocation of Responsibilities.

(a) Administrative Committee. The Administrative Committee shall serve as Plan Administrator and shall have exclusive authority and responsibility for those functions set forth in Section 5.4 and in other provisions of this Plan.

(b) Claims Administrator. Claims Administrator shall have the responsibility to make claims and appeals decisions related to benefit determinations in accordance with the claims procedure."

V.

Section 5.3 of the Plan is amended in its entirety to provide as follows:

"5.3 Provisions Concerning the Benefits Committee.

(a) Membership and Voting. The Benefits Committee shall consist of not less than three (3) members and not more than five (5) members and vacancies of the Benefits Committee shall be filled by the remaining members of the Benefits Committee.

(b) Powers and Duties of Benefits Committee. The Benefits Committee shall have the authority and responsibility for:

(1) Those responsibilities as detailed in Article VI.

The Benefits Committee may appoint such accountants, counsel, specialists, and other persons as it deems necessary or desirable in connection with its duties under this Plan. Such accountants and counsel may, but need not, be accountants and counsel for the Company or an affiliate."

VI.

Section 5.4 of the Plan is amended in its entirety to provide as follows:

“5.4 Provisions Concerning the Administrative Committee.

(a) Membership and Voting. The Administrative Committee shall consist of not less than three (3) members. The Administrative Committee may remove any of its members at any time, with or without cause, by written notice to such member. Any member may resign by delivering a written resignation to the Administrative Committee. Vacancies in the Administrative Committee arising by death, resignation or removal shall be filled by the Administrative Committee. The Administrative Committee shall act by a majority of its members at the time in office, and such action may be taken by a vote at a meeting, in writing without a meeting, or by telephonic communications. Attendance at a meeting shall constitute waiver of notice thereof. A member of the Administrative Committee who is a Participant in the Plan shall not vote on any question relating specifically to such Participant. Any such action shall be voted or decided by a majority of the remaining members of the Administrative Committee. The Administrative Committee shall designate one of its members as the Chairman and shall appoint a Secretary who may, but need not, be a member. The Administrative Committee may appoint from its members such subcommittees with such powers as the Administrative Committee shall determine.

(b) Duties of Administrative Committee. Except as otherwise expressly provided in the Plan, the Administrative Committee shall be responsible for the administration of the Plan, with all powers and discretionary authority necessary to enable the Administrative Committee to carry out its duties in that respect. Not in limitation, but in amplification of the foregoing, the Administrative Committee shall have the following duties, responsibilities and full discretionary authority with respect to the administration of the Plan:

(1) To prescribe procedures and forms to be followed by Participants in filing applications for benefits and for furnishing evidence necessary to establish their rights to benefits under the Plan;

(2) To interpret the Plan, and to resolve ambiguities, inconsistencies and omissions in accordance with the intent of the Plan;

(3) To decide on questions concerning the Plan and the eligibility of an Employee to participate in the Plan, in accordance with the provisions of the Plan;

(4) To make benefit payments directly to Participants and/or their assignees entitled to benefits under the Plan;

(5) To find facts and to grant or deny claims relating to eligibility or the payment or nonpayment of benefits under the Claims Procedure in accordance with Article IV;

(6) To obtain from the Participating Companies, Participants and others, such information as it shall deem to be necessary for the proper administration of the Plan;

(7) To take all steps to properly administer the Plan in accordance with its terms and the requirements of applicable law;

(8) To execute any certificate, instrument or other written direction on behalf of the Plan with respect to the administration of this Plan; and

(9) To appoint such accountants, counsel, specialists, and other persons as it deems necessary or appropriate in connection with the administration of this Plan. In this regard, the Administrative Committee may cause the Company to enter into contracts with third parties if the Administrative Committee determines such contracts are desirable in connection with the administration of the Plan. Such accountants and counsel may, but need not, be accountants and counsel for the Company or an affiliate.

The Administrative Committee shall have no power to add to any benefit not provided under the provisions of the Plan, or to waive or fail to apply any requirement of eligibility for a benefit under the Plan.

No determination of the Administrative Committee for any Participant shall create a basis for retroactive adjustment for any other Participant.

All regulations, procedures, and rules with respect to any of the above-described duties, responsibilities, and authorities shall be promulgated by the Administrative Committee (or its delegate) in its sole discretion, and all such regulations, procedures, and rules shall be conclusive and binding on all persons to the maximum extent permitted by law.

All decisions of the Administrative Committee with respect to the Plan's administration, including, but not limited to, interpretations of the Plan, benefit determinations, claims decisions relating to eligibility, and questions concerning the administration and application of the Plan, shall be made by the Administrative Committee (or its delegate) in its sole discretion, and all such determinations and decisions shall be conclusive and binding on all persons to the maximum extent permitted by law.

