Williams' Redwater fractionator near Edmonton, Alberta, is part of Williams' growing presence in Canada.

2010 Annual Report

The Williams Companies, Inc.

Ingenuity takes energy.

Williams.

Financial Highlights

Dollars in millions, except per-share amounts

	2010	2009	2008	2007	2006
Revenues	**$9,616**	$8,255	$ 11,890	$10,239	$ 9,144
Income (loss) from continuing operations[1]	**(916)**	584	1,467	910	366
Income (loss) from discontinued operations[2]	**(6)**	(223)	125	170	(17)
Amounts attributable to The Williams Companies, Inc.:					
Income (loss) from continuing operations	**(1,091)**	438	1,306	829	332
Income (loss) from discontinued operations	**(6)**	(153)	112	161	(23)
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	**(1.87)**	.75	2.21	1.37	.55
Income (loss) from discontinued operations	**(0.01)**	(0.26)	0.19	0.26	(0.04)
Total assets at December 31	**24,972**	25,280	26,006	25,061	25,402
Short-term notes payable and long-term debt due within one year at December 31	**508**	17	18	108	358
Long-term debt at December 31	**8,600**	8,259	7,683	7,580	7,410
Stockholders' equity at December 31	**7,288**	8,447	8,440	6,375	6,073
Cash dividends declared per common share	**0.485**	.44	.43	.39	.345

[1] Loss from continuing operations for 2010 includes $648 million of pre-tax costs associated with our restructuring, as well as approximately $1.7 billion of impairment charges related to goodwill and certain properties at Exploration & Production. See Note 4 of Notes to Consolidated Financial Statements for further discussion of asset sales, impairments, and other accruals in 2010, 2009, and 2008. Income from continuing operations for 2006 includes a $73 million charge for a litigation contingency and a $167 million charge for a securities litigation settlement and related costs.

[2] See Note 2 of Notes to Consolidated Financial Statements for the analysis of the 2010, 2009, and 2008 income (loss) from discontinued operations. The discontinued operations results for 2007 include our former power business and our discontinued Venezuela operations. The discontinued operations results for 2006 include our former power business, discontinued Venezuela operations, as well as amounts associated with our former chemical fertilizer business, a former exploration business, our former Alaska refinery, and our former distributive power business.

On the Cover: *The Redwater fractionator is part of Williams' oil sands off-gas processing operations in Canada. Williams pioneered the process, which extracts valuable natural gas liquids (NGLs) from the off-gas that is produced when oil sands are converted to usable crude oil. In addition to creating valuable NGL feedstock for the petrochemical industry, Williams' operations reduce emissions of carbon dioxide and sulfur dioxide in Alberta by approximately 200,000 tons and 4,200 tons each year, respectively.*

Forward-Looking Statements: *Certain matters discussed in this report, except historical information, include forward-looking statements. Although Williams believes such statements are based on reasonable assumptions, no assurance can be given that every objective will be achieved. For more detail, see page 21 of the Form 10-K in the back of this report.*

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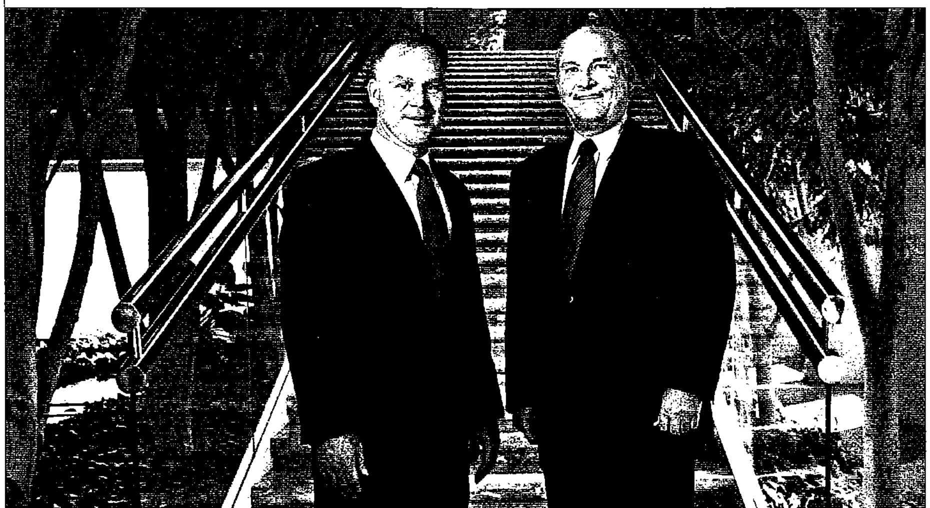


From left, President and Chief Executive Officer Alan Armstrong and Chairman Frank MacInnis

Dear fellow Williams shareholders,

It's our pleasure to write you for the first time as chairman and CEO, respectively, of Williams. We sincerely appreciate the strong leadership and dedicated service of Steve Malcolm, who retired as chairman, president and CEO in January.

We're truly excited to be leading Williams right now – at a time when natural gas is poised to be a transformative force in the U.S. energy picture. Natural gas is a clean, abundant and domestic energy resource that will help reduce dependence on foreign oil and also create jobs in communities across the country. It's an important resource for not only heating, power generation and transportation, but also as a feedstock to the multi-billion-dollar U.S. petrochemical industry.

Williams will play a big part in creating the infrastructure that will be required to bring these crucial supplies to markets. We have premier assets in growing new resource plays backed up by a tremendously knowledgeable and experienced workforce. There's more on those growth opportunities below.

Looking at recent developments at Williams, we began this year much in the same way we began 2010 – by announcing a major change to the company's structure intended to increase the value of our businesses.

On Feb. 16, we announced a plan to pursue separation of our exploration and production business, creating two publicly owned companies with better defined business and investment profiles. One company, still known as Williams, will focus primarily on large-scale infrastructure in the midstream, gas pipeline and olefins businesses. The new company will be a diversified, independent exploration and production company.

"During 2010, we accomplished several strategic expansions while initiating others. In fact, we invested nearly $4.4 billion in capital last year, including more than $2 billion in acquisitions."

Under the first step of this plan, an initial public offering of up to 20 percent of the new exploration and production company will be conducted later this year. At that point, Williams would continue to own at least 80 percent of the new company. Then, in 2012, we plan to fully separate the companies through a tax-free spinoff to Williams shareholders of the remaining interest.

This decision by Williams' board and executive management team follows a long run of success under the integrated natural gas model. However, market expectations have changed, as has the industry itself. Many of you have expressed a strong preference to see the company spin off Exploration & Production so that it may be evaluated by the market in a manner comparable to its pure-play peers. Once the spinoff is complete, we believe both the growth potential and overall shareholder valuation of our assets will be enhanced.

As part of this announcement, we also revealed plans to increase our quarterly dividend by 60 percent beginning with the first quarter of 2011, payable in June, with an additional 10 to 15 percent increase planned for June 2012. With this decision, along with our strong growth outlook, we intend to make Williams an even more attractive source of long-term returns for our shareholders.

Shareholder value and enhanced growth prospects also drove the restructuring announcement that began 2010. Under that restructuring, we dropped most of our gas pipeline and midstream assets down to Williams Partners, the master limited partnership in which we hold the general partner and majority limited-partner interest. The $12 billion transaction, which was largely completed in the first quarter of last year, left Williams owning a significantly increased portion of Williams Partners. And in a separate transaction in November, Williams completed a dropdown of the Piceance Basin gathering and treating assets to Williams Partners.

During 2010, we accomplished several strategic expansions while initiating others. In fact, we invested nearly $4.4 billion in capital last year, including more than $2 billion in acquisitions. The biggest of these, our $925 million acquisition in North Dakota's Bakken Shale oil play, serves to diversify our exploration and production business, both in terms of geography and commodity segment.

We are rapidly building a large-scale presence in the Marcellus Shale, where we've invested more than $1 billion since 2009. In 2010, we bolstered this position with Williams Partners' $150 million acquisition of gathering assets in Susquehanna County, Pa. In addition, our exploration and production business has established a position of approximately 100,000 acres in Pennsylvania. We also continue to invest in our growing olefins and Canadian midstream business, as we're in the process of building a 261-mile NGL/olefins pipeline from our Fort McMurray facility to our fractionator near Edmonton in Alberta, Canada. We expect all of these investments to contribute to the earnings growth we've projected in our guidance over the next two years, which includes another $4 billion in capital expenditures.

Looking ahead, several factors point to an unmistakable need for new natural gas infrastructure. The domestic shale plays are rich sources of natural gas and they're developing rapidly. These new supplies require gathering, processing and transportation capacity in areas where infrastructure is inadequate. In addition, demand for natural gas liquids is rising in the petrochemical industry, which is looking for reliable supplies of low-cost feedstock.

Geopolitical, economic and environmental realities also make a strong case for natural gas. As the United States reckons with a rapidly changing political landscape in the Middle East, it's becoming ever more apparent that stable, long-term supplies of domestic energy are critical to national security. But it's not just about security. Even assuming that prices rebound over the next few years, natural gas still will be a far more cost-effective and reliable fuel source than most other viable alternatives. Just as important are the significant environmental advantages of natural gas, which is the cleanest burning fossil fuel.

In order for us to fully realize the potential of this great resource, one thing that is needed is clear, consistent regulations across the board. In many areas, development can be hampered because of unclear or even contradictory regulations at the state and/or local levels. We believe that a clear and consistent set of regulations would create the best environment to realize the potential of our vast natural gas resources.

In pursuing the enormous opportunities presented by the growing demand for energy infrastructure, we acknowledge and accept our obligation to do so responsibly. Being a good steward to the environment and a good neighbor to our communities is a responsibility we take to heart. We don't do these things because that's what is expected of us. We do them because they're the right thing to do. That's why we work every day to forge meaningful partnerships with landowners, community leaders, regulators and non-governmental agencies in the areas where we operate. And when we do sit down with our stakeholders, we do so, first and foremost, to engage in mutually beneficial relationships that create trust over the long term.

It's an exciting time for our company as we embark on another transformative milestone in our 103-year history. We hope you share our excitement. Thank you for your continued support and confidence.

Frank T. MacInnis
Chairman

Alan S. Armstrong
President and Chief Executive Officer

March 31, 2011

"Being a good steward to the environment and a good neighbor to our communities is a responsibility we take to heart. We don't do these things because that's what is expected of us. We do them because they're the right thing to do."

Williams Partners

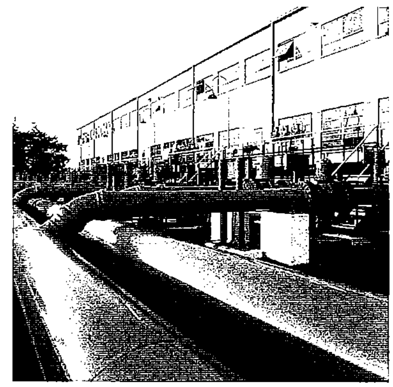
Overview

- Segment includes consolidated results of Williams Partners L.P. (NYSE: WPZ), which is 75 percent owned by Williams as of Dec. 31, 2010, including 2 percent general partner interest
- Gathers, treats and processes natural gas
- Transports deepwater natural gas and oil production
- Produces, fractionates, stores and transports natural gas liquids
- Owns and operates approximately 13,900 miles of interstate gas transmission pipelines with 2.8 Tcf of total annual throughput and 13 million dekatherms of peak-day delivery capacity
- Delivers 12 percent of natural gas consumed in the United States

2010 Highlights

- Gas Pipeline business
  - Completed the Sundance Trail expansion on our Northwest Pipeline system, adding 150,000 dekatherms per day of capacity
  - Received Federal Energy Regulatory Commission approval to expand service on the Transco system in the Southeast
  - Set a peak-day throughput record on Transco, which transported 9.52 million dekatherms on Jan. 3, enough to heat 40 million homes
- Midstream business
  - Added to the growing footprint in the Marcellus Shale with $150 million acquisition of gathering assets in Susquehanna County, Pa.
  - Continued construction on the 33-mile Springville natural gas gathering pipeline, connecting our northeastern Pennsylvania gathering assets to our Transco interstate pipeline
  - Developed plans to expand gathering systems in northeastern and southwestern Pennsylvania

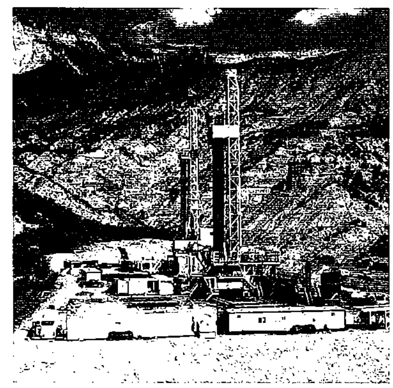
- Expanded the Echo Springs processing plant in Wyoming by adding a fourth cryogenic processing train, boosting capacity by 350 MMcf/d and 30,000 barrels per day of natural gas liquid production
- Made a significant investment in critical NGL transportation out of the Rockies by increasing ownership of Overland Pass Pipeline Company to 50 percent



Exploration and Production

Overview

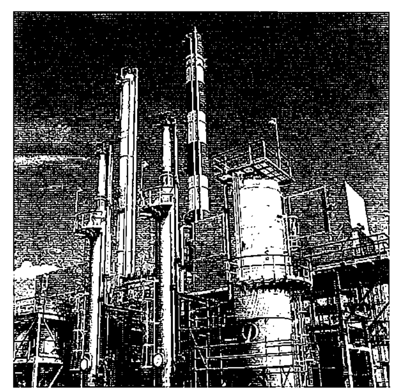
- Produces, develops, and markets oil and gas reserves primarily in the Rockies, Midcontinent and Northeast
- Specializes in natural gas and oil production from tight-sands and shale formations and coal bed methane reserves in the Marcellus Shale, Piceance Basin, Bakken Shale, Powder River, San Juan Basin and Barnett Shale
- Holds 69 percent equity interest in Apco Oil and Gas International Inc.



2010 Highlights

- Completed multiple acquisitions in the Marcellus Shale, increasing the company's position to approximately 100,000 net acres
- Also completed $925 million acquisition of more than 85,000 lease acres in the Bakken Shale of North Dakota, representing an estimated 185 million barrels of oil
- Total proved reserves at 4.5 trillion cubic feet equivalent (Tcfe)
- Replaced 107% of total net proved reserves

Other



Overview

- Ethylene production from ethane cracker
- Propylene production from refinery-grade propylene splitter
- Extraction, fractionation and transportation of NGLs and olefins from the off-gas of oil sand bitumen upgrading process
- Concentrated in the Gulf of Mexico and Canada

2010 Highlights

- Higher NGL and olefin margins drove improved results
- Placed into service a new butylene/butane splitter and hydro-treating facility in Alberta, Canada
- Began constructing a 12-inch pipeline in Alberta, Canada, to transport recovered NGLs and olefins from our extraction plant in Fort McMurray to our Redwater fractionation facility

DIRECTORS

ALAN S. ARMSTRONG, 48
Tulsa, Okla.
Director, president and
chief executive officer, Williams.
Director since 2011.

JOSEPH R. CLEVELAND, 66
Orlando, Fla.
Former chief information officer,
Lockheed Martin Corporation.
Director since 2008.

KATHLEEN B. COOPER, 66
Dallas, Texas
Senior fellow, Tower Center for Political
Studies, Southern Methodist University.
Director since 2006.

IRL F. ENGELHARDT, 64
St. Louis, Mo.
Chairman, Patriot Coal Corporation.
Director since 2005.

WILLIAM R. GRANBERRY, 68
Midland, Texas
Member, Compass
Operating Company LLC.
Director since 2005.

WILLIAM E. GREEN, 74
Palo Alto, Calif.
Founder, William Green & Associates.
Director since 1998.

JUANITA H. HINSHAW, 66
St. Louis, Mo.
President and chief executive
officer, H&H Advisors.
Director since 2004.

W. R. HOWELL, 75
Wilson, Wyo.
Chairman emeritus,
J.C. Penney Company, Inc.
Director since 1997.

GEORGE A. LORCH, 69
Naples, Fla.
Chairman emeritus,
Armstrong Holdings, Inc.
Director since 2001.

WILLIAM G. LOWRIE, 67
Sheldon, S.C.
Former deputy chief executive
officer, BP Amoco PLC.
Director since 2003.

FRANK T. MACINNIS, 64
Norwalk, Conn.
Chairman of the board, Williams.
Director since 1998.

JANICE D. STONEY, 70
Omaha, Neb.
Former executive vice president,
U S WEST Communications Group, Inc.
Director since 1999.

LAURA A. SUGG, 50
Katy, Texas
Former president,
Conoco Phillips Australasia Division
Director since 2010.

HONORARY DIRECTORS

JOHN H. WILLIAMS, 92
Tulsa, Okla.
Co-founder of Williams Brothers
Company in 1949. President and
chief executive officer for Williams
from 1949-79; chairman and chief
executive officer from 1971-79.
Elected to the board in 1949.

JOSEPH H. WILLIAMS, 77
Tulsa, Okla.
Chairman and chief executive
officer for Williams from 1979-1994.
Elected to the board in 1969.

SENIOR OFFICERS

ALAN S. ARMSTRONG
Director, president and
chief executive officer

RANDY L. BARNARD
Senior vice president,
Gas Pipeline

JAMES J. BENDER
Senior vice president and
general counsel

DONALD R. CHAPPEL
Senior vice president and
chief financial officer

ROBYN L. EWING
Senior vice president and
chief administrative officer

RALPH A. HILL
Senior vice president,
Exploration & Production

RORY L. MILLER
Senior vice president,
Midstream Gathering & Processing

PHILLIP D. WRIGHT
Senior vice president,
Corporate Development

BOARD COMMITTEES

Audit Committee

Joseph R. Cleveland
Irl F. Engelhardt
William E. Green
Juanita H. Hinshaw
William G. Lowrie (Chair)

Compensation Committee

Kathleen B. Cooper
William R. Granberry
W. R. Howell
George A. Lorch
Frank T. MacInnis
Janice D. Stoney (Chair)
Laura A. Sugg

Finance Committee

Joseph R. Cleveland
Kathleen B. Cooper
Irl F. Engelhardt
William R. Granberry
Juanita H. Hinshaw (Chair)
Laura A. Sugg

Nominating & Governance Committee

William E. Green
W. R. Howell
George A. Lorch
William G. Lowrie
Frank T. MacInnis (Chair)
Janice D. Stoney

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 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, 2010

or

☐ **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
Preferred Stock Purchase Rights	New York Stock Exchange

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

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

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 ☐ 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 ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ 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 $10,683,141,499.