(c) Recordkeeping. The Administrative Committee or its delegate shall keep full and complete records of the administration of the Plan. The Administrative Committee or its delegate shall prepare such reports and such information concerning the Plan and the administration thereof by the Administrative Committee (or its delegate) as may be required under the Code or ERISA and the regulations promulgated thereunder.

(d) Inspection of Records. The Administrative Committee or its delegate shall, during normal business hours, make available to each Participant for examination by him at the principal office of the Administrative Committee, a copy of the Plan and such records of the Administrative Committee as may pertain to such Participant. No Participant shall have the right to inquire as to or inspect the accounts or records with respect to other Participants."

VII.

Section 5.8 of the Plan is deleted in its entirety.

VIII.

Section 6.3 of the Plan is amended in its entirety to provide as follows:

"6.3 Amendment and Termination. The Compensation Committee and/or the Benefits Committee, in its settlor capacity, reserves the right at any time to terminate the Plan.

The Compensation Committee reserves the right at any time and from time to time, and retroactively if deemed necessary or appropriate, to modify or amend in whole or in part any or all of the provisions of the Plan. The Benefits Committee shall have the right at any time and from time to time, and retroactively if deemed necessary or appropriate, to modify or amend in whole or in part any or all of the provisions of the Plan, provided such modification or amendment constitutes a non-material amendment. Non-material amendments consist of: (i) changes required by applicable law, (ii) changes (including retroactive changes) necessary to maintain the Plan's qualification status, (iii) modifications of the administrative provisions of the Plan to cause the Plan to operate more efficiently, (iv) changes required as part of the collective bargaining process, and (v) modifications or amendments to incorporate changes provided that such modification or amendment does not materially increase or decrease benefits provided under the Plan. Any amendment or modification to the Plan shall be effective at such date as the Compensation Committee may determine with respect to any amendment adopted by the Compensation Committee and as the Benefits Committee may determine with respect to any non-material amendment adopted by the Benefits Committee.

Decisions regarding the design of the Plan (including any decision to amend or terminate, or to not amend or terminate the Plan) will be made in a settlor capacity and will not be governed by the fiduciary responsibility provisions of the Employee Retirement Income Security Act of 1974, as amended."

IX.

Except as modified herein, the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, the Benefits Committee has caused this Amendment to the Plan to be executed and effective as herein provided.

By: /s/ Alan S. Armstrong
Member of the Benefits Committee

Exhibit 12

The Williams Companies, Inc.
Computation of Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2005	2004	2003	2002	2001
	(Dollars in millions)				
Earnings:					
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	$ 531.3	$ 224.5	$ (62.8)	$ (908.7)	$ 1,148.1
Minority interest in income and preferred returns of consolidated subsidiaries	25.7	21.4	19.4	41.8	71.7
Less: Equity earnings	(65.6)	(49.9)	(20.3)	(73.0)	(22.7)
Income 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	491.4	196.0	(63.7)	(939.9)	1,197.1
Add:					
Fixed charges:					
Interest accrued, including proportionate share from 50% owned investees	684.7	838.5	1,298.3	1,172.4	700.8
Rental expense representative of interest factor	19.2	19.7	26.7	23.8	23.8
Preferred distributions	—	—	47.8	58.1	95.7
Total fixed charges	703.9	858.2	1,372.8	1,254.3	820.3
Distributed income of equity-method investees	107.7	60.5	21.5	81.3	50.9
Less:					
Capitalized interest	(7.2)	(6.7)	(45.5)	(27.3)	(36.9)
Preferred distributions	—	—	(47.8)	(58.1)	(95.7)
Total earnings as adjusted	$ 1,295.8	$ 1,108.0	$ 1,237.3	$ 310.3	$ 1,935.7
Fixed charges	703.9	$ 858.2	$ 1,372.8	$ 1,254.3	$ 820.3
Ratio of earnings to fixed charges	1.84	1.29	(a)	(a)	2.36

(a) Earnings were inadequate to cover fixed charges by $135.5 million and $944.0 million for the years ended December 31, 2003 and 2002, respectively.

Exhibit 21

ENTITY	JURISDICTION
ACCROSERV SRL	Barbados
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, L.L.C.	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
Chacahoula Natural Gas Storage, LLC	Delaware
Choctaw Natural Gas Storage, LLC	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
Energy International Corporation	Pennsylvania
Energy News Live, LLC	Delaware
ESPAGAS USA, Inc.	Delaware
ESPAGAS, S.A. de C.V.	Mexico
F T & T, Inc.	Delaware
Fishhawk Ranch, Inc.	Florida

ENTITY	JURISDICTION
FleetOne Inc.	Delaware
Garrison, L.L.C.	Delaware
Gas Supply, L.L.C.	Delaware
Georgia Strait Crossing Pipeline LP	Utah
Goebel Gathering Company, L.L.C.	Delaware
GSX Canada Limited Partnership	British Columbia
GSX Operating Company, LLC	Delaware
GSX Pipeline, LLC	Delaware
GSX Western Pipeline Company	Delaware
Gulf Liquids Holdings LLC	Delaware
Gulf Liquids New River Project LLC	Delaware
Gulf Star Deepwater Services, LLC	Delaware
Gulf Stream Natural Gas System, L.L.C.	Delaware
Gulfstream Management & Operating Services, 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
Longhorn Partners GP, L.L.C.	Delaware
Longhorn Partners Pipeline, L.P.	Delaware
MAPCO Alaska Inc.	Alaska
MAPCO Energy Services, L.L.C.	Delaware
MAPCO Inc. DE	Delaware
MAPL Investments, Inc.	Delaware
Marsh Resources, Inc.	Delaware
Mid-Continent Fractionation and Storage, LLC	Delaware
Millennium Energy Fund, L.L.C.	Delaware
Moriche Bank Ltd.	Barbados
Northwest Alaskan Pipeline Company	Delaware
Northwest Argentina Corporation	Utah
Northwest Land Company	Delaware
Northwest Pipeline Corporation	Delaware
Opal TXP-4 Company, LLC	Delaware
Overland Pass Pipeline Company, LLC	Delaware
Parkco, L.L.C.	Oklahoma
Parkco Two, L.L.C.	Oklahoma
Piceance Production Holdings LLC	Delaware
Pine Needle LNG Company, LLC	North Carolina
Pine Needle Operating Company	Delaware
Rainbow Resources, Inc.	Colorado
Reserveco Inc.	Delaware
Rio Vista Energy Marketing Company, L.L.C.	Delaware

ENTITY	JURISDICTION
Rulison Production Company LLC	Delaware
Servicios Williams International de Mexico S.A. de C.V.	Mexico
Silver State Resources Management, LLC	Delaware
Snow Goose Associates, L.L.C.	Delaware
Sociedad Williams Enbridge y Compania	Venezuela
Solutions EMT, Inc.	Texas
SPV, L.L.C.	Oklahoma
Tennessee Processing Company	Delaware
TGPL Enterprises, Inc.	Delaware
TGPL Enterprises, LLC	Delaware
The Tennessee Coal Company	Delaware
Thermogas Energy, LLC	Delaware
Touchstar Energy Technologies, Inc.	Texas
Touchstar Technologies Pty Ltd.	South Africa
TouchStar Technologies, L.L.C.	Delaware
TransCardinal Company	Delaware
TransCarolina LNG Company	Delaware
Transco Coal Gas Company	Delaware
Transco Cross Bay Company	Delaware
Transco Energy Company	Delaware
Transco Energy Investment 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 Terminal Company	Delaware
Transco Tower Realty, Inc.	Delaware
Transcontinental Gas Pipe Line Corporation	Delaware
Transeastern Gas Pipeline Company, Inc.	Delaware
Tulsa Williams Company	Delaware
TXG Gas Marketing Company	Delaware
Valley View Coal, Inc.	Tennessee
Volunteer — Williams, L.L.C.	Delaware
WCG NOTE CORP., INC.	Delaware
WEM&T Trading GmbH	Austria
WFS — Liquids Company	Delaware
WFS — NGL Pipeline Company, Inc.	Delaware
WFS — Pipeline Company	Delaware
WFS Enterprises, Inc.	Delaware
WFS Gathering Company, L.L.C.	Delaware
WGP Enterprises, Inc.	Delaware
WGP Gulfstream Pipeline Company, L.L.C.	Delaware
WGP International Canada, Inc.	New Brunswick
WHBC Holdings, LLC	Delaware
WHBC, LLC	Delaware

ENTITY	JURISDICTION
WHD Enterprises, LLC	Delaware
Williams Acquisition Holding Company, Inc. (Del)	Delaware
Williams Acquisition Holding Company, Inc. (NJ)	New Jersey
Williams Aircraft, Inc.	Delaware
Williams Alaska Air Cargo Properties, L.L.C.	Alaska
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 EnergÍa Espana, S.L.	Spain
Williams Energia Italia SRL	Italy
Williams Energy Canada, Inc.	New Brunswick
Williams Energy Company	Delaware
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 Network, Inc.	Delaware
Williams Energy Services, LLC	Delaware
Williams Energy Solutions, Inc.	Delaware
Williams Energy, L.L.C.	Delaware
Williams Environmental Services Company	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 Gas Company	Delaware
Williams Gas Energy, Inc.	Delaware
Williams Gas Pipeline Company, LLC	Delaware
Williams Gas Pipeline Mexico, S.A. de C.V.	Mexico
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 GP LLC	Delaware
Williams GSR, L.L.C.	Delaware