The number of shares outstanding of the registrant's common stock outstanding at February 21, 2011 was 586,207,919.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Definitive Proxy Statement for the Registrant's 2011 Annual Meeting of Stockholders to be held on May 19, 2011, are incorporated into Part III, as specifically set forth in 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:

Barrel — means one barrel of petroleum products that equals 42 U.S. gallons.

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

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

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

BBtud — means one billion BTUs per day.

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

Mbbls/d — means one thousand barrels per day.

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

Mdt/d — means one thousand dekatherms per day.

MMboe — means one million barrels of oil equivalent.

MMBtu — means one million Btus.

MMBtu/d — means one million Btus per day.

MMcf — means one million cubic feet.

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

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

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

MMdt/d — means one million dekatherms per day.

TBtu — means one trillion BTUs.

Other definitions:

FERC — means Federal Energy Regulatory Commission.

Fractionation — means the process by which a mixed stream of natural gas liquids is separated into its constituent products, such as ethane, propane and butane.

LNG — means liquefied natural gas; natural gas which has been liquefied at cryogenic temperatures.

NGL — means natural gas liquids; natural gas liquids result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels and gasoline additives, among other applications.

NGL margins — means NGL revenues less Btu replacement cost, plant fuel, transportation and fractionation.

Throughput — means the volume of product transported or passing through a pipeline, plant, terminal or other facility.

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 100 F Street, N.E., 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 through the Investor tab of 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 for Senior Officers, Board committee charters and the Williams 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 Corporate Secretary, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172.

GENERAL

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

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

CHANGE IN STRUCTURE AND DIVIDEND INCREASE

On February 16, 2011, we announced that our Board of Directors approved pursuing a plan to separate the company into two standalone, publicly traded corporations. The plan calls for the separation of our exploration and production business into a publicly traded company via an initial public offering of up to 20 percent of our interest in the third quarter of 2011. We intend to complete the offering so that it preserves our ability to complete a tax-free spinoff of our remaining ownership in the exploration and production business to Williams' shareholders in 2012, after which Williams would continue as a premier natural gas infrastructure company. We retain the discretion to determine whether and when to execute the spinoff.

Additionally, we intend to increase the quarterly dividend paid to our shareholders, with an initial increase of 60 percent (to $0.20 per share), for the first quarter of 2011 payable in June 2011.

Management believes these actions will serve to enhance the growth potential and overall valuation of our assets.

FINANCIAL INFORMATION ABOUT SEGMENTS

See "*Item 8 — Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements — Note 18*" 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 in 2010 were primarily operated through the following business segments:

- *Williams Partners* — comprised of our master limited partnership Williams Partners L.P. (WPZ), which includes gas pipeline and domestic midstream businesses. The gas pipeline business includes interstate natural gas pipelines and pipeline joint venture investments, and the midstream business provides natural gas gathering, treating and processing services; NGL production, fractionation, storage, marketing and transportation; deepwater production handling and crude oil transportation services and is comprised of several wholly owned and partially owned subsidiaries and joint venture investments.
- *Exploration & Production* — produces, develops, and manages natural gas and oil primarily located in the Rocky Mountain, Northeast 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, LLC. This segment also includes our 69 percent equity interest in Apco Oil and Gas International Inc., as well as gas marketing services which manage our natural gas commodity risk through purchases, sales and other related transactions, under our wholly owned subsidiary Williams Gas Marketing, Inc.
- *Other* — includes other business activities that are not operating segments, primarily our Canadian midstream and domestic olefins operations and a 25.5 percent interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream), as well as corporate operations.

This report is organized to reflect this structure.

Due to expected future growth in our Canadian midstream and domestic olefins operations, we are considering reporting these businesses as a separate segment beginning in the first quarter of 2011.

Detailed discussion of each of our business segments follows.

Williams Partners

Gas Pipeline Business

Williams Partners owns and operates a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,800 TBtu of natural gas and peak-day delivery capacity of approximately 13 MMdt of natural gas. Our gas pipeline businesses consist primarily of Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline GP (Northwest Pipeline). Our gas pipeline business also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5 percent interest in Gulfstream. The gas pipeline businesses contributed revenues of approximately 28 percent, 35 percent and 28 percent of Williams Partners' revenues in 2010, 2009, and 2008, respectively. During third quarter 2010, Williams Partners L.P. completed a merger with Williams Pipeline Partners L.P. (WMZ). All of WMZ's common and subordinated units have been extinguished and WMZ is wholly owned by Williams Partners. WMZ has been delisted and is no longer publicly traded.

Transco

Transco is an interstate natural gas transportation company that owns and operates a 10,000-mile natural gas pipeline system extending from Texas, Louisiana, Mississippi and the offshore Gulf of Mexico through Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 11 southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, Washington, D.C., New York, New Jersey and Pennsylvania.

Pipeline system and customers

At December 31, 2010, Transco's system had a mainline delivery capacity of approximately 4.9 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 3.9 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.8 MMdt of natural gas per day. Transco's system includes 45 compressor stations, four underground storage fields, and an LNG storage facility. Compression facilities at 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. 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 four underground storage fields located on or near its pipeline system or market areas and operates two of these storage fields. Transco also has storage capacity in an LNG storage facility that it owns and operates. 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 200 billion cubic feet of gas. At December 31, 2010, our customers had stored in our facilities approximately 154 Bcf of natural gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent ownership interest in Pine Needle LNG Company, LLC, a LNG storage facility with 4 billion cubic feet of storage capacity. Storage capacity permits Transco's customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Transco expansion projects

The pipeline projects listed below were completed during 2010 or are future significant pipeline projects for which Transco has customer commitments.

Mobile Bay South

The Mobile Bay South Expansion Project involved the addition of compression at Transco's Station 85 in Choctaw County, Alabama, to allow Transco to provide firm transportation service southbound on the Mobile Bay line from Station 85 to various delivery points. In May 2009, Transco received approval from the Federal Energy Regulatory Commission (FERC). The capital cost of the project was $32 million. The project was placed into service in May 2010 and increased capacity by 254 Mdt/d.

Mobile Bay South II

The Mobile Bay South II Expansion Project involves the addition of compression at Transco's Station 85 in Choctaw County, Alabama, and modifications to existing facilities at Transco's Station 83 in Mobile County, Alabama, to allow Transco to provide additional firm transportation service southbound on the Mobile Bay line from Station 85 to various delivery points. In July 2010 Transco received approval from the FERC. The capital cost of the project is estimated to be approximately $35 million, and it will increase capacity by 380 Mdt/d. Transco plans to place the project into service by May 2011.

85 North

The 85 North Expansion Project involves an expansion of Transco's existing natural gas transmission system from Station 85 in Choctaw County, Alabama, to various delivery points as far north as North Carolina. In September 2009, Transco received approval from the FERC. The capital cost of the project is estimated to be approximately $236 million, and it will increase capacity by 309 Mdt/d. The first phase for 90 Mdt/d, was placed into service in July 2010, and the second phase is expected to be placed into service in May 2011.

Mid-South

The Mid-South Expansion Project involves an expansion of Transco's mainline from Station 85 in Choctaw County, Alabama, to markets as far downstream as North Carolina. In October 2010 Transco filed an application with the FERC. The capital cost of the project is estimated to be approximately $219 million. Transco plans to place the project into service in phases in September 2012 and June 2013, and it will increase capacity by 225 Mdt/d.

Mid-Atlantic Connector Project

The Mid-Atlantic Connector Project involves an expansion of Transco's mainline from an existing interconnection in North Carolina to markets as far downstream as Maryland. In November 2010 Transco filed an application with the FERC. The capital cost of the project is estimated to be approximately $55 million. Transco plans to place the project into service in November 2012, and it will increase capacity by 142 Mdt/d.

Rockaway Delivery Lateral Project

The Rockaway Delivery Lateral Project involves the construction of a three-mile offshore lateral to a distribution system in New York. Transco anticipates filing an application with the FERC in the fourth quarter of 2011. The capital cost of the project is estimated to be approximately $159 million. Transco plans to place the project into service as early as November 2013, and its capacity will be 647 Mdt/d.

Northeast Supply Link Project

The Northeast Supply Link Project involves an expansion of Transco's existing natural gas transmission system from the Marcellus Shale production region on the Leidy Line to various delivery points in New York and New Jersey. Transco anticipates filing an application with the FERC in the fourth quarter of 2011. The capital cost of the project is estimated to be approximately $341 million. Transco plans to place the project into service in November 2013, and it will increase capacity by 250 Mdt/d.

Northwest Pipeline

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

Pipeline system and customers

At December 31, 2010, Northwest Pipeline's system, having long-term firm transportation agreements including peaking service of approximately 3.8 Bcf of natural gas per day, was composed of approximately 3,900 miles of mainline and lateral transmission pipelines and 41 transmission compressor stations having a combined sea level-rated capacity of approximately 477,000 horsepower.

Northwest Pipeline transports and stores natural gas for a broad mix of customers, including local natural gas distribution companies, municipal utilities, direct industrial users, electric power generators and natural gas marketers and producers. Northwest Pipeline's firm transportation and storage contracts are generally long-term contracts 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.

Northwest Pipeline owns a one-third interest in the Jackson Prairie underground storage facility in Washington and contracts with a third party for storage service in the Clay basin underground field in Utah. Northwest Pipeline also owns and operates an LNG storage facility in Washington. These storage facilities have an aggregate working gas storage capacity of 13.2 Bcf of natural gas, which is substantially utilized for third-party natural gas, and firm delivery capability of approximately 700 MMcf/d enable Northwest Pipeline to provide storage services to its customers and to balance daily receipts and deliveries.

Northwest Pipeline expansion project

Sundance Trail

In November 2009, we received approval from the FERC to construct approximately 16 miles of 30-inch pipeline between our existing compressor stations in Wyoming as well as an upgrade to an existing Vernal, Utah compressor station. The total estimated cost of the project is approximately $50 million. We placed the project in service in November 2010 with an increase in capacity of 150 Mdt/d.

Gulfstream

Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida. Williams Partners owns, through a subsidiary, a 24.5 percent interest in Gulfstream while we own a 25.5 percent interest through a subsidiary. Spectra Energy Corporation, through its subsidiary, and Spectra Energy Partners, LP, own the additional 50 percent interest. Williams Partners shares operating responsibilities for Gulfstream with Spectra Energy Corporation.

Gulfstream expansion projects

The Gulfstream Phase V expansion involves the addition of compression to provide 35 Mdt/d of firm capacity by April 2011. The estimated capital cost of this expansion is approximately $44 million with Williams Partners' share being 24.5 percent of such cost.

Midstream Business

Williams Partners' midstream business, one of the nation's largest natural gas gatherers and processors, has primary service areas concentrated in major producing basins in Colorado, New Mexico, Wyoming, the Gulf of Mexico and Pennsylvania. The primary businesses — natural gas gathering, treating, and processing; NGL fractionation, storage and transportation; and oil transportation — fall within the middle of the process of taking raw natural gas and crude oil from the producing fields to the consumer.

Key variables for this business will continue to be:

- Retaining and attracting customers by continuing to provide reliable services;
- Revenue growth associated with additional infrastructure either completed or currently under construction;
- Disciplined growth in core service areas and new step-out areas;
- Prices impacting commodity-based processing activities.

The midstream business revenue contributed approximately 72 percent, 66 percent and 72 percent of Williams Partners' revenues in 2010, 2009 and 2008, respectively.

One of our midstream customers, ONEOK Hydrocarbon LP, accounted for 10 percent of our consolidated revenues in 2010. These revenues were generated by our NGL marketing business. There were no customers for which our sales exceeded 10 percent of our consolidated revenues in 2009 and 2008.

Gathering, processing and treating

Williams Partners' gathering systems receive natural gas from producers' oil and natural gas wells and gather these volumes to gas processing, treating or redelivery facilities. Typically, natural gas, in its raw form, is not acceptable for transportation in major interstate natural gas pipelines or for commercial use as a fuel. In addition, natural gas contains various amounts of NGLs, which generally have a higher value when separated from the natural gas stream. Processing and treating plants remove water vapor, carbon dioxide and other contaminants and extract the NGLs. NGL products include:

- Ethane, primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for plastics;
- Propane, used for heating, fuel and as a petrochemical feedstock in the production of ethylene and propylene, another building block for petrochemical-based products such as carpets, packing materials and molded plastic parts;
- Normal butane, iso-butane and natural gasoline, primarily used by the refining industry as blending stocks for motor gasoline or as a petrochemical feedstock.

Although a significant portion of Williams Partners' gas processing services are performed for a volumetric-based fee, a portion of our gas processing agreements are commodity-based and include two distinct types of commodity exposure. The first type includes "keep-whole" processing agreements whereby we own the rights to the value from NGLs recovered at our plants and we have the obligation to replace the lost heating value with natural gas. Under these agreements, we are exposed to the spread between NGL prices and natural gas prices. The second type consists of "percent-of-liquids" agreements whereby we receive a portion of the extracted liquids with no direct exposure to the price of natural gas. Under these agreements, we are only exposed to NGL price movements. NGLs we retain in connection with both of these types of processing agreements are referred to as our equity NGL production. Our gathering and processing agreements have terms ranging from month-to-month to the life of the producing lease. Generally, our gathering and processing agreements are long-term agreements.

Williams Partners' gas gathering and processing customers are generally natural gas producers who have proved and/or producing natural gas fields in the areas surrounding its infrastructure. During 2010, these operations gathered and processed gas for approximately 215 gas gathering and processing customers. Williams Partners' top 6 gathering and processing customers, one of which is an affiliate, accounted for approximately 50 percent of our gathering and processing revenue.

In addition to natural gas assets, Williams Partners owns and operates four deepwater crude oil pipelines and owns two production platforms serving the deepwater in the Gulf of Mexico. The crude oil transportation revenues are typically volumetric-based fee arrangements. However, a portion of its marketing revenues are recognized from purchase and sale arrangements whereby the oil that Williams Partners transports is purchased and sold as a function of the same index-based price. Williams Partners' offshore floating production platforms provide centralized services to deepwater producers such as compression, separation, production handling, water removal and pipeline landings. Revenue sources have historically included a combination of fixed-fee, volumetric-based fee and cost reimbursement arrangements. Fixed fees associated with the resident production at our Devils Tower facility are recognized on a units-of-production basis.

Geographically, the midstream natural gas assets are positioned to maximize commercial and operational synergies with our other assets. For example, most of the offshore gathering and processing assets attach and process or condition natural gas supplies delivered to the Transco pipeline. Also, the gathering and processing facilities in the San Juan and Piceance basins handle approximately 92 percent of our Exploration & Production segment's equity production in these basins. The San Juan basin, southwest Wyoming and Willow Creek systems deliver residue gas volumes into Northwest Pipeline's interstate system in addition to third-party interstate systems.

Onshore region gathering, processing and treating

Williams Partners owns and/or operates gas gathering, processing and treating assets within the states of Wyoming, Colorado, New Mexico and Pennsylvania.

In the Rocky Mountain area, the assets include:

- Approximately 3,500 miles of gathering pipelines with a capacity of nearly 1 Bcf/d and over 4,000 receipt points serving the Wamsutter and southwest Wyoming areas in Wyoming;

- Opal and Echo Springs processing plants with a combined daily inlet capacity of over 2.2 Bcf/d and NGL processing capacity of nearly 125 Mbbls/d, including the addition of a fourth cryogenic processing train at the Echo Springs plant which began processing in the fourth quarter of 2010.

In the Four Corners area, the assets include:

- Approximately 3,800 miles of gathering pipelines with a capacity of nearly 2 Bcf/d and approximately 6,500 receipt points serving the San Juan basin in New Mexico and Colorado;

- Ignacio, Kutz and Lybrook processing plants with a combined daily inlet capacity of 765 MMcf/d and NGL processing capacity of approximately 40 Mbbls/d. The Ignacio plant also has the capacity to produce slightly more than 1 Mbbls/d of liquefied natural gas (LNG);

- Milagro and Esperanza natural gas treating plants, which remove carbon dioxide but do not extract NGLs, with a combined daily inlet capacity of 750 MMcf/d. At our Milagro facility, we also use gas-driven turbines to produce approximately 60 mega-watts per day of electricity which we primarily sell into the local electrical grid.

In the Piceance basin in Colorado, the assets include:

- The Willow Creek processing plant, a 450 MMcf/d cryogenic natural gas processing plant in western Colorado's Piceance basin, designed to recover 30 Mbbls/d of NGLs. The plant is currently operating at its designed inlet capacity. In the current processing arrangement with our Exploration & Production segment, Williams Partners receives a volumetric-based processing fee and a percent of the NGLs extracted.

- Approximately 150 miles of gathering pipeline and the Parachute Plant Complex along with three other treating facilities with a combined processing capacity of 1.2 Bcf/d, acquired in the fourth quarter of 2010 from Exploration & Production.

- Parachute Lateral, a 38-mile, 30-inch diameter line transporting gas from the Parachute area to the Greasewood hub and White River hub in northwest Colorado. The Willow Creek plant processes gas flowing through the Parachute Lateral.

- PGX pipeline delivering NGLs from our Exploration & Production segment's existing Parachute area processing plants to a major NGL transportation pipeline system.

In the Appalachian basin in Pennsylvania, the assets include:

- Approximately 75 miles of gathering pipelines and two compressor stations in Susquehanna County, Pennsylvania in the Marcellus Shale, acquired in the fourth quarter of 2010. Williams Partners has agreed to a new long-term dedicated gathering agreement with the seller for its production in the northeast Pennsylvania area of the Marcellus Shale. The acquired system will connect into the Transco pipeline with our 33-mile, 24-inch diameter Springville gathering pipeline. Construction on the Springville pipeline is expected to begin in the first quarter of 2011 and be completed during 2011.

Gulf region gathering, processing and treating

Williams Partners' owns and/or operates gas gathering and processing assets and crude oil pipelines primarily within the onshore and offshore shelf and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi, and Alabama. This includes:

- Nearly 800 miles of onshore and offshore natural gas gathering pipelines with a combined capacity of approximately 3.7 Bcf/d, including:
  - The 115-mile deepwater Seahawk gas pipeline in the western Gulf of Mexico, flowing into the Markham processing plant and serving the Boomvang and Nansen field areas;

- The 105-mile deepwater Perdido Norte gas pipeline in the western Gulf of Mexico, which began transporting gas in the third quarter of 2010 from a third-party producers' floating production facility in to the Seahawk gathering system, which flows into Williams Partners' Markham processing plant;
- The 139-mile Canyon Chief gas pipeline, including the Blind Faith extension in the eastern Gulf of Mexico, flowing into the Mobile Bay processing plant and serving the Devils Tower, Triton, Goldfinger, Bass Lite and Blind Faith fields;

- Mobile Bay and Markham processing plants with a combined daily inlet capacity of 1.2 Bcf/d and NGL handling capacity of 75 Mbbls/d, including the 2010 expansion of the Markham plant to accommodate production volumes from the Perdido Norte gas pipeline;
- Canyon Station production platform, which brings natural gas to specifications allowable by major interstate pipelines but does not extract NGLs, with a daily inlet capacity of 500 MMcf/d;
- Four deepwater crude oil pipelines with a combined length of nearly 400 miles and capacity of 475 Mbbls/d including:
  - BANJO pipeline running parallel to the Seahawk gas pipeline delivering production from two producer-owned spar-type floating production systems; and delivering production to the shallow-water platform at Galveston Area Block A244 (GA-A244) and then onshore through the Hoover Offshore Oil Pipeline System (HOOPS);
  - Perdido Norte pipeline running parallel to the Perdido Norte gas pipeline which began transporting oil in the third quarter of 2010 from a third-party producers' floating production facility and then onshore through HOOPS;
  - Alpine pipeline in the central Gulf of Mexico, serving the Gunnison field, and delivering production to GA-A244 and then onshore through HOOPS under a joint tariff agreement;
  - Mountaineer pipeline, including the Blind Faith extension, which connects to similar production sources as our Canyon Chief pipeline, ultimately delivering production to a terminal in Plaquemines Parish, Louisiana;
- Devils Tower production platform located in Mississippi Canyon Block 773, approximately 150 miles south-southwest of Mobile, Alabama and serving production from the Devils Tower, Triton, Goldfinger and Bass Lite fields. Located in 5,610 feet of water, it is one of the world's deepest dry tree spars. The platform, which is operated by another party, is capable of handling 210 MMcf/d of natural gas and 60 Mbbls/d of oil.

NGL marketing services

In addition to Williams Partners' gathering and processing operations, we market NGL products to a wide range of users in the energy and petrochemical industries. The NGL marketing business transports and markets equity NGLs from the production at its processing plants, and also markets NGLs on behalf of third-party NGL producers, including some of its fee-based processing customers, and the NGL volumes owned by Discovery Producer Services LLC (Discovery). The NGL marketing business bears the risk of price changes in these NGL volumes while they are being transported to final sales delivery points. In order to meet sales contract obligations, Williams Partners may purchase products in the spot market for resale. The majority of sales are based on supply contracts of one year or less in duration.

Other Partially Owned Operations

Fractionation and Storage

Williams Partners owns interests in and/or operates NGL fractionation and storage assets. These assets include a 50 percent interest in an NGL fractionation facility near Conway, Kansas with capacity of slightly more than 100 Mbbls/d and a 31.45 percent interest in another fractionation facility in Baton Rouge, Louisiana with a capacity of 60 Mbbls/d. Williams Partners also fully owns approximately 20 million barrels of NGL storage capacity in central Kansas near Conway.

Overland Pass Pipeline

In September 2010, Williams Partners completed the $424 million acquisition of an additional 49 percent ownership interest in Overland Pass Pipeline (OPPL), which increased our ownership interest to 50 percent. As long as we retain a 50 percent ownership interest in OPPL, we have the right to become operator. We have notified our partner of our intent to operate and are currently working on an early 2011 transition. OPPL includes a 760-mile NGL pipeline from Opal, Wyoming, to the Mid-Continent NGL market center in Conway, Kansas, along with 150- and 125-mile extensions into the Piceance and Denver-Joules basins in Colorado, respectively. Williams Partners' equity NGL volumes from our two Wyoming plants and our Willow Creek facility in Colorado are dedicated for transport on OPPL under a long-term shipping agreement.

Discovery

Williams Partners owns a 60 percent equity interest in and operates the facilities of Discovery. Discovery's assets include a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a 32 Mbbls/d NGL fractionator plant near Paradis, Louisiana and an offshore natural gas gathering and transportation system in the Gulf of Mexico.

Laurel Mountain

Williams Partners owns a 51 percent interest in a joint venture, Laurel Mountain Midstream LLC (Laurel Mountain), in the Marcellus Shale located in western Pennsylvania. Laurel Mountain's assets, which we operate, include a gathering system of approximately 1,000 miles of pipeline with a fourth quarter 2010 average throughput of approximately 125 MMcf/d. Laurel Mountain has a long-term, dedicated, volumetric-based fee agreement, with some exposure to natural gas prices, to gather the production of its joint venture partner's production in the northeast Pennsylvania area of the Marcellus Shale. Construction began in 2010 on numerous new pipeline segments and compressor stations, the largest of which is the Shamrock compressor station. The Shamrock compressor station will have an initial capacity of 60 MMcf/d, expandable to 350 MMcf/d, which will likely be the largest central delivery point out of the Laurel Mountain system.

Aux Sable

Williams Partners also owns a 14.6 percent equity interest in Aux Sable Liquid Products and its Channahon, Illinois gas processing and NGL fractionation facility near Chicago. The facility is capable of processing up to 2.1 Bcf/d of natural gas from the Alliance Pipeline system and fractionating approximately 92 Mbbls/d of extracted liquids into NGL products.

Operating statistics

The following table summarizes our significant operating statistics for Midstream:

	2010	2009	2008
Volumes:(1)			
Gathering (Tbtu)(3)	1,262	1,370	1,361
Plant inlet natural gas (Tbtu)	1,424	1,342	1,311
NGL production (Mbbls/d)(2)	174	164	154
NGL equity sales (Mbbls/d)(2)	80	80	80
Crude oil gathering (Mbbls/d)(2)	94	109	70

(1) Excludes volumes associated with partially owned assets such as our Discovery and Laurel Mountain investments that are not consolidated for financial reporting purposes.

(2) Annual average Mbbls/d.

(3) Amounts have been recast to reflect the November 2010 acquisition of certain gathering and processing assets in Colorado's Piceance basin from Exploration & Production.

Exploration & Production

Our Exploration & Production segment includes natural gas and oil development, production and gas marketing activities primarily located in the Rocky Mountain (primarily Colorado, North Dakota, New Mexico, and Wyoming), Northeast (Pennsylvania), and Mid-Continent (Oklahoma and Texas) regions of the United States. We specialize in production from tight-sands and shale formations and coal bed methane (CBM) reserves in the Piceance, Appalachian, Williston, San Juan, Powder River, Fort Worth, Green River and Arkoma basins. Almost 97 percent of our domestic proved reserves are natural gas. We also have international oil and gas interests, which include a 69 percent equity interest in Apco Oil and Gas International Inc., an oil and gas exploration and production company with operations in South America. If combined with our domestic proved reserves, our international interests would make up approximately 5 percent of our total proved reserves. Considering this, the reserves information included in this section relates only to our domestic activity. The gas marketing activities include transporting, scheduling, selling and hedging equity natural gas production as well as managing various natural gas related contracts such as transportation, storage and related hedges not utilized for our equity production. Additionally, Exploration & Production's marketing group procures all fuel and shrink requirements and manages transportation and hedging activities in support of our midstream business.

Our strategy is to continue to drill our existing proved undeveloped reserves, which comprise approximately 42 percent of proved reserves, and to drill in areas of probable and possible reserves in order to add to our proved reserves. Our current proved, probable, and possible reserves inventory provides us with strong capital investment opportunities for many years into the future.

Oil and Gas Reserves

The following table outlines our estimated net proved reserves expressed on a gas equivalent basis for the reporting periods December 31, 2010, 2009 and 2008. Proved reserves for 2010 and 2009 were prepared under rules issued by the SEC on January 14, 2009. We prepare our own reserves estimates and the majority of our December 31, 2010 reserves were audited by Netherland, Sewell & Associates (NSAI) or Miller and Lents, Ltd (M&L). Proved reserves information is reported as gas equivalents, since oil volumes are insignificant in the three years shown below. Reserves for 2010 are approximately 97 percent natural gas. Reserves are more than 99 percent natural gas for 2009 and 2008. Oil reserves increased to approximately 3 percent of total proved reserves in 2010 as a result of a fourth quarter acquisition of undeveloped acreage and producing properties located in the Williston basin.

Summary of oil and gas reserves:

	December 31,		
	2010	2009	2008
		(Bcfe)(1)	
Proved developed reserves	2,498	2,387	2,456
Proved undeveloped reserves	1,774	1,868	1,883
Total proved reserves	4,272	4,255	4,339

(1) Gas equivalents are calculated using a ratio of 6 mcf of gas to 1 barrel of oil.

Basin	Proved Reserves December 31, 2010
	(Bcfe)
Piceance	2,927
Powder River	348
San Juan	554
Fort Worth	196
Appalachian	28
Williston	136
Other	83
Total	4,272

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 with the Department of Energy (DOE) and the SEC. The estimates furnished to the DOE have been consistent with those furnished to the SEC.

The 2010 year-end proved reserves were derived using the 12-month average, first-of-the-month Henry Hub spot price of $4.38 per MMbtu, adjusted for locational price differentials. During 2010, we added 508 Bcfe of net additions to our proved reserves through drilling 1,162 gross wells at a capital cost of approximately $988 million.

Reserves estimation process

Our reserves are estimated by deterministic methods by an appropriate combination of production performance analysis and volumetric techniques. The proved reserves for economic undrilled locations are estimated by analogy or volumetrically from offset developed locations. Reservoir continuity and lateral persistence of our tight-sands, shale and CBM reservoirs is established by combinations of subsurface analysis, 2D and 3D seismic, and pressure data. Understanding reservoir quality may be augmented by core samples analysis.

The engineering staff of each basin asset team provides the reserves modeling and forecasts for their respective areas. Various departments also participate in the preparation of the year-end reserves estimate by providing supporting information such as pricing, capital costs, expenses, ownership, gas gathering and gas quality. The departments and their roles in the year-end reserves process are coordinated by our reserves analysis department. The reserves analysis department's responsibilities also include performing an internal review of reserves data for reasonableness and accuracy, working with the third-party consultants and the asset teams to successfully complete the third-party reserves audit, finalizing the year-end reserves report, and reporting reserves data to accounting.

The preparation of our year-end reserves report is a formal process. Early in the year, we begin with a review of the existing internal processes and controls to identify where improvements can be made from the prior year's reporting cycle. Later in the year, the reserves staffs from the asset teams submit their preliminary reserves data to the reserves analysis department. After review by the reserves analysis department, the data is submitted to our third party engineering consultants, NSAI and M&L, to begin their audits. After this point, reserves data, analysis and further review are conducted and iterated between the asset teams, reserves analysis department and our third party engineering consultants. In early December, reserves are reviewed with senior management. The process concludes when all parties agree upon the reserve estimates and audit tolerance is achieved.

The reserves estimates resulting from our process are subjected to both internal and external controls to promote transparency and accuracy of the year-end reserves estimates. Our internal reserves analysis team is independent and does not work within an asset team or report directly to anyone on an asset team. The reserves analysis department provides detailed independent review and extensive documentation of the year-end process. Our internal processes and controls, as they relate to the year-end reserves, are reviewed and updated. The compensation of our reserves analysis team is not linked to reserves additions or revisions.

Approximately 93 percent of our total year-end 2010 domestic proved reserves estimates were audited by 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 and have been prepared in accordance with principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. NSAI is satisfied with our methods and procedures in preparing the December 31, 2010 reserves estimates and future revenue, and noted nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, as prepared by us. The report of NSAI is included in Exhibit 99.1 to this Form 10-K.

In addition, reserves estimates related to properties associated with the former Williams Coal Seam Gas Royalty Trust were audited by M&L. These properties represent approximately 1 percent of our total domestic proved reserves estimates. The report of M&L is included in Exhibit 99.2 to this Form 10-K.

The technical person primarily responsible for overseeing preparation of the reserves estimates and the third-party reserves audit is the Director of Reserves and Production Services. The Director's qualifications include 28 years of reserves evaluation experience, a B.S. in geology from the University of Texas at Austin, an M.S. in Physical Sciences from the University of Houston, and membership in the American Association of Petroleum Geologists and The Society of Petroleum Engineers.

Proved undeveloped reserves (PUDs)

The majority of our reserves is concentrated in unconventional tight-sands, shale and coal bed gas reservoirs. We use available geoscience and engineering data to establish drainage areas and reservoir continuity beyond one direct offset from a producing well, which provides additional proved undeveloped reserves. Inherent in the methodology is a requirement for significant well density of economically producing wells to establish reasonable certainty. In fields where producing wells are less concentrated, only direct offsets from proved producing wells were assigned the proved undeveloped reserves classification. No new technologies were used to assign proved undeveloped reserves.

At December 31, 2010, our proved undeveloped reserves were 1,774 Bcfe — a decrease of 94 Bcfe over our December 31, 2009 proved undeveloped reserves estimate of 1,868 Bcfe. During 2010, 280 Bcfe of our December 31, 2009 proved undeveloped reserves were converted to proved developed reserves. An additional 129 Bcfe was added due to the development of unproved locations. We have reclassified a net 253 Bcfe from proved to probable reserves attributable to locations not expected to be developed within five years. This amount is predominantly in the Piceance basin where the company has a large inventory of drilling locations. The downward revision has been offset by the addition of 342 Bcfe of new proved undeveloped drilling locations.

All proved undeveloped locations are scheduled to be spud within the next five years. Our five-year forecast indicates increasing capital to allow for the addition of rigs in years 2013-2015 in the Piceance basin. Our undeveloped estimate contains 91 Bcfe of aging PUDs. The majority of these are scheduled to be spud by year-end 2011.

Oil and Gas Properties and Production, Production Prices, and Production Costs

The following table summarizes our domestic sales volumes for the years indicated:

	2010	2009	2008
		(Bcfe)	
Piceance	245.9	254.6	237.7
Powder River	83.8	88.9	83.6
San Juan	51.5	53.1	52.8
Fort Worth	21.5	25.2	16.6
Appalachian	1.8	0.1	—
Williston	0.1	—	—
Other	8.5	9.6	9.7
Total net production sold	413.1	431.5	400.4

The following table summarizes our domestic price and cost information for the years indicated and has been recast for the sale of certain of our gathering and processing assets in the Piceance basin to Williams Partners in November 2010:

	2010	2009	2008
		($/Mcfe)	
Average production costs excluding production taxes(1)	$0.59	$0.50	$0.56
Average sales price(2)	$4.42	$3.42	$6.95
Realized gain from hedging	$0.81	$1.43	$0.09
Realized Average Price	$5.23	$4.85	$7.04

(1) Includes lease and other operating expense and facility operating expense.

(2) Not reduced for gathering, processing, and transportation paid to affiliates and third parties of $1.02 in 2010, $0.79 in 2009, and $0.71 in 2008.

Drilling and Exploratory Activities

We focus on lower-risk development drilling. Our development drilling success rate was approximately 99 percent in each of 2010, 2009, and 2008.

The following table summarizes domestic drilling activity by number and type of well for the periods indicated:*

	2010		2009		2008	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Piceance	398	360	349	303	687	624
Powder River	531	242	233	95	702	324
San Juan	43	15	77	39	95	37
Fort Worth	39	36	43	41	58	51
Appalachian	8	3	8	4	n/a	n/a
Williston	—	—	n/a	n/a	n/a	n/a
Other	138	2	165	4	240	14
Productive exploration	—	—	3	1	4	2
Nonproductive, including exploration	5	3	4	1	1	—
Total	1,162	661	882	488	1,787	1,052

* 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. All of the wells drilled were natural gas wells.

In 2010, there were 5 gross nonproductive development wells and 3 net nonproductive development wells. Total gross operated wells drilled were 656 in 2010, 472 in 2009, and 1,125 in 2008.

Present Activities

At December 31, 2010, we had 27 gross (16 net) wells in the process of being drilled.

Delivery Commitments

We hold a long-term obligation to deliver on a firm basis 200,000 MMBtu/d of gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance basin. The Piceance, being our largest producing basin, holds ample reserves to fulfill this obligation without risk of nonperformance during periods of normal infrastructure and market operations. While the daily volume of gas is large and represents a significant percentage of our daily production, this transaction does not represent a material exposure.

Purchase Commitments

In connection with a gathering agreement entered into by Williams Partners with a third party in December 2010, we concurrently agreed to buy up to 200,000 MMBtu/d of natural gas priced at market prices from the same third party. Purchases under the 12-year contract are expected to begin in the third quarter of 2011. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

Oil and Gas Properties, Wells, Operations, and Acreage

The table below summarizes 2010 productive wells by area:*

	Gas Wells (Gross)	Gas Wells (Net)	Oil Wells (Gross)	Oil Wells (Net)
Piceance	3,923	3,587	—	—
Powder River	6,404	2,884	—	—
San Juan	3,267	881	—	—
Fort Worth	286	233	—	—
Appalachian	14	6	—	—
Williston	—	—	19	13
Other	1,340	299	—	—
Total	15,234	7,890	19	13

* We use the term "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.

At December 31, 2010, there were 181 gross and 105 net producing wells with multiple completions.

The following table summarizes our leased acreage as of December 31, 2010:

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Piceance	133,428	102,835	157,017	108,165	290,445	211,000
Powder River	551,113	250,179	399,869	175,371	950,982	425,550
San Juan	237,587	119,422	2,100	1,576	239,687	120,998
Fort Worth	28,876	21,173	12,306	8,309	41,182	29,482
Appalachian	1,828	914	108,023	98,387	109,851	99,301
Williston	16,178	13,483	229,640	190,148	245,818	203,631
Other	120,538	60,559	199,077	118,734	319,615	179,293
Total	1,089,548	568,565	1,108,032	700,690	2,197,580	1,269,255

Piceance basin

The Piceance basin is located in northwestern Colorado and is our largest area of concentrated development. During 2010, we operated an average of 11 drilling rigs in the basin. This area has 1,567 undrilled proved locations in inventory. During 2010, an average of approximately 6.3 million gallons of NGLs were recovered each month at plants now owned and operated within Williams Partners, which were marketed separately from the residue natural gas.

Powder River basin

The Powder River basin is located in northeast Wyoming. The Powder River basin includes large areas with multiple coal seam potential, targeting thick coal bed methane formations at shallow depths.

San Juan basin

The San Juan basin is located in northwest New Mexico and southwest Colorado. We provide a significant amount of equity production that is gathered and/or processed by Williams Partners' facilities in the San Juan basin.

Fort Worth basin

The Fort Worth basin is located in north central Texas where we drill horizontally into the Barnett Shale.

Appalachian basin

The Appalachian basin acreage is primarily located in northeastern Pennsylvania where we apply horizontal drilling in the Marcellus Shale. We have continued to expand our position since our entry into the basin in 2009.

Williston basin

The Williston basin acreage is located in North Dakota and Montana. Our focus in the basin is in North Dakota's Bakken/Three Forks oil play where we have a 89,420 net acreage position, of which approximately 85,800 were acquired in December 2010 and are on the Fort Berthold Indian Reservation.

Other properties

Other properties are primarily comprised of interests in the Arkoma basin in southeastern Oklahoma. Also included are exploration activity and other miscellaneous activity.

Hedging Activity

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative contracts for a portion of our expected future production. See further discussion in *Management's Discussion and Analysis of Financial Condition and Results of Operations — Exploration & Production*, included in Item 7 of this Form 10-K

Acquisitions & Divestitures

During the second quarter of 2010, we entered into an agreement to acquire additional Appalachian leasehold acreage positions and a 5 percent overriding royalty interest associated with these acreage positions. These acquisitions nearly double our acreage holdings in the Marcellus Shale and closed in July for $599 million, including closing adjustments.

During 2010, we also spent a total of $164 million to acquire additional unproved leasehold acreage positions in the Marcellus Shale.

In October 2010, we exercised our right under the Williams Coal Seam Gas Royalty Trust Agreement to acquire the royalty interests for $22 million, including closing adjustments upon termination of the the Trust. Prior to the purchase, the Trust owned net profits interests in certain proved coal seam gas properties owned by Williams Production Company, LLC (WPC) and located in the San Juan basin.

In November 2010, we sold certain of our gathering and processing assets in Colorado's Piceance basin to Williams Partners for $702 million in cash and approximately 1.8 million common units. The assets include the Parachute Plant Complex, three other treating facilities with a combined processing capacity of 1.2 Bcf/d, and a gathering system with approximately 150 miles of pipeline. There are more than 3,300 wells connected to the gathering system, which includes pipelines ranging up to 30-inch trunk lines. The transaction also includes a life-of-lease dedication from Exploration & Production.

In December 2010, we acquired a company that holds a major acreage position (approximately 85,800 net acres and includes 19 producing wells) in North Dakota's Bakken Shale oil play (Williston basin) that will diversify our interests into light, sweet crude oil production. The purchase price was approximately $949 million, including closing adjustments.

Other

Domestic olefins

In the Gulf of Mexico region, we own a 5/6 interest in and are the operator of an NGL light-feed olefins cracker in Geismar, Louisiana, with a total production capacity of 1.35 billion pounds of ethylene and 90 million pounds of propylene per year. Our feedstocks for the cracker are ethane and propane; as a result, we are primarily exposed to the price spread between ethane and propane, and ethylene and propylene, respectively. Ethane and propane are available for purchase from third parties and from affiliates. We own ethane and propane pipeline systems in Louisiana that provide feedstock transportation to the Geismar plant and other third-party crackers. Additionally, we own a refinery grade propylene splitter and associated pipeline with a production capacity of approximately 500 million pounds per year of propylene. At our propylene splitter, we purchase refinery grade propylene and fractionate it into polymer grade propylene and propane; as a result we are exposed to the price spread between those commodities. As a merchant producer of ethylene and propylene, our product sales are to customers for use in making plastics and other downstream petrochemical products destined for both domestic and export markets. Our olefins business also operates an ethylene storage hub at Mont Belvieu using leased third-party underground storage wells.

We also market olefin and NGL products to a wide range of users in the energy and petrochemical industries. In order to meet sales contract obligations, we may purchase products for resale.

Canadian midstream

Our Canadian operations include an oil sands off-gas processing plant located near Ft. McMurray, Alberta, and an olefin fractionation facility and a butylene/butane splitter facility, both of which are located at Redwater, Alberta, which is near Edmonton, Alberta. We operate the Ft. McMurray area processing plant, while another party operates the Redwater facilities on our behalf. The butylene/butane splitter was completed and placed into service in August 2010. Our Ft. McMurray area facilities extract liquids from the off-gas produced by a third-party oil sands bitumen upgrading process. Our arrangement with the third-party upgrader is a "keep-whole" type where we remove a mix of NGLs and olefins from the off-gas and return the equivalent heating value back in the form of natural gas. We fractionate, treat, store, terminal and sell the propane, propylene, butane, butylene and condensate recovered from this process. Our commodity price exposure is the spread between the price for natural gas and the NGL and olefin products we produce. We continue to be the only NGL/olefins fractionator in western Canada and the only treater/processor of oil sands upgrader off-gas. Our extraction of liquids from upgrader off-gas streams allows the upgraders to burn cleaner natural gas streams and reduces their overall air emissions.

The Ft. McMurray extraction plant has processing capacity of 111 MMcf/d with the ability to recover in excess of 17 Mbbls/d of olefin and NGL products. Our Redwater fractionator has a liquids handling capacity of 18 Mbbls/d. The new butylene/butane splitter, which has a production capacity of 3.7 Mbbls/d of butylene and 3.7 Mbbls/d of normal butane, further fractionates the butylene/butane mix product produced at our Redwater fractionators into separate butylene and butane products, which receive higher values and are in greater demand. Our products are sold within Canada and the United States.

Canadian expansion project

Construction began in 2010 on a 261-mile, 12-inch diameter Canadian pipeline which will transport recovered NGLs and olefins from our processing plant in Ft. McMurray to our Redwater fractionation facility. The pipeline will have sufficient capacity to transport additional NGLs and olefins from our existing operations as well as from other NGLs and olefins produced from oil sands off-gas. The project will be constructed using cash previously generated from Canadian and other international projects. We anticipate an in-service date in 2012.

Other

Considering the deteriorating circumstances in Venezuela, in 2009 we fully impaired our $75 million investment in Accroven SRL, a Venezuelan operation, which included two 400 MMcf/d NGL extraction plants, a 50 Mbbls/d NGL fractionation plant and associated storage and refrigeration facilities. (See Note 2 of Notes to Consolidated Financial Statements.) In June of 2010, we sold our 50 percent interest in Accroven to the state-owned oil company, Petróleos de Venezuela S.A. (PDVSA) for $107 million. Of this amount, $13 million was received in cash at closing and another $30 million was received in August 2010. The remainder is due in six quarterly payments beginning October 31, 2010. The first quarterly payment of $11 million was received in January 2011 and will be recognized as income in 2011. We will continue to recognize the resulting gain as cash is received. Accroven was not part of our operations that were expropriated by the Venezuelan government in May 2009.

Operating statistics

The following table summarizes our significant operating statistics for Other:

	2010	2009	2008
Volumes:			
Canadian NGL equity sales (Mbbls/d)	8	8	7
Olefin (ethylene and propylene) sales (millions of pounds)	1,529	1,728	1,605

Additional Business Segment Information

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

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

We perform certain management, legal, financial, tax, consultation, information technology, administrative and other services for our subsidiaries.

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

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

REGULATORY MATTERS

Williams Partners

Gas Pipeline Business. Williams Partners gas pipeline's interstate transmission and storage activities are subject to FERC regulation under the Natural Gas Act of 1938 (NGA) and under the Natural Gas Policy Act of 1978, and, as such, its rates and charges for the transportation of natural gas in interstate commerce, its accounting, and the extension, enlargement or abandonment of its jurisdictional facilities, among other things, are subject to regulation. Each gas pipeline company holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities and properties for which certificates are required under the NGA. Each gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, and the Pipeline Safety Improvement Act of 2002, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. FERC Standards of Conduct govern how our interstate pipelines communicate and do business with gas marketing employees. Among other things, the Standards of Conduct require that interstate pipelines not operate their systems to preferentially benefit gas marketing functions.

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;
- Contract and volume throughput assumptions.

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

Pipeline Integrity Regulations

For Williams Partners' gas pipeline business, Transco and Northwest Pipeline have developed an Integrity Management Plan that we believe meets the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) final rule that was issued pursuant to the requirements of the Pipeline Safety Improvement Act of 2002. The rule requires gas pipeline operators to develop an integrity management program for transmission pipelines that could affect high consequence areas in the event of pipeline failure. The Integrity Management Program includes a baseline assessment plan along with periodic reassessments to be completed within required timeframes. In meeting the integrity regulations, Transco and Northwest Pipeline have identified high consequence areas and developed baseline assessment plans. Transco and Northwest Pipeline are on schedule to complete the required assessments within required timeframes. Currently, Transco and Northwest Pipeline estimate the cost to complete the required initial assessments over the period from 2011 and 2012 and associated remediation will be primarily capital in nature and range between $80 million and $110 million for Transco and between $50 million and $60 million for Northwest Pipeline. Ongoing periodic reassessments and initial assessments of any new high consequence areas will be completed within the timeframes required by the rule. Management considers the costs associated with compliance with the rule to be prudent costs incurred in the ordinary course of business, and, therefore, recoverable through Transco's and Northwest Pipeline's rates.

Midstream Business. For Williams Partners' midstream business, 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 the midstream business gathers gas, currently only Texas actively regulates gathering activities. Texas regulates gathering primarily through complaint mechanisms under which the state commission may resolve disputes involving an individual gathering arrangement. Although offshore gathering facilities are not subject to the NGA, offshore transmission pipelines are subject to the NGA, and in recent years the FERC has taken a broad view of offshore transmission, finding many shallow-water pipelines to be jurisdictional transmission. Most offshore gathering facilities are subject to the OCSLA, which provides in part that outer continental shelf pipelines "must provide open and nondiscriminatory access to both owner and nonowner shippers."

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

The midstream business owns an interest in, and is expected to become the operator in 2011, of Overland Pass Pipeline, which is an interstate natural gas liquids pipeline regulated by the FERC pursuant to the Interstate Commerce Act. Overland Pass provides transportation service pursuant to tariffs filed with the FERC.

Exploration & Production

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

Our gas marketing business is subject to a variety of laws and regulations at the local, state and federal levels, including the FERC and the Commodity Futures Trading Commission regulations. In addition, natural gas markets continue to be subject to numerous and wide-ranging federal and state regulatory proceedings and investigations.

Other

Our Canadian assets are regulated by the Energy Resources Conservation Board (ERCB) 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 noncompliance with the applicable regulations is at issue, the ERCB and Alberta Environment have implemented an enforcement process with escalating consequences.

See Note 16 of our Notes to Consolidated Financial Statements for further details on our regulatory matters.

ENVIRONMENTAL MATTERS

Our 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 pollutants into the air, soil, or water, as well as liability for cleanup 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, processing or treating facilities, transportation facilities and storage tanks;
- Damage to oil and gas wells resulting from accidents during normal operations;
- Blowouts, cratering and explosions.

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

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

For a discussion of specific environmental issues, see "Environmental" under Management's Discussion and Analysis of Financial Condition and Results of Operations and "Environmental Matters" in Note 16 of our Notes to Consolidated Financial Statements.

COMPETITION

Williams Partners

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

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

States are in the process of developing new energy plans that may require utilities to encourage energy saving measures and diversify their energy supplies to include renewable sources. This could lower the growth of gas demand.

These factors have increased the risk that customers will reduce their contractual commitments for pipeline capacity. Future utilization of pipeline capacity will also depend on competition from LNG imported into markets and new pipelines from the Rockies and other new producing areas.

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

Exploration & Production

Our exploration and production business 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.

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

Other

Ethylene and propylene markets, and therefore our olefins business, compete in a worldwide marketplace. Due to our NGL feedstock position at Geismar, we will benefit from the lower cost position in North America versus other crude-based feedstocks worldwide. The majority of North American olefins producers have significant downstream petrochemical manufacturing for plastics and other products. As such, they buy or sell ethylene and propylene as required. We operate as a merchant seller of olefins with no downstream manufacturing, and therefore can be either a supplier or a competitor at any given time to these other companies depending on their market balances. Generally, we are viewed primarily as a supplier to these companies and not as a direct competitor. We compete on the basis of service, price and availability of the products we produce.

Our Canadian midstream facilities continue to be the only NGL/olefins fractionator in western Canada and the only treater/processor of oil sands upgrader off-gas. Our extraction of liquids from the upgrader off-gas stream allows the upgraders to burn cleaner natural gas streams and reduce their overall air emissions. Our Canadian midstream business competes for the sale of its products with traditional Canadian midstream companies on the basis of operational expertise, price, service offerings and availability of the products we produce.

EMPLOYEES

At February 1, 2011, we had approximately 5,022 full-time employees. 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 three fiscal years, located in the United States and all foreign countries.

Item 1A. ***Risk Factors***

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

Certain matters contained in this report include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements relate to anticipated financial performance, management's plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "goals," "objectives," "targets," "planned," "potential," "projects," "scheduled," "will" or other similar expressions. These forward-looking statements are based on management's beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Financial condition and liquidity;
- Business strategy;
- Estimates of proved gas and oil reserves;
- Reserve potential;
- Development drilling potential;
- Cash flow from operations or results of operations;
- Seasonality of certain business segments;
- Natural gas, natural gas liquids and crude oil 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 report. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring and developing future natural gas and oil reserves), market demand, volatility of prices, and the availability and cost of capital;
- Inflation, interest rates, fluctuation in foreign exchange, and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- The strength and financial resources of our competitors;
- Development of alternative energy sources;
- The impact of operational and development hazards;
- Costs of, changes in, or the results of laws, government regulations (including climate change legislation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation, and rate proceedings;
- Our costs and funding obligations for defined benefit pension plans and other postretirement benefit plans;
- Changes in maintenance and construction costs;
- Changes in the current geopolitical situation;
- Our exposure to the credit risk of our customers;
- Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;
- Risks associated with future weather conditions;
- Acts of terrorism;
- Additional risks described in our filings with the Securities and Exchange Commission.

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. These factors are described in the following section.

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 Related to Separation Plan

If our plan to separate our exploration and production business is delayed or not completed, our stock price may decline and our growth potential may not be enhanced.

On February 16, 2011, we announced that our Board of Directors approved pursuing a plan to divide our businesses into two separate, publicly traded corporations. The plan calls for a separation of our exploration and production business through an initial public offering of up to 20 percent of the corporation holding that business in 2011 and a tax-free spinoff of our remaining interest in that corporation to our shareholders in 2012. The completion and timing of each of the transactions is dependent on a number of factors including, but not limited to, the macroeconomic environment, credit markets, equity markets, energy prices, the receipt of a tax opinion from counsel and/or Internal Revenue Service rulings, final approvals from our Board of Directors and other customary matters. We may not complete the transactions at all or complete the transactions on the timeline or on the terms that we announced. If the transactions are not completed or delayed, our stock price may decline and our growth potential may not be enhanced.

Risks Inherent in our Business

The long-term financial condition of our gas pipeline 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 the prices of and market demand for natural gas.

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

Production from existing wells and natural gas supply basins with access to our pipeline systems will also naturally decline over time. The amount of natural gas reserves underlying these wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Additionally, the competition for natural gas supplies to serve other markets could reduce the amount of natural gas supply for our customers. Accordingly, to maintain or increase the contracted capacity or the volume of natural gas transported on or gathered through our pipeline systems and cash flows associated with the gathering and transportation of natural gas, our customers must compete with others to obtain adequate supplies of natural gas. In addition, if natural gas prices in the supply basins connected to our pipeline systems are higher than prices in other natural gas producing regions, our ability to compete with other transporters may be negatively impacted on a short-term basis, as well as with respect to our long-term recontracting activities. If new supplies of natural gas are not obtained to replace the natural decline in volumes from existing supply areas, if natural gas supplies are diverted to serve other markets, if development in new supply basins where we do not have significant gathering or pipeline systems reduces demand for our services, or if environmental regulators restrict new natural gas drilling, the overall volume of natural gas transported, gathered and stored on our system would decline, which could have a material adverse effect on our business, financial condition and results of operations. In addition, new LNG import facilities built near our markets could result in less demand for our gathering and transportation facilities.

Significant prolonged changes in natural gas prices could affect supply and demand and cause a termination of our transportation and storage contracts or a reduction in throughput on the gas pipeline systems.

Higher natural gas prices over the long term could result in a decline in the demand for natural gas and, therefore, in long-term transportation and storage contracts or throughput on our gas pipeline systems. Also, lower natural gas prices over the long term could result in a decline in the production of natural gas resulting in reduced contracts or throughput on the gas pipeline systems. As a result, significant prolonged changes in natural gas prices could have a material adverse effect on our gas pipeline business, financial condition, results of operations and cash flows.

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

Our revenues, operating results, future rate of growth and the value of certain segments of our businesses depend primarily upon the prices of NGLs, natural gas, oil, or other commodities, and the differences between prices of these commodities. Price volatility can impact both the amount we receive for our products and services and the volume of products and services we sell. Prices affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Any of the foregoing can also have an adverse effect on our business, results of operations, financial condition and cash flows.

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

- Worldwide and domestic supplies of and demand for natural gas, NGLs, oil, and related commodities;
- Turmoil in the Middle East and other producing regions;
- The activities of the Organization of Petroleum Exporting Countries;
- Terrorist attacks on production or transportation assets;
- Weather conditions;
- The level of consumer demand;
- The price and availability of other types of fuels;
- The availability of pipeline capacity;
- Supply disruptions, including plant outages and transportation disruptions;
- The price and level of foreign imports;
- Domestic and foreign governmental regulations and taxes;
- Volatility in the natural gas and oil markets;
- The overall economic environment;
- The credit of participants in the markets where products are bought and sold;
- The adoption of regulations or legislation relating to climate change.

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

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

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations and debt and equity issuances. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of natural gas and oil, and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to access additional bank debt, issue debt or equity securities or access other methods of financing on an economic basis to meet our capital expenditure budget. As a result, our capital expenditure plans may have to be adjusted.

Failure to replace reserves may negatively affect our business.

The growth of our Exploration & Production business depends upon our ability to find, develop or acquire additional natural gas and oil reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. We may not be able to find, develop or acquire additional reserves on an economic basis. If natural gas or oil prices increase, our costs for additional reserves would also increase; conversely if natural gas or oil prices decrease, it could make it more difficult to fund the replacement of our reserves.

Exploration and development drilling may not result in commercially productive reserves.

Our past success rate for drilling projects should not be considered a predictor of future commercial success. We do not always encounter commercially productive reservoirs through our drilling operations. The new wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- Increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment, skilled labor, capital or transportation;
- Unexpected drilling conditions or problems;
- Regulations and regulatory approvals;
- Changes or anticipated changes in energy prices;
- Compliance with environmental and other governmental requirements.

Estimating reserves and future net revenues involves uncertainties. Negative revisions to reserve estimates, oil and gas prices or assumptions as to future natural gas prices may lead to decreased earnings, losses, or 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 that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions, but should not be considered as a guarantee of results for future drilling projects.

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

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

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also be sufficient to trigger impairment losses on certain properties which would result in a noncash charge to earnings.

Certain of our gas pipeline services are subject to long-term, fixed-price contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts.

Our gas pipelines provide some services pursuant to long-term, fixed price contracts. It is possible that costs to perform services under such contracts will exceed the revenues they collect for their services. Although most of the services are priced at cost-based rates that are subject to adjustment in rate cases, under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a "negotiated rate" that may be above or below the FERC regulated cost-based rate for that service. These "negotiated rate" contracts are not generally subject to adjustment for increased costs that could be produced by inflation or other factors relating to the specific facilities being used to perform the services.

We may not be able to maintain or replace expiring natural gas transportation and storage contracts at favorable rates or on a long-term basis.

Our primary exposure to market risk for our gas pipelines occurs at the time the terms of their existing transportation and storage contracts expire and are subject to termination. Upon expiration of the terms we may not be able to extend contracts with existing customers to obtain replacement contracts at favorable rates or on a long-term basis.

The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- The level of existing and new competition to deliver natural gas to our markets;
- The growth in demand for natural gas in our markets;
- Whether the market will continue to support long-term firm contracts;
- Whether our business strategy continues to be successful;
- The level of competition for natural gas supplies in the production basins serving us;

- The effects of state regulation on customer contracting practices.

Any failure to extend or replace a significant portion of our existing contracts may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

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

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

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

The impact of changes in market prices for NGLs and natural gas on the average prices paid or received by us may be reduced based on the level of our hedging activities. These hedging arrangements may limit or enhance our margins if the market prices for NGLs or natural gas were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss in certain circumstances, including instances in which:

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

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

In July 2010, federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted. The Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Among other things, the Act provides for the creation of position limits for certain derivatives transactions, as well as requiring certain transactions to be cleared on exchanges for which cash collateral will be required. The final impact of the Act on our hedging activities is uncertain at this time due to the requirement that the SEC and the Commodities Futures Trading Commission (CFTC) promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. These new rules and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts or reduce the availability of derivatives. Although we believe the derivative contracts that we enter into should not be impacted by position limits and should be exempt from the requirement to clear transactions through a central exchange or to post collateral, the impact upon our businesses will depend on the outcome of the implementing regulations adopted by the CFTC.

Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures. A requirement to post cash collateral could therefore reduce our ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of derivatives as a result of the Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

We depend on certain key customers for a significant portion of our revenues. The loss of any of these key customers or the loss of any contracted volumes could result in a decline in our business.

Our gas pipeline and midstream businesses rely on a limited number of customers for a significant portion of their revenues. Although some of these customers are subject to long-term contracts, extensions or replacements of these contracts may not be renegotiated on favorable terms, if at all. The loss of all, or even a portion of the revenues from natural gas, NGLs or contracted volumes, as applicable, supplied by these customers, as a result of competition, creditworthiness, inability to negotiate extensions or replacements of contracts or otherwise, could have a material adverse effect on our business, financial condition, results of operations, and cash flows, unless we are able to acquire comparable volumes from other sources.

We are exposed to the credit risk of our customers, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers in the ordinary course of our business. Generally, our customers are rated investment grade, are otherwise considered creditworthy or are required to make prepayments or provide security to satisfy credit concerns. However, our credit procedures and policies may not be adequate to fully eliminate customer credit risk. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers' creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur, and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We have numerous competitors in all aspects of our businesses, and additional competitors may enter our markets. Other companies with which we compete may be able to respond more quickly to new laws or regulations or emerging technologies, or to devote greater resources to the construction, expansion or refurbishment of their facilities than we can. In addition, current or potential competitors may make strategic acquisitions or have greater financial resources than we do, which could affect our ability to make investments or acquisitions. Similarly, a highly-liquid competitive commodity market in natural gas and increasingly competitive markets for natural gas services, including competitive secondary markets in pipeline capacity, have developed. As a result, pipeline capacity is being used more efficiently, and peaking and storage services are increasingly effective substitutes for annual pipeline capacity. We may not be able to compete successfully against current and future competitors and any failure to do so could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our operations are subject to operational hazards and unforeseen interruptions for which they may not be adequately insured.

There are operational risks associated with drilling for, production, gathering, transporting, storage, processing and treating of natural gas and the fractionation and storage of NGLs, including:

- Hurricanes, tornadoes, floods, fires, extreme weather conditions, and other natural disasters;
- Aging infrastructure and mechanical problems;
- Damages to pipelines and pipeline blockages;
- Uncontrolled releases of natural gas (including sour gas), NGLs, brine or industrial chemicals;
- Collapse of storage caverns;
- Operator error;
- Damage inadvertently caused by third-party activity, such as operation of construction equipment;
- Pollution and environmental risks;
- Fires, explosions, craterings and blowouts;
- Risks related to truck and rail loading and unloading;
- Risks related to operating in a marine environment;
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. The location of certain segments of our facilities in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In spite of our precautions, an event such as those described above could cause considerable harm to people or property, and could have a material adverse effect on our financial condition 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.

Our costs of maintaining or repairing our facilities may exceed our expectations and the FERC or competition in our markets may not allow us to recover such costs in the rates we charge for our services.

We could experience unexpected leaks or ruptures on our gas pipeline and midstream systems, or be required by regulatory authorities to undertake modifications to our systems that could result in a material adverse impact on our business, financial condition and results of operations if the costs of maintaining or repairing our facilities exceed current expectations and the FERC or competition in our markets do not allow us to recover such costs in the rates we charge for our service.

We do not insure against all potential losses and could be seriously harmed by unexpected liabilities or by the inability of our insurers to satisfy our claims.

We are not fully insured against all risks inherent to our business, including environmental accidents. We do not maintain insurance in the type and amount to cover all possible risks of loss.

We currently maintain excess liability insurance with limits of $610 million per occurrence and in the annual aggregate with a $2 million per occurrence deductible. This insurance covers us, our subsidiaries, and certain of our affiliates for legal and contractual liabilities arising out of bodily injury or property damage, including resulting loss of use to third parties. This excess liability insurance includes coverage for sudden and accidental pollution liability for full limits, with the first $135 million of insurance also providing gradual pollution liability coverage for natural gas and NGL operations.

Although we maintain property insurance on property we own, lease or are responsible to insure, the policy may not cover the full replacement cost of all damaged assets or the entire amount of business interruption loss we may experience. In addition, certain perils may be excluded from coverage or sub-limited. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. We may elect to self insure a portion of our risks. We do not insure our onshore underground pipelines for physical damage, except at certain locations such as river crossings and compressor stations. Only certain offshore key-assets are covered for property damage and the resulting business interruption when loss is due to a named windstorm event and coverage for loss caused by a named windstorm is significantly sub-limited. All of our insurance is subject to deductibles. If a significant accident or event occurs for which we are not fully insured it could adversely affect our operations and financial condition.

In addition, any insurance company that provides coverage to us may experience negative developments that could impair their ability to pay any of our claims. As a result, we could be exposed to greater losses than anticipated and may have to obtain replacement insurance, if available, at a greater cost.

The occurrence of any risks not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows, and our ability to repay our debt.

Execution of our capital projects subjects us to construction risks, increases in labor costs and materials, and other risks that may adversely affect financial results.

The growth in our gas pipeline and midstream businesses may be dependent upon the construction of new natural gas gathering, transportation, processing or treating pipelines and facilities or natural gas liquids fractionation or storage facilities, as well as the expansion of existing facilities. Construction or expansion of these facilities is subject to various regulatory, development and operational risks, including:

- The ability to obtain necessary approvals and permits by regulatory agencies on a timely basis and on acceptable terms;
- The availability of skilled labor, equipment, and materials to complete expansion projects;
- Potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project;
- Impediments on our ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms;
- The ability to construct projects within estimated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control, that may be material;
- The ability to access capital markets to fund construction projects.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve expected investment return, which could adversely affect our results of operations, financial position or cash flows.

Our costs and funding obligations for our defined benefit pension plans and costs for our other postretirement benefit plans are affected by factors beyond our control.

We have defined benefit pension plans covering substantially all of our U.S. employees and other postretirement benefit plans covering certain eligible participants. The timing and amount of our funding requirements under the defined benefit pension plans depend upon a number of factors we control, including changes to pension plan benefits, as well as factors outside of our control, such as asset returns, interest rates and changes in pension laws. Changes to these and other factors that can significantly increase our funding requirements could have a significant adverse effect on our financial condition and results of operations.

One of our subsidiaries acts as the general partner of a publicly traded limited partnership, Williams Partners L.P. As such, this subsidiary's operations may involve a greater risk of liability than ordinary business operations.

One of our subsidiaries acts as the general partner of WPZ, a publicly-traded limited partnership. This subsidiary may be deemed to have undertaken fiduciary obligations with respect to WPZ as the general partner and to the limited partners of WPZ. Activities determined to involve fiduciary obligations to other persons or entities typically involve a higher standard of conduct than ordinary business operations and therefore may involve a greater risk of liability, particularly when a conflict of interests is found to exist. Our control of the general partner of WPZ may increase the possibility of claims of breach of fiduciary duties, including claims brought due to conflicts of interest (including conflicts of interest that may arise between WPZ, on the one hand, and its general partner and that general partner's affiliates, including us, on the other hand). Any liability resulting from such claims could be material.

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

Regulators and legislators continue to take a renewed look at accounting practices, financial disclosures, and companies' relationships with their independent public accounting firms. It remains unclear what new laws or regulations will be adopted, and we cannot predict the ultimate impact of that any such new laws or regulations could have. In addition, the Financial Accounting Standards Board, the SEC or FERC could enact new accounting standards or FERC orders that might impact how we are required to record revenues, expenses, assets, liabilities and equity. Any significant change in accounting standards or disclosure requirements could have a material adverse effect on our business, results of operations, and financial condition.

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

We currently own and might acquire and/or dispose of material energy-related investments and projects outside the United States. The economic and political conditions in certain countries where we have interests or in which we might explore development, acquisition or investment opportunities present risks of delays in construction and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments could make it more difficult to obtain nonrecourse project financing or other financing on suitable terms, could adversely affect the ability of certain customers to honor their obligations with respect to such projects or investments and could impair our ability to enforce our rights under agreements relating to such projects or investments.

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

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

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

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities have been constructed. As such, we are subject to the possibility of increased costs to retain necessary land use. In those instances in which we do not own the land on which our facilities are located, we obtain the rights to construct and operate our pipelines and gathering systems on land owned by third parties and governmental agencies for a specific period of time. In addition, some of our facilities cross Native American lands pursuant to rights-of-way of limited term. We may not have the right of eminent domain over land owned by Native American tribes. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, and financial condition and cash flows.

Risks Related to Strategy and Financing

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

Certain of our debt agreements contain various covenants that restrict or limit, among other things, our ability to grant liens to support indebtedness, merge or sell substantially all of our assets, make certain distributions during an event of default, 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. These covenants could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities and prevent us from engaging in certain transactions that might otherwise be considered beneficial to us. Our ability to comply with these covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our current assumptions about future economic conditions turn out to be incorrect or unexpected events occur, our ability to comply with these covenants may be significantly impaired.

Our failure to comply with the covenants in our debt agreements 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. Certain payment defaults or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements. For more information regarding our debt agreements, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Management's Discussion and Analysis of Financial Condition and Liquidity."

Our ability to repay, extend or refinance our existing debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to refinance existing debt obligations or obtain future credit will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to meet our debt service obligations or obtain future credit on favorable terms, if at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

Future disruptions in the global credit markets may make equity and debt markets less accessible, create a shortage in the availability of credit and lead to credit market volatility, which could disrupt our financing plans and limit our ability to grow.

In 2008, public equity markets experienced significant declines and global credit markets experienced a shortage in overall liquidity and a resulting disruption in the availability of credit. Future disruptions in the global financial marketplace, including the bankruptcy or restructuring of financial institutions, could make equity and debt markets inaccessible and adversely affect the availability of credit already arranged and the availability and cost of credit in the future. We have availability under our existing bank credit facilities, but our ability to borrow under those facilities could be impaired if one or more of our lenders fails to honor its contractual obligation to lend to us.

Adverse economic conditions could negatively affect our results of operations.

A slowdown in the economy has the potential to negatively impact our businesses in many ways. Included among these potential negative impacts are reduced demand and lower prices for our products and services, increased difficulty in collecting amounts owed to us by our customers and a reduction in our credit ratings (either due to tighter rating standards or the negative impacts described above), which could result in reducing our access to credit markets, raising the cost of such access or requiring us to provide additional collateral to our counterparties.

A downgrade of our credit ratings could impact our liquidity, access to capital and our costs of doing business, and independent third parties determine our credit ratings outside of our control.

A downgrade of our credit rating might increase our cost of borrowing and could require us to post collateral with third parties, negatively impacting our available liquidity. Our ability to access capital markets could also be limited by a downgrade of our credit rating and other disruptions. Such disruptions could include:

- Economic downturns;
- Deteriorating capital market conditions;
- Declining market prices for natural gas, NGLs and other commodities;
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies;
- The overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the ratings agencies, and no assurance can be given that we will maintain our current credit ratings or that our senior unsecured debt rating will be raised to investment grade by all of the credit rating agencies.

Risks Related to Regulations that Affect our Industry

Our gas pipelines could be subject to penalties and fines if they fail to comply with FERC regulations.

Our gas pipeline's transportation and storage operations are regulated by FERC. Should our gas pipelines fail to comply with all applicable FERC administered statutes, rules, regulations and orders, they could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the Natural Gas Act (NGA) to impose penalties for current violations of up to $1,000,000 per day for each violation. Any material penalties or fines imposed by FERC could have a material adverse impact on our gas pipeline business, financial condition, results of operations and cash flows.

The natural gas sales, transportation and storage operations of our gas pipelines are subject to regulation by the FERC, which could have an adverse impact on their ability to establish transportation and storage

rates that would allow them to recover the full cost of operating their respective pipelines, including a reasonable rate of return.

The natural gas sales, transmission and storage operations of the gas pipelines are subject to federal, state and local regulatory authorities. Specifically, their interstate pipeline transportation and storage service is subject to regulation by the FERC. The federal regulation extends to such matters as:

- Transportation and sale for resale of natural gas in interstate commerce;
- Rates, operating terms, and conditions of service, including initiation and discontinuation of service;
- The types of services the gas pipelines may offer their customers;
- Certification and construction of new facilities;
- Acquisition, extension, disposition or abandonment of facilities;
- Accounts and records;
- Depreciation and amortization policies;
- Relationships with affiliated companies who are involved in marketing functions of the natural gas business;
- Market manipulation in connection with interstate sales, purchases or transportation of natural gas.

Under the NGA, FERC has authority to regulate providers of natural gas pipeline transportation and storage services in interstate commerce, and such providers may only charge rates that have been determined to be just and reasonable by FERC. In addition, FERC prohibits providers from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or 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 pipeline business.

Unlike other interstate pipelines that own facilities in the offshore Gulf of Mexico, Transco charges its transportation customers a separate fee to access its offshore facilities. The separate charge is referred to as an "IT feeder" charge. The "IT feeder" rate is charged only when gas is actually transported on the facilities and typically it is paid by producers or marketers. Because the "IT feeder" rate is typically paid by producers and marketers, it generally results in netback prices to producers that are slightly lower than the netbacks realized by producers transporting on other interstate pipelines. This rate design disparity could result in producers bypassing Transco's offshore facilities in favor of alternative transportation facilities.

The rates, terms and conditions for interstate gas pipeline services are set forth in FERC-approved tariffs. Any successful complaint or protest against the rates of the gas pipelines could have an adverse impact on their revenues associated with providing transportation services. In addition, there is a risk that rates set by FERC in future rate cases filed by the gas pipelines will be inadequate to recover increases in operating costs or to sustain an adequate return on capital investments. There is also the risk that higher rates would cause their customers to look for alternative ways to transport natural gas.

We are subject to risks associated with climate change.

There is a growing belief that emissions of greenhouse gases (GHGs) may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks. For further information regarding risks to our business arising from climate change related legislation, please read the discussion below under "Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities and could exceed current expectations."

Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities and could exceed current expectations.

The risk of substantial environmental costs and liabilities is inherent in natural gas drilling and well completion, gathering, transportation, storage, processing and treating, and in the fractionation and storage of NGLs, and we may incur substantial environmental costs and liabilities in the performance of these types of operations. Our operations are subject to extensive federal, state and local environmental laws and regulations governing environmental protection, the discharge of materials into the environment and the security of chemical and industrial facilities. These laws include:

- Clean Air Act (CAA) and analogous state laws, which impose obligations related to air emissions;
- Clean Water Act (CWA), and analogous state laws, which regulate discharge of wastewaters from our facilities to state and federal waters;
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;
- Resource Conservation and Recovery Act (RCRA), and analogous state laws, which impose requirements for the handling and discharge of solid and hazardous waste from our facilities.

Various governmental authorities, including the U.S. Environmental Protection Agency (EPA) and analogous state agencies and the U.S. Department of Homeland Security, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations, and permits may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, and the issuance of injunctions limiting or preventing some or all of our operations.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to our handling of the products we gather, transport, process, fractionate and store, air emissions related to our operations, historical industry operations, waste disposal practices, and the prior use of flow meters containing mercury. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including CERCLA, RCRA, and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of natural gas and wastes on, under, or from our properties and facilities. Private parties, including the owners of properties through which our pipeline and gathering systems pass and facilities where our wastes are taken for reclamation or disposal, may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites we operate are located near current or former third-party hydrocarbon storage and processing operations, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our business, financial condition, results of operations and cash flows.

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.

In addition, legislative and regulatory responses related to GHGs and climate change creates the potential for financial risk. The U.S. Congress and certain states have for some time been considering various forms of legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. In addition, increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions.

Numerous states have announced or adopted programs to stabilize and reduce GHGs. In addition, on December 7, 2009, the EPA issued a final determination that six GHGs are a threat to public safety and welfare. This determination could lead to the direct regulation of GHG emissions in our industry under the EPA's interpretation of its authority and obligations under the CAA. The recent actions of the EPA and the passage of any federal or state climate change laws or regulations could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities, and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital.

Certain environmental and other groups have suggested that additional laws and regulations may be needed to more closely regulate the hydraulic fracturing process commonly used in natural gas production. Legislation to further regulate hydraulic fracturing has been proposed in Congress and the U.S. Department of Interior has announced plans to formalize obligations for disclosure of chemicals associated with hydraulic fracturing on federal lands. In addition, some state and local authorities have considered or formalized new rules related to hydraulic fracturing and enacted moratoria on such activities. We cannot predict whether any federal, state or local legislation or regulation will be enacted in this area and if so, what its provisions would be. If additional levels of reporting, regulation and permitting were required, our operations and those of our customers could be adversely affected.

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, and any new capital costs incurred to comply with such changes may not be recoverable under our regulatory rate structure or our customer contracts. In addition, new environmental laws and regulations might adversely affect our products and activities, including drilling, processing, fractionation, storage and transportation, as well as waste management and air emissions. For instance, federal and state agencies could impose additional safety requirements, any of which could affect our profitability.

If third-party pipelines and other facilities interconnected to our pipelines and facilities become unavailable to transport natural gas and NGLs or to treat natural gas, our revenues could be adversely affected.

We depend upon third-party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. Because we do not own these third-party pipelines or facilities, their continuing operation is not within our control. If these pipelines or other facilities were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to the pipelines or facilities, reduced operating pressures, lack of capacity, increased credit requirements or rates charged by such pipelines or facilities or other causes, we and our customers would have reduced capacity to transport, store or deliver natural gas or NGL products to end use markets or to receive deliveries of mixed NGLs, thereby reducing our revenues. Any temporary or permanent interruption at any key pipeline interconnect or in operations on third-party pipelines or facilities that would cause a material reduction in volumes transported on our pipelines or our gathering systems or processed, fractionated, treated or stored at our facilities could have a material adverse effect on our business, results of operations, financial condition and cash flows.

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

Existing regulations might be revised or reinterpreted, new laws and regulations might be adopted or become applicable to us, our facilities or our customers, and future changes in laws and regulations could have a material adverse effect on our financial condition, results of operations and cash flows. For example, several ruptures on third party pipelines have occurred recently. In response, various legislative and regulatory reforms associated with pipeline safety and integrity have been proposed, including reforms that would require increased periodic inspections, installation of additional valves and other equipment on our gas pipelines and subjecting additional pipelines (including gathering facilities) to more stringent regulation. Such reforms, if adopted, could significantly increase our costs.

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

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

Certain inquiries, investigations and court proceedings are ongoing. Adverse effects may 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 including environmental matters, 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.

The recently lifted drilling moratorium in the Gulf of Mexico and potentially more stringent regulations and permitting requirements on drilling in the Gulf of Mexico could adversely affect our results of operations, financial condition and cash flows.

The drilling moratorium in the Gulf of Mexico (in force from May to October 2010) impacted our production handling, gathering and transportation operations through production delays which reduced volumes of natural gas and oil delivered to our platform, pipeline and gathering facilities in 2010. In addition, the Bureau of Ocean Energy Management, Regulation and Enforcement continues to develop more stringent drilling and permitting requirements for producers in the Gulf of Mexico which could cause delays in production or new drilling. A significant decline or delay in production volumes in the Gulf of Mexico could adversely affect our operating results, financial condition and cash flows through reduced production handling activities, gathering and transportation volumes, processing activities or other midstream services.

Risks Related to Employees, Outsourcing of Noncore Support Activities, and Technology

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

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

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

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

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

Risks Related to Weather, other Natural Phenomena and Business Disruption

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

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

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

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

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

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

None.

Item 2. ***Properties***

We own property in 32 states plus the District of Columbia in the United States and in Argentina, Canada, Venezuela, and Colombia.

Williams Partners generally owns its facilities, although a substantial portion of the 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 is held as working interests in oil and gas leaseholds. In the Gulf of Mexico region, our Other segment owns a

5/6 interest in and is the operator of an ethane cracker at Geismar, Louisiana. It also owns ethane and propane pipeline systems and a refinery grade propylene splitter in Louisiana. Its Canadian operations include an oil sands off-gas processing plant located near Ft. McMurray, Alberta, an NGL/olefin fractionation facility at Redwater, Alberta, which is near Edmonton, Alberta, as well as a new butylene/butane splitter and hydro-treating facility.

Item 3. ***Legal Proceedings***

The information called for by this item is provided in Note 16 of the Notes to Consolidated Financial Statements of this report, which information is incorporated by reference into this item.

Executive Officers of the Registrant

The name, age, period of service, and title of each of our executive officers as of February 24, 2011, are listed below.

Alan S. Armstrong .... Director, Chief Executive Officer, and President
Age: 48

Position held since January 2011.

Mr. Armstrong became a director, Chief Executive Officer, and President effective January 3, 2011. From February 2002 until January 2011 he was Senior Vice President, Midstream and acted as President of our Midstream business. From 1999 to February 2002, Mr. Armstrong was Vice President, Gathering and Processing for Midstream. From 1998 to 1999 he was Vice President, Commercial Development for Midstream. Mr. Armstrong serves as Chairman of the Board and Chief Executive Officer of Williams Partners GP LLC, the general partner of WPZ, where he was formerly Senior Vice President and a director from February 2010 and February 2005, respectively.

Randall L. Barnard .... Senior Vice President, Gas Pipeline
Age: 52

Position held since February 2011.

Mr. Barnard acts as President of our Gas Pipeline business. Mr. Barnard served as Vice President of Natural Gas Market Development from July 2010 to February 2011. From April 2002 to July 2010, Mr. Barnard was Senior Vice President of Operations and Technical Service for Williams Gas Pipeline. From September 2000 to April 2002, he served as President of Williams International and Vice President and General Manager of Williams, and was a director and CEO of Apco Oil and Gas International Inc., formerly Apco Argentina. From June 1997 to September 2000, Mr. Barnard was General Manager of Williams International in Venezuela. Mr. Barnard is a director and Senior Vice President, Gas Pipeline, of Williams Partners GP LLC, the general partner of WPZ, Chairman of the Board of the Gas Technology Institute and is Vice Chair of the Common Ground Alliance.

James J. Bender .... Senior Vice President and General Counsel
Age: 54

Position held since December 2002.

Prior to joining us, Mr. Bender was Senior Vice President and General Counsel with NRG Energy, Inc., a position held since June 2000, prior to which he was Vice President, General Counsel and Secretary of NRG Energy Inc. NRG Energy, Inc. filed a voluntary bankruptcy petition during 2003 and its plan of reorganization was approved in December 2003. Mr. Bender has served as the General Counsel of Williams Partners GP LLC, the general partner of WPZ since February 2005 and was General Counsel of Williams Pipeline GP LLC, the general partner of WMZ from August 2007 until its merger with WPZ in August 2010.

Donald R. Chappel . . . . Senior Vice President and Chief Financial Officer
Age: 59

Position held since April 2003.

Prior to joining us, Mr. Chappel held various financial, administrative and operational leadership positions. Mr. Chappel also serves as Chief Financial Officer and a director of Williams Partners GP LLC, the general partner of WPZ. He was Chief Financial Officer from August 2007 and a director from January 2008 of Williams Pipeline GP LLC, the general partner of WMZ until its merger with WPZ in August 2010. Mr. Chappel is a director of SUPERVALU, Inc., Energy Insurance Mutual Limited, the Children's Hospital Foundation at St. Francis and the Family & Children Services of Oklahoma.

Robyn L. Ewing. . . . . Senior Vice President and Chief Administrative Officer
Age: 55

Position held since April 2008.

From 2004 to 2008 Ms. Ewing was Vice President of Human Resources. Prior to joining Williams, Ms. Ewing worked at MAPCO, which merged with Williams in April 1998. She began her career with Cities Service Company in 1976.

Ralph A. Hill . . . . Senior Vice President, Exploration & Production
Age: 51

Position held since December 1998.

Mr. Hill acts as President of our Exploration & Production business unit. He was Vice President of the Exploration & Production business from 1993 to 1998 as well as Senior Vice President Petroleum Services from 1998 to 2003. Mr. Hill serves as a director of Apco Oil and Gas International Inc. and Petrolera Entre Lomas S.A.

Rory L. Miller . . . . Senior Vice President, Midstream
Age: 50

Position held since January 2011.

Mr. Miller acts as President of the Williams Partners midstream business. He was a Vice President of the Williams Partners midstream business from May 2004 to December 2011. Mr. Miller also serves as a director and Senior Vice President, Midstream of Williams Partners GP LLC, the general partner of WPZ.

Ted T. Timmermans . . . . Vice President, Controller, and Chief Accounting Officer
Age: 54

Position held since July 2005.

Mr. Timmermans has served as Vice President, Controller & Chief Accounting Officer of Williams since July 2005. He served as Assistant Controller of Williams from April 1998 to July 2005. Mr. Timmermans is also Vice President, Controller & Chief

Accounting Officer of Williams Partners GP LLC, the general partner of WPZ and served as Chief Accounting Officer of Williams Pipeline Partners GP LLC, the general partner of WMZ from January 2008 until its merger with WPZ in August 2010.

Phillip D. Wright . . . . Senior Vice President, Corporate Development
Age: 55

Position held since February 2011.

Mr. Wright has served as Senior Vice President, Corporate Development since February 2011. He served as Senior Vice President, Gas Pipeline and acted as President of our Gas Pipeline business from January 2005 to February 2011. From October 2002 to January 2005, he 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, LLC. From 1996 until September 2001, he was Senior Vice President, Enterprise Development and Planning for our energy services group. Mr. Wright served as a director and Chief Operating Officer of Williams Pipeline GP LLC, the general partner of WMZ until its merger with WPZ in August 2010 and was a director and Senior Vice President, Gas Pipeline, of Williams Partners GP LLC, the general partner of WPZ from January 2010 to February 2011.

PART II

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

Our common stock is listed on the New York Stock Exchange under the symbol "WMB." At the close of business on February 21, 2011, we had approximately 10,032 holders of record of our common stock. The high and low sales price ranges (New York Stock Exchange composite transactions) and dividends declared by quarter for each of the past two years are as follows:

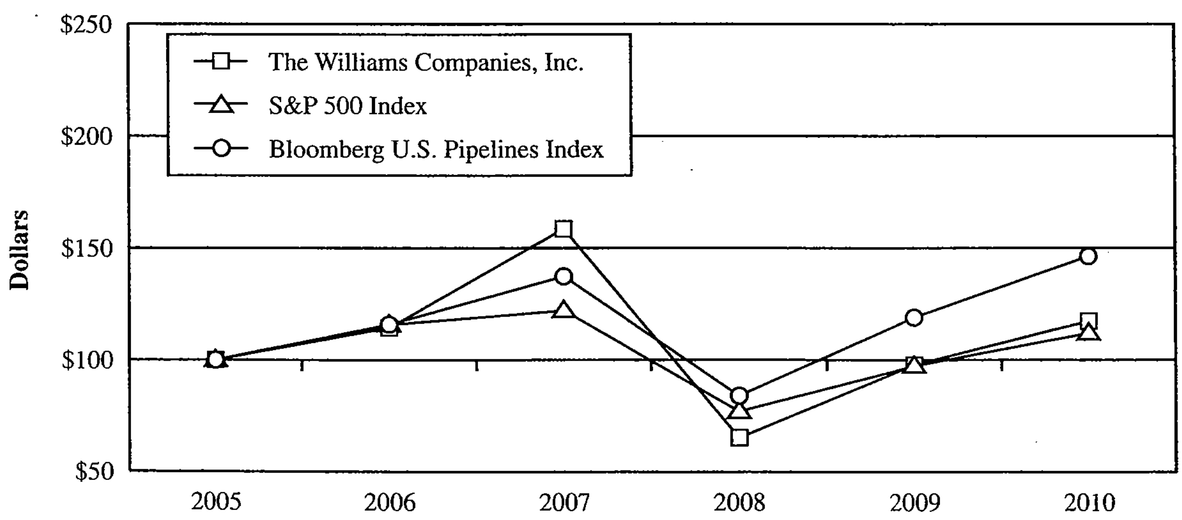
	2010			2009		
Quarter	**High**	**Low**	**Dividend**	**High**	**Low**	**Dividend**
1st	$23.76	$19.51	$ 0.11	$16.87	$ 9.52	$0.11
2nd	$24.66	$18.16	$0.125	$17.99	$11.30	$0.11
3rd	$21.00	$17.53	$0.125	$19.21	$13.59	$0.11
4th	$24.89	$18.88	$0.125	$21.54	$16.57	$0.11

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

Performance Graph

Set forth below is a line graph comparing our cumulative total stockholder return on our common stock (assuming reinvestment of dividends) with the cumulative total return of the S&P 500 Stock Index and the Bloomberg U.S. Pipeline Index for the period of five fiscal years commencing January 1, 2006. The Bloomberg U.S. Pipeline Index is composed of El Paso, Enbridge, Spectra Energy, TransCanada Corp. and Williams. The graph below assumes an investment of $100 at the beginning of the period.

Cumulative Total Shareholder Return



	2005	2006	2007	2008	2009	2010
The Williams Companies, Inc.	100.0	114.4	158.6	65.3	97.8	117.4
S&P 500 Index	100.0	115.8	122.1	77.0	97.3	112.0
Bloomberg U.S. Pipelines Index	100.0	115.9	137.4	84.0	119.0	146.3

Item 6. *Selected Financial Data*

The following financial data at December 31, 2010 and 2009, and for each of the three years in the period ended December 31, 2010, should be read in conjunction with the other financial information included in Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations* and Part II, Item 8, *Financial Statements and Supplementary Data* of this Form 10-K. All other financial data has been prepared from our accounting records.

	2010	2009	2008	2007	2006
		(Millions, except per-share amounts)			
Revenues	$ 9,616	$ 8,255	$11,890	$10,239	$ 9,144
Income (loss) from continuing operations(1)	(916)	584	1,467	910	366
Income (loss) from discontinued operations(2)	(6)	(223)	125	170	(17)
Amounts attributable to The Williams Companies, Inc.:					
Income (loss) from continuing operations	(1,091)	438	1,306	829	332
Income (loss) from discontinued operations	(6)	(153)	112	161	(23)
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	(1.87)	.75	2.21	1.37	.55
Income (loss) from discontinued operations	(0.01)	(0.26)	0.19	0.26	(0.04)
Total assets at December 31	24,972	25,280	26,006	25,061	25,402
Short-term notes payable and long-term debt due within one year at December 31	508	17	18	108	358
Long-term debt at December 31	8,600	8,259	7,683	7,580	7,410
Stockholders' equity at December 31	7,288	8,447	8,440	6,375	6,073
Cash dividends declared per common share	0.485	.44	.43	.39	.345

(1) Loss from continuing operations for 2010 includes $648 million of pre-tax costs associated with our restructuring, as well as approximately $1.7 billion of impairment charges related to goodwill and certain properties at Exploration & Production. See Note 4 of Notes to Consolidated Financial Statements for further discussion of asset sales, impairments, and other accruals in 2010, 2009, and 2008. Income from continuing operations for 2006 includes a $73 million charge for a litigation contingency and a $167 million charge for a securities litigation settlement and related costs.

(2) See Note 2 of Notes to Consolidated Financial Statements for the analysis of the 2010, 2009, and 2008 income (loss) from discontinued operations. The discontinued operations results for 2007 includes our former power business and our discontinued Venezuela operations. The discontinued operations results for 2006 includes our former power business, discontinued Venezuela operations, as well as amounts associated with our former chemical fertilizer business, a former exploration business, our former Alaska refinery, and our former distributive power business.

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

General

We are primarily an integrated natural gas company engaged in finding, producing, gathering, processing, and transporting natural gas. Our operations are located principally in the United States and are organized into the following segments as of December 31, 2010: Williams Partners, Exploration & Production, and Other. (See Note 1 of Notes to Consolidated Financial Statements and Part I, Item 1 for further discussion of these segments.)

Unless indicated otherwise, the following discussion and analysis of critical accounting estimates, 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.

Change in Structure and Dividend Increase

On February 16, 2011, we announced that our Board of Directors approved pursuing a plan to separate the company into two standalone, publicly traded corporations. The plan calls for the separation of our exploration and production business into a publicly traded company via an initial public offering of up to 20 percent of our interest in the third quarter of 2011. We intend to complete the offering so that it preserves our ability to complete a tax-free spinoff of our remaining ownership in the exploration and production business to Williams' shareholders in 2012, after which Williams would continue as a premier natural gas infrastructure company. We retain the discretion to determine whether and when to execute the spinoff.

Additionally, we intend to increase the quarterly dividend paid to our shareholders, with an initial increase of 60 percent (to $0.20 per share), for the first quarter of 2011 payable in June 2011.

Management believes these actions will serve to enhance the growth potential and overall valuation of our assets.

Overview of 2010

The effects of the severe economic recession during late 2008 and 2009 have eased during 2010. Crude oil and NGL prices have returned to attractive levels, but natural gas prices have remained low. Natural gas prices have remained low and forward natural gas prices have declined, primarily as a result of significant increases in near- and long-term supplies, which have outpaced near-term demand growth. The decline in forward natural gas prices contributed significantly to impairments recorded by our Exploration & Production segment in the third quarter of 2010. However, lower natural gas prices, along with strong NGL prices and ethane demand, contributed to improved results in our midstream businesses. Abundant and low-cost natural gas reserves in the United States are driving strong demand for midstream and pipeline infrastructure. Objectives and highlights of our plan for 2010 include:

Objectives	Highlights
Continuing to invest in our gathering and processing and interstate natural gas pipeline systems.	We invested $1 billion in capital and investment expenditures in our midstream businesses and also invested $473 million in capital expenditures in our gas pipelines during 2010.
Continuing to invest in our natural gas production development.	We invested $2.8 billion in drilling activity and acquisitions in Exploration & Production, including $1.7 billion related to acquisitions in the Bakken and Marcellus Shale areas.
Retaining the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions, as well as seizing attractive opportunities.	During 2010, our Williams Partners and Exploration & Production segments seized growth opportunities to expand in the Marcellus Shale, while Exploration & Production further diversified into oil production with an acquisition in North Dakota's Bakken Shale. (See further discussion in Other Significant 2010 Events.) These expenditures were funded through cash flow from operations, debt and equity offerings at WPZ, and cash on hand, while maintaining our desired level of liquidity of at least $1 billion from *cash and cash equivalents* and unused revolving credit facilities.

Our 2010 income (loss) from continuing operations attributable to The Williams Companies, Inc. changed unfavorably by $1.5 billion compared to 2009. This decrease is primarily reflective of a $1 billion full impairment charge related to goodwill at Exploration & Production and $678 million of pre-tax charges associated with impairments of certain producing properties and acquired unproved reserves at Exploration & Production during the third quarter of 2010. Additionally, we had $648 million of pre-tax costs associated with our 2010 restructuring, including $606 million of early debt retirement costs. Partially offsetting these costs is the impact of an improved energy commodity price environment in 2010 compared to 2009. See additional discussion in Results of Operations.

Our net cash provided by operating activities for 2010 increased $79 million compared to 2009, primarily due to the improvement in the energy commodity price environment during the year. See additional discussion in Management's Discussion and Analysis of Financial Condition and Liquidity.

Other Significant 2010 Events

On February 17, 2010, we completed a strategic restructuring that involved contributing certain of our wholly and partially owned subsidiaries to WPZ, our consolidated master limited partnership, and restructuring our debt (see Note 11 of Notes to Consolidated Financial Statements).

In May 2010, Exploration & Production announced a major acreage acquisition in the Marcellus Shale located in northeast Pennsylvania. In July 2010, the purchase was completed for $599 million, including closing adjustments. (See Results of Operations — Segments, Exploration & Production.)

On May 24, 2010, WPZ and WMZ entered into a merger agreement providing for the merger of WMZ and WPZ. On August 31, 2010, the WMZ unitholders approved the proposed merger between the two master limited partnerships and the merger was completed.

In July 2010, we notified our partner in the Overland Pass Pipeline Company LLC (OPPL) of our election to exercise our option to purchase an additional ownership interest, which provides us with a 50 percent ownership interest in OPPL, for approximately $424 million. This transaction was completed on September 9, 2010, primarily with proceeds from WPZ's credit facility. (See Results of Operations — Segments, Williams Partners.) Additionally, WPZ completed an equity offering resulting in net proceeds of $437 million, which were used to reduce the borrowing under WPZ's credit facility.

In October 2010, we filed an application with the Federal Energy Regulatory Commission (FERC) to upgrade compressor facilities and expand our existing natural gas transmission system from Alabama to markets as far north as North Carolina. The cost of the project is estimated to be $219 million. The project is expected to be phased into service in September 2012 and June 2013, with an increase in capacity of 225 Mdt/d.

In November 2010, WPZ acquired a business from Exploration & Production represented by certain gathering and processing assets in Colorado's Piceance basin, for $702 million in cash, approximately 1.8 million of WPZ common units and an increase in the capital account of its general partner to allow us to maintain our 2 percent general partner interest. (See Note 1 of Notes to Consolidated Financial Statements.)

In November 2010, WPZ completed a public offering of $600 million of its 4.125 percent senior notes due 2020. WPZ used the net proceeds from the offering to fund a portion of the cash consideration paid for the previously described gathering and processing assets in the Piceance basin. (See further discussion in Results of Operations — Segments, Williams Partners.)

In December 2010, WPZ acquired a midstream business in Pennsylvania's Marcellus Shale for $150 million. (See further discussion in Results of Operations — Segments, Williams Partners.)

In December 2010, Exploration & Production acquired a company that holds a major acreage position (approximately 85,800 net acres) in North Dakota's Bakken Shale oil play that will diversify our interests into light, sweet crude oil production. The purchase price was approximately $949 million, including closing adjustments.

In December 2010, WPZ completed a public offering of 8 million of its common units, representing limited-partner interests. WPZ used the net proceeds from the common unit public offering for repayment of a $200 million borrowing under the partnership's credit facility, as well as funding a portion of the consideration for the acquisition of midstream assets in Pennsylvania's Marcellus Shale. We made a cash contribution to WPZ in order to maintain our 2 percent general partner interest in the partnership. As a result of the offering, our limited partner interest in the partnership was reduced to 73 percent. See additional discussion in Management's Discussion and Analysis of Financial Condition and Liquidity.

Outlook for 2011

We believe we are well positioned to execute on our 2011 business plan and to capture attractive growth opportunities. Economic and commodity price indicators for 2011 and beyond reflect continued improvement in the economic environment. However, given the potential volatility of these measures, it is reasonably possible that the economy could worsen and/or commodity prices could decline, negatively impacting future operating results and increasing the risk of nonperformance of counterparties or impairments of long-lived assets.

As a result of our 2010 restructuring, as previously discussed, we are better positioned to drive additional organic growth and aggressively pursue value-adding growth opportunities. Our structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions.

We continue to operate with a focus on increasing Economic Value Added® (EVA®)[1] and invest in our businesses in a way that meets customer needs and enhances our competitive position by:

- Continuing to invest in and grow our gathering and processing, interstate natural gas pipeline systems, and natural gas and oil drilling;

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[1] Economic Value Added® (EVA®) is a registered trademark of Stern, Stewart & Co. This tool considers both financial earnings and a cost of capital in measuring performance. We look for opportunities to improve EVA® because we believe there is a strong correlation between EVA® improvement and creation of shareholder value.

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

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

- Lower than anticipated energy commodity prices;
- Lower than expected levels of cash flow from operations;
- Availability of capital;
- Counterparty credit and performance risk;
- Decreased drilling success at Exploration & Production;
- Decreased volumes from third parties served by our midstream businesses;
- General economic, financial markets, or industry downturn;
- Changes in the political and regulatory environments;
- Physical damages to facilities, especially damage to offshore facilities by named windstorms for which our aggregate insurance policy limit is $75 million in the event of a material loss.

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

Critical Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions. We have reviewed the selection, application, and disclosure of these critical accounting estimates with our Audit Committee. We believe that the nature of these estimates and assumptions is material due to the subjectivity and judgment necessary, or the susceptibility of such matters to change, and the impact of these on our financial condition or results of operations.

Impairments of Goodwill and Long-Lived Assets

We have assessed goodwill for impairment annually as of the end of the year and we have performed interim assessments of goodwill if impairment triggering events or circumstances were present. One such triggering event is a significant decline in forward natural gas prices. During the first and second quarter of 2010, we evaluated the impact of declines in forward gas prices across all future production periods and determined that the impact was not significant enough to warrant a full impairment review. Forward natural gas prices through 2025 used in these prior analyses had declined less than 10 percent, on average, from December 31, 2009 through March 31, 2010 and June 30, 2010. During the third quarter of 2010, these forward natural gas prices through 2025 declined an additional 19 percent for a total year-to-date decline of more than 22 percent on average through September 30, 2010. Based on forward prices as of September 30, 2010, we evaluated the impact of this decline across all future production periods and determined that a full impairment review was warranted.

As a result, we evaluated our goodwill of approximately $1 billion resulting from a 2001 acquisition at Exploration & Production related to its domestic natural gas production operations (the reporting unit). Our impairment evaluation of goodwill first considered our management's estimate of the fair value of the reporting unit compared to its carrying value, including goodwill. If the carrying value of the reporting unit exceeded its fair value, a computation of the implied fair value of the goodwill was compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeded the implied fair value of that goodwill, an impairment loss was recognized in the amount of the excess. Because quoted market prices were not available for the reporting unit, management applied reasonable judgments (including market supported assumptions when available) in estimating the fair value for the reporting unit. We estimated the fair value of the reporting unit on a stand-alone basis and also considered our market capitalization and third party estimates in corroborating our estimate of the fair value of the reporting unit.

The fair value of the reporting unit was estimated primarily by valuing proved and unproved reserves. We use an income approach (discounted cash flows) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves include reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired.

In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its fair value. We then determined that the implied fair value of the goodwill was zero. As a result, we recognized a full $1 billion impairment charge related to Exploration & Production's goodwill. See Note 4 and Note 14 of Notes to Consolidated Financial Statements for additional discussion and significant inputs into the fair value determination.

We evaluate our long-lived assets for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value. Our computations utilize judgments and assumptions that include the estimated fair value of the asset, undiscounted future cash flows, discounted future cash flows, and the current and future economic environment in which the asset is operated.

As a result of significant declines in forward natural gas prices during the third quarter of 2010, we assessed Exploration & Production's natural gas producing properties and acquired unproved reserve costs for impairment using estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of natural gas reserves quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and our estimate of an applicable discount rate commensurate with risk of the underlying cash flow estimates. The assessment performed at September 30, 2010 identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recognized a $678 million impairment charge. See Note 4 and Note 14 of Notes to Consolidated Financial Statements for additional discussion and significant inputs into the fair value determination.

In addition to those long-lived assets described above for which impairment charges were recorded, certain others were reviewed for which no impairment was required. These reviews included Exploration & Production's other domestic producing properties and acquired unproved reserve costs, and utilized inputs generally consistent with those described above. Judgments and assumptions are inherent in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements. For Exploration & Production's other producing assets reviewed, but for which impairment charges were not recorded, we estimate that approximately 10 percent could be at risk for impairment if forward prices across all future periods decline by approximately 8 to 11 percent, on average, as compared to the forward prices at December 31, 2010. A substantial portion of the remaining carrying value of these other assets (primarily related to Exploration & Production's assets in the Piceance basin) could be at risk for impairment if forward prices across all future periods decline by at least 30 percent, on average, as compared to the prices at December 31, 2010.

Accounting for Derivative Instruments and Hedging Activities

We review our energy contracts to determine whether they are derivatives or contain derivatives. We further assess the appropriate accounting method for any derivatives identified, which could include:

- Qualifying for and electing cash flow hedge accounting, which recognizes changes in the fair value of the derivative in other comprehensive income (to the extent the hedge is effective) until the hedged item is recognized in earnings;
- Qualifying for and electing accrual accounting under the normal purchases and normal sales exception; or
- Applying mark-to-market accounting, which recognizes changes in the fair value of the derivative in earnings.

If cash flow hedge accounting or accrual accounting is not applied, a derivative is subject to mark-to-market accounting. Determination of the accounting method involves significant judgments and assumptions, which are further described below.

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

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

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

Since our energy derivative contracts could be accounted for in three different ways, two of which are elective, our accounting method could be different from that used by another party for a similar transaction. Furthermore, the accounting method may influence the level of volatility in the financial statements associated with changes in the fair value of derivatives, as generally depicted below:

	Consolidated Statement of Operations		Consolidated Balance Sheet	
Accounting Method	**Drivers**	**Impact**	**Drivers**	**Impact**
Accrual Accounting	Realizations	Less Volatility	None	No Impact
Cash Flow Hedge Accounting	Realizations & Ineffectiveness	Less Volatility	Fair Value Changes	More Volatility
Mark-to-Market Accounting	Fair Value Changes	More Volatility	Fair Value Changes	More Volatility

Our determination of the accounting method does not impact our cash flows related to derivatives.

Additional discussion of the accounting for energy contracts at fair value is included in Notes 1 and 15 of Notes to Consolidated Financial Statements.

Oil- and Gas-Producing Activities

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

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

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, approximately 94 percent of our domestic reserve estimates are audited by independent experts. (See Part I, Item 1 for further discussion.) The data may change substantially over time as a result of numerous factors, including additional development cost and 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. Such changes could trigger an impairment of our oil and gas properties and have an impact on our *depreciation, depletion, and amortization* expense prospectively. For example, a change of approximately 10 percent in our total oil and gas reserves could change our annual *depreciation, depletion, and amortization* expense between approximately $77 million and $94 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. Significant unfavorable changes in the forward price curve could result in an impairment of our oil and gas properties.

Contingent Liabilities

We record liabilities for estimated loss contingencies, including environmental matters, when we assess that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are generally reflected in income when 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. Areas of significance include certain royalty-related and other litigated matters, as well as environmental matters. 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 16 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. When assessing the need for a valuation allowance, we consider 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. 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, including the impact of organizational or structural changes.

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. We evaluate the liability associated with our various filing positions by applying the two step process of recognition and measurement. The ultimate disposition of these contingencies could have a significant impact on operating results and net cash flows. To the extent we were to prevail in matters for which accruals have been established or were required to pay amounts in excess of our accrued liability, our effective tax rate in a given financial statement period may be materially impacted.

See Note 5 of Notes to Consolidated Financial Statements for additional information.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Net periodic benefit expense and obligations for these plans are impacted by various estimates and assumptions. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates, expected rate of compensation increase, health care cost trend rates, and employee demographics, including retirement age and mortality. These assumptions are reviewed annually and adjustments are made as needed. The assumptions utilized to compute expense and the benefit obligations are shown in Note 7 of Notes to Consolidated Financial Statements.

The following table presents the estimated increase (decrease) in net periodic benefit expense and obligations resulting from a one-percentage-point change in the specified assumption.

	Benefit Expense		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Millions)			
Pension benefits:				
Discount rate	$(10)	$11	$(133)	$158
Expected long-term rate of return on plan assets	(10)	10	—	—
Rate of compensation increase	3	(3)	14	(12)
Other postretirement benefits:				
Discount rate	(3)	3	(35)	43
Expected long-term rate of return on plan assets	(2)	2	—	—
Assumed health care cost trend rate	5	(4)	39	(32)

Our expected long-term rates of return on plan assets, as determined at the beginning of each fiscal year, are based on the average rate of return expected on the funds invested in the plans. We determine our long-term expected rate of return on plan assets using our expectations of capital market results, which includes an analysis of historical results as well as forward-looking projections. These capital market expectations are based on a long-term period of at least ten years and consider our investment strategy and mix of assets, which is weighted toward domestic and international equity securities. We develop our expectations using input from several external sources, including consultation with our third-party independent investment consultant. The forward-looking capital market projections are developed using a consensus of economists' expectations for inflation, GDP growth, and dividend yield along with expected changes in risk premiums. The capital market return projections for specific asset classes in the investment portfolio are then applied to the relative weightings of the asset classes in the investment portfolio. The resulting rate is an estimate of future results and, thus, likely to be different than actual results.

The capital markets continued to improve in 2010 and the benefit plans' assets reflect this improvement. While the 2010 investment performance was greater than our expected rates of return, the expected rates of return on plan assets are long-term in nature and are not significantly impacted by short-term market performance. Changes to our asset allocation would also impact these expected rates of return. Our expected long-term rate of return on plan assets used for our pension plans had been 7.75 percent since 2006. In 2010, we reduced our expected long-term rate of return on pension plan assets to 7.5 percent. This reduction was implemented due to changes in long-term capital market expectations and our intent to slightly reduce the equity exposure and increase the fixed income exposure in the investment portfolio. The 2010 actual return on plan assets for our pension plans was a gain of approximately 12.9 percent. The ten-year average rate of return on pension plan assets through December 2010 was approximately 3.3 percent and is largely affected by the approximately 34.1 percent loss experienced in 2008.

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

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

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

Fair Value Measurements

A limited amount of our energy derivative assets and liabilities trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. At December 31, 2010, less than 1 percent of our energy derivative assets and liabilities measured at fair value on a recurring basis are included in Level 3. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value for our energy derivative assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our energy derivative liabilities. The determination of the fair value of our energy derivative liabilities does not consider noncash collateral credit enhancements. For net derivative assets, we apply a credit spread, based on the credit rating of the counterparty, against the net derivative asset with that counterparty. For net derivative liabilities we apply our own credit rating. We derive the credit spreads by using the corporate industrial credit curves for each rating category and building a curve based on certain points in time for each rating category. The spread comes from the discount factor of the individual corporate curves versus the discount factor of the LIBOR curve. At December 31, 2010, the credit reserve is less than $1 million on both our net derivative assets and net derivative liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

At December 31, 2010, 89 percent of the fair value of our derivatives portfolio expires in the next 12 months and more than 99 percent expires in the next 24 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

The instruments included in Level 3 at December 31, 2010, consist of natural gas index transactions that are used to manage the physical requirements of our Exploration & Production segment. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices.

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

For the years ended December 31, 2010 and 2009, we recognized impairments of certain assets that were measured at fair value on a nonrecurring basis. These impairment measurements are included in Level 3 as they include significant unobservable inputs, such as our estimate of future cash flows and the probabilities of alternative scenarios. (See Note 14 of Notes to Consolidated Financial Statements.)

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2010	$ Change from 2009*	% Change from 2009*	2009	$ Change from 2008*	% Change from 2008*	2008
				(Millions)			
Revenues	$ 9,616	+1,361	+16%	$8,255	− 3,635	−31%	$11,890
Costs and expenses:							
Costs and operating expenses	7,185	−1,104	−18%	6,081	+ 2,695	+31%	8,776
Selling, general and administrative expenses	498	+14	+3%	512	−8	−2%	504
Impairments of goodwill and long-lived assets	1,692	−1,672	NM	20	+ 133	+87%	153
Other (income) expense — net	(24)	+21	NM	(3)	−222	−99%	(225)
General corporate expenses	221	−57	−35%	164	−15	−10%	149
Total costs and expenses	9,572			6,774			9,357
Operating income (loss)	44			1,481			2,533
Interest accrued — net	(581)	+4	+1%	(585)	−8	−1%	(577)
Investing income — net	209	+163	NM	46	−143	−76%	189
Early debt retirement costs	(606)	−605	NM	(1)	—	—	(1)
Other income (expense) — net	(12)	−14	NM	2	+ 2	NM	—
Income (loss) from continuing operations before income taxes	(946)			943			2,144
Provision (benefit) for income taxes	(30)	+389	NM	359	+ 318	+47%	677
Income (loss) from continuing operations	(916)			584			1,467
Income (loss) from discontinued operations	(6)	+217	+97%	(223)	−348	NM	125
Net income (loss)	(922)			361			1,592
Less: Net income attributable to noncontrolling interests	175	−99	−130%	76	+ 98	+56%	174
Net income (loss) attributable to The Williams Companies, Inc.	$(1,097)			$ 285			$ 1,418

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

2010 vs. 2009

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

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

Impairments of goodwill and long-lived assets in 2010 primarily includes a $1 billion impairment of goodwill and $678 million of impairments of certain producing properties and acquired unproved reserves at Exploration & Production.

Impairments of goodwill and long-lived assets in 2009 includes $20 million impairment of certain producing properties and acquired unproved reserves at Exploration & Production.

Other (income) expense — net within *operating income (loss)* in 2010 includes:

- $18 million of involuntary conversion gains at Williams Partners due to insurance recoveries that are in excess of the carrying value of assets;
- A $12 million gain on the sale of certain assets at Williams Partners;
- A $10 million accrual of a regulatory liability related to overcollection of certain employee expenses at Williams Partners.

Other (income) expense — net within *operating income (loss)* in 2009 includes:

- A $40 million gain on the sale of our Cameron Meadows NGL processing plant at Williams Partners;
- $32 million of penalties from the early termination of certain drilling rig contracts at Exploration & Production.

General corporate expenses in 2010 includes $45 million of transaction costs associated with our strategic restructuring transaction.

The unfavorable change in *operating income (loss)* is primarily due to $1.7 billion of impairment charges in 2010 at Exploration & Production and $45 million of transaction costs in 2010 associated with our strategic restructuring transaction. The unfavorable change is partially offset by an improved energy commodity price environment in 2010 compared to 2009 and the favorable change in *other (income) expense — net*.

The increase in *investing income — net* is primarily due to the absence of a $75 million impairment charge in 2009 and a $43 million gain in 2010 on the sale of our 50 percent interest in Accroven at Other, a $27 million increase in equity earnings, primarily at Williams Partners, and the absence of an $11 million impairment charge in 2009 of a cost-based investment at Exploration & Production.

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

Provision (benefit) for income taxes changed favorably primarily due to the pre-tax loss in 2010 compared to pre-tax income in 2009. See Note 5 of Notes to Consolidated Financial Statements for a reconciliation of the effective tax rates compared to the federal statutory rate for both years.

See Note 2 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations*.

Net income attributable to noncontrolling interests increased reflecting higher results, primarily at WPZ, due to an improved energy commodity price environment in 2010 compared to 2009 as well as the impact of the first-quarter 2009 impairments and related charges associated with our discontinued Venezuela operations.

2009 vs. 2008

Our consolidated results in 2009 declined significantly compared to 2008. These results reflect a rapid decline in energy commodity prices that began in the fourth quarter of 2008 as a result of the weakened economy. Energy commodity prices generally improved during 2009, but not to levels experienced early in 2008.

The decrease in *revenues* is primarily due to decreased gas management and production revenues at Exploration & Production, reflecting a decrease in average natural gas prices, partially offset by an increase in production volumes sold. NGL production and marketing revenues at Williams Partners, as well as NGL and olefin production revenues at Other, also decreased reflecting lower average prices.

The decrease in *costs and operating expenses* is primarily due to decreased costs at Exploration & Production reflecting a decrease in average natural gas prices associated with gas management activities, as well as decreased marketing purchases and decreased costs associated with our NGL production businesses at Williams Partners. In addition, NGL and olefin production costs at Other decreased primarily due to lower average per-unit feedstock costs.

Impairments of goodwill and long-lived assets in 2008 includes $143 million of impairments of certain producing properties at Exploration & Production and $10 million of impairments of certain gathering and transportation assets at Williams Partners.

Other (income) expense — net within *operating income (loss)* in 2008 includes:

- Gain of $148 million on the sale of our Peru interests at Exploration & Production;
- Net gains of $39 million on foreign currency exchanges at Other;
- Income of $32 million related to the partial settlement of our Gulf Liquids litigation at Other;
- Gain of $10 million on the sale of certain south Texas assets at Williams Partners;
- Income of $17 million resulting from involuntary conversion gains at Williams Partners;
- Expense of $23 million related to project development costs at Williams Partners.

General corporate expenses increased primarily due to an increase in employee-related expenses, partially offset by a decrease in outside services.

The decrease in *operating income (loss)* generally reflects an overall unfavorable energy commodity price environment in 2009 compared to 2008 and other changes as previously discussed.

The decrease in *investing income — net* is primarily due to a $75 million impairment charge in 2009 of our 50 percent interest in Accroven at Other and an $11 million impairment charge in 2009 of a cost-based investment at Exploration & Production. (See Note 3 of Notes to Consolidated Financial Statements.) A decrease in interest income, primarily due to lower average interest rates in 2009 compared to 2008, also contributed to the decrease in *investing income — net.*

Provision (benefit) for income taxes changed favorably primarily due to lower pre-tax income. See Note 5 of Notes to Consolidated Financial Statements for a reconciliation of the effective tax rates compared to the federal statutory rate for both years.

See Note 2 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations.*

Net income attributable to noncontrolling interests decreased reflecting the first-quarter 2009 impairments and related charges associated with our discontinued Venezuela operations (see Note 2 of Notes to Consolidated Financial Statements) and the decline in WPZ's operating results primarily driven by lower NGL margins.

Results of Operations — Segments

Williams Partners

Our Williams Partners segment includes WPZ, our consolidated master limited partnership, which includes two interstate natural gas pipelines, as well as investments in natural gas pipeline-related companies, which serve regions from the San Juan basin in northwestern New Mexico and southwestern Colorado to Oregon and Washington and from the Gulf of Mexico to the northeastern United States. WPZ also includes natural gas gathering and processing and treating facilities and oil gathering and transportation facilities located primarily in the Rocky Mountain and Gulf Coast regions of the United States. As of December 31, 2010, we currently own approximately 75 percent of the interests in WPZ, including the interests of the general partner, which is wholly owned by us, and incentive distribution rights.

Williams Partners' ongoing strategy is to safely and reliably operate large-scale, interstate natural gas transmission and midstream infrastructures where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers and utilizing our low cost-of-capital to invest in growing markets, including the deepwater Gulf of Mexico, the Marcellus Shale, the western United States, and areas of increasing natural gas demand.

Williams Partners' interstate transmission and related 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 near-term impact on revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

Overview of 2010

Significant events during 2010 include the following:

Echo Springs Plant Expansion

New capacity from our expansion of the Echo Springs facility began service in the fourth quarter of 2010. The addition of the fourth cryogenic processing train added approximately 350 MMcf/d of processing capacity and 30 Mbbls/d of NGL production capacity, nearly doubling Echo Spring's capacities in both cases. Approximately 70 MMcf/d of production from Exploration & Production in the Piceance basin is currently being processed at the Echo Springs facility for a volumetric-based fee. While a slow-down in Wamsutter area drilling has resulted in some unused capacity, we are exploring ways to bring more natural gas to this facility in the coming year.

Marcellus Shale Gathering Asset Acquisition

In the fourth quarter of 2010 we acquired a gathering business in Pennsylvania's Marcellus Shale in the Appalachian basin for $150 million. The business includes 75 miles of gathering pipelines and two compressor stations which currently gathers approximately 235 MMcf/d. We have agreed to a new long-term dedicated gathering agreement with the seller for its production in the northeast Pennsylvania area of the Marcellus Shale. The acquired system will connect into the Transco pipeline through our Springville gathering pipeline, currently under construction in the Appalachian basin.

Piceance Acquisition

During the fourth quarter of 2010, we completed the purchase of certain gathering and processing assets in the Piceance basin from Exploration & Production as discussed in Note 1 of Notes to Consolidated Financial Statements. In conjunction with this purchase, we entered into a gathering and processing agreement with Exploration & Production, such that future gathering and processing revenues will be at a higher, market-based rate. Prior periods reflect gathering and processing revenues at an internal cost of service rate.

Perdido Norte

Our Perdido Norte project, in the western deepwater of the Gulf of Mexico, began start-up of operations late in the first quarter of 2010. The project includes a 200 MMcf/d expansion of our onshore Markham gas processing facility and a total of 179 miles of deepwater oil and gas lines that expand the scale of our existing infrastructure. Shortly after an initial startup, during the second quarter, production was suspended by the operator of the deepwater producing platforms to address facility issues and the third quarter was impacted by further delays. While these issues have been resolved and both oil and gas production is currently flowing, production has been impacted in part by the drilling moratorium and the producer's technical issues, and has not increased as quickly as expected. We anticipate volumes to increase significantly, however, during 2011.

Impact of Gulf Oil Spill

Our transportation and processing assets in the Gulf of Mexico were not physically impacted by the Deepwater Horizon oil spill. Operations are normal at all facilities, and we did not experience any operational or logistical issues that hindered the safety of our employees or facilities. The drilling moratorium, in force from May to October, in the Gulf of Mexico impacted the financial performance of our operations through production delays which reduced natural gas and oil growth volumes in 2010. Protracted delays in permitting and drilling could continue to impact our future growth volumes. While we continue to carefully monitor the events and business environment in the Gulf of Mexico for potential negative impacts, we also continue to pursue major expansion and growth opportunities in that region.

Overland Pass Pipeline

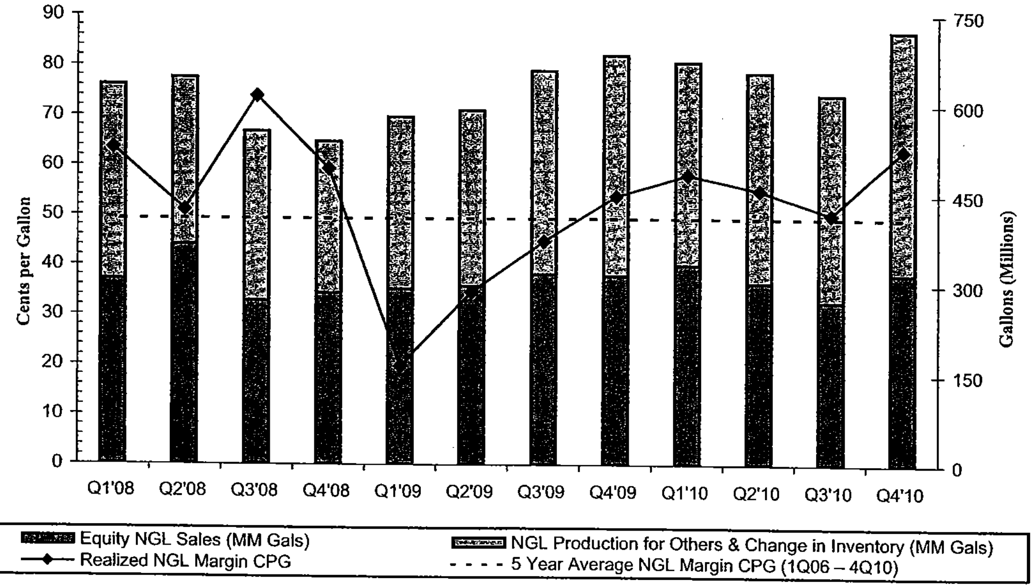
In September 2010, we completed the $424 million acquisition of an additional 49 percent ownership interest in OPPL, which increased our ownership interest to 50 percent. In 2006, we entered into an agreement to develop new pipeline capacity for transporting NGLs from production areas in the Rocky Mountain area to central Kansas. Our partner reimbursed us for the development costs we had incurred for the proposed pipeline and acquired 99 percent of the pipeline. We retained a 1 percent interest and the option to increase our ownership to 50 percent within two years of the pipeline becoming operational in November of 2008. As long as we retain a 50 percent ownership interest in OPPL, we have the right to become operator. We have notified our partner of our intent to operate and are currently working on an early 2011 transition. Work is also under way to determine optimal expansions to serve producers in the OPPL corridor. OPPL includes a 760-mile NGL pipeline from Opal, Wyoming, to the Mid-Continent NGL market center in Conway, Kansas, along with 150- and 125-mile extensions into the Piceance and Denver-Joules basins in Colorado, respectively. Our equity NGL volumes from our two Wyoming plants and our Willow Creek facility in Colorado are dedicated for transport on OPPL under a long-term shipping agreement.

Volatile commodity prices

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

NGL margins are defined as NGL revenues less any applicable BTU replacement cost, plant fuel, and third-party transportation and fractionation. Per-unit NGL margins are calculated based on sales of our own equity volumes at the processing plants.

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



Williams Pipeline Partners L.P.

During the third quarter, WPZ consummated its merger with WMZ. As a result, WMZ is wholly owned by WPZ and is no longer publicly traded.

Mobile Bay South project

In May 2010, a compression facility in Alabama allowing natural gas pipeline transportation service to various southbound delivery points was placed into service. The cost of the project was $32 million and increased capacity by 254 thousand dekatherms per day (Mdt/d).

Sundance Trail project

In November 2009, approval was received from the FERC to construct approximately 16 miles of 30-inch pipeline between existing compressor stations in Wyoming. The project also includes an upgrade to the existing compressor station. The total estimated cost of the project is approximately $50 million. The project was placed in service in November 2010 with an increase in capacity of 150 Mdt/d.

Outlook for 2011

The following factors could impact our business in 2011.

Commodity price changes

- We expect our average per-unit NGL margins in 2011 to be higher than our rolling five-year average per-unit NGL margins. NGL price changes have historically tracked somewhat with changes in the price of crude oil, although NGL, crude and natural gas prices are highly volatile and difficult to predict. NGL margins are highly dependent upon continued demand within the global economy. However, NGL products are currently the preferred feedstock for ethylene and propylene production, which has been shifting away from the more expensive crude-based feedstocks. Bolstered by abundant long-term domestic natural gas supplies, we expect to benefit from these dynamics in the broader global petrochemical markets.

Gathering, processing, and NGL sales volumes

- The growth of natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities.
- We anticipate growth in our onshore businesses' gas gathering and processing volumes as our infrastructure grows to support drilling activities in the Piceance and Appalachian basins. However, we anticipate no change or slight declines in basins in the Rocky Mountain and Four Corners areas due to reduced drilling activity. Due to the high proportion of fee-based processing agreements in the Piceance basin, we anticipate only a slight increase in NGL equity sales volumes.
- In our Gulf Coast businesses, we expect higher gas gathering, processing and crude transportation volumes as our Perdido Norte pipelines move into a full year of operation and other in-process drilling is completed. However, permitting and production delays related to the drilling moratorium which was in force from May to October, 2010 continue to hamper growth. While we expect an overall increase in processed gas volumes in 2011, NGL equity volumes are expected to be lower as we anticipate a major contract to change from keep-whole to fee-based processing.

Expansion projects

We have planned capital and investment expenditures of $1,090 million to $1,370 million in 2011 including expenditures related to our newly acquired gathering system in the Marcellus Shale as well as our Laurel Mountain Midstream, LLC (Laurel Mountain) equity investment. We also plan to pursue major expansion and growth opportunities in the Gulf of Mexico, as well as in the Piceance basin in conjunction with both Exploration & Production's and third-party drilling programs. The ongoing major expansion projects include:

85 North

An expansion of our existing natural gas transmission system from Alabama to various delivery points as far north as North Carolina. The cost of the project is estimated to be approximately $236 million. Phase I service was placed into service in July 2010 and increased capacity by 90 Mdt/d. Phase II service is anticipated to begin in May 2011 and will increase capacity by 219 Mdt/d.

Mobile Bay South II

Additional compression facilities and modifications to existing facilities in Alabama allowing natural gas transportation service to various southbound delivery points. In July 2010, we received approval from the U.S. Federal Energy Regulatory Commission. Construction began in October 2010 and is estimated to cost $35 million. The estimated project in-service date is May 2011 and will increase capacity by 380 Mdt/d.

Mid-South

In October 2010, we filed an application with the FERC to upgrade compressor facilities and expand our existing natural gas transmission system from Alabama to markets as far north as North Carolina. The cost of the project is estimated to be $219 million. The project is expected to be phased into service in September 2012 and June 2013, with an increase in capacity of 225 Mdt/d.

Mid-Atlantic Connector

In November 2010, we filed an application with the FERC to expand our existing natural gas transmission system from North Carolina to markets as far downstream as Maryland. The cost of the project is estimated