ENTITY	JURISDICTION
Williams Gulf Coast Gathering Company, LLC	Delaware
Williams Headquarters Building Company	Delaware
Williams Headquarters Building, L.L.C.	Delaware
Williams Holdings GmbH	Austria
Williams Hugoton Compression Services, Inc.	Delaware
Williams Indonesia, L.L.C.	Delaware
Williams Information Technology, Inc.	Delaware
Williams International Bermuda Limited	Bermuda
Williams International Company	Delaware
Williams International de Mexico, S.A. de C.V.	Mexico
Williams International Ecuadorian Ventures Bermuda Limited	Bermuda
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 Investments Cayman Limited	Cayman Islands
Williams International Venezuela Limited	Cayman Islands
Williams International Ventures Bermuda Ltd.	Bermuda
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
Williams Natural Gas Liquids Canada, Inc.	Alberta
Williams Natural Gas Liquids, Inc.	Delaware
Williams Natural Gas Storage, LLC	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 Partners GP LLC	Delaware
Williams Partners Holdings LLC	Delaware
Williams Partners, L.P.	Delaware
Williams Partners Operating LLC	Delaware
WILLIAMS PETROLEOS ESPAÑA, S.L.	Spain
Williams Petroleum Pipeline Systems, Inc.	Delaware
Williams Petroleum Services, LLC	Delaware
Williams Pipeline Services Company	Delaware
Williams Power Company, Inc.	Delaware

ENTITY	JURISDICTION
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 Risk Holdings, L.L.C.	Delaware
Williams Risk Management L.L.C.	Delaware
Williams Soda Holdings, LLC	Delaware
Williams Sodium Products Company	Delaware
Williams Strategic Sourcing Company	Delaware
Williams Strategic Ventures, LLC	Delaware
Williams Trading UK Ltd.	United Kingdom
Williams TravelCenters, Inc.	Delaware
Williams Underground Gas Storage Company	Delaware
Williams Western Holding Company, Inc.	Delaware
Williams Wireless, Inc.	Delaware
Williams WPC — I, Inc.	Delaware
Williams WPC — II, Inc.	Delaware
Williams WPC International Company	Delaware
WilMart, Inc.	Delaware
WilPro Energy Services El Furrial Limited	Cayman Islands
WilPro Energy Services Pigap II Limited	Cayman Islands
Worldwide Services Limited	Cayman Islands
WPX Enterprises, Inc.	Delaware
WPX Gas Resources Company	Delaware

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 March 6, 2006, with respect to the consolidated financial statements and schedule of The Williams Companies, Inc., The Williams Companies, Inc. management's assessment of the effectiveness of internal control over financial reporting, 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, 2005:

Form S-3:

Registration Statement Nos. 333-20927, 333-20929, 333-27311, 333-29185, 333-35097, 333-35101, 333-70394, 333-85540, and 333-106504

Form S-4:

Registration Statement Nos. 333-57416, 333-63202, 333-72982, 333-85568, 333-101788, and 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

/s/ Ernst & Young LLP

Tulsa, Oklahoma
March 6, 2006

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 dated as of December 31, 2005, each of which is included in the Annual Report on Form 10-K of The Williams Companies for the year ended December 31, 2005. We also consent to the reference to us under the heading of "Experts" in such Annual Report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Frederic D. Sewell
Frederic D. Sewell
Chairman and Chief Executive Officer

Dallas, Texas
February 16, 2006

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, 2005, 2004, and 2003, each of which is included in the Annual Report on Form 10-K of The Williams Companies for the year ended December 31, 2005. 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 16, 2006

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, 2005, 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 27th day of January, 2006.

/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/ Irl F. Engelhardt Irl F. Engelhardt Director	/s/ William R. Granberry William R. Granberry Director
/s/ William E. Green William E. Green Director	/s/ Juanita H. Hinshaw Juanita H. Hinshaw Director
/s/ W. R. Howell W. R. Howell Director	/s/ Charles M. Lillis Charles M. Lillis Director
/s/ George A. Lorch George A. Lorch Director	/s/ William G. Lowrie William G. Lowrie Director
/s/ Frank T. MacInnis Frank T. MacInnis Director	/s/ Janice D. Stoney Janice D. Stoney Director

/s/ Joseph H. Williams
Joseph H. Williams
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 27, 2006, 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, 2005.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the corporate seal of The Williams Companies, Inc. this 27th day of January, 2006.

/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: March 9, 2006

/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: March 9, 2006

/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, 2005 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
March 9, 2006

/s/ Donald R. Chappel
Donald R. Chappel
Chief Financial Officer
March 9, 2006

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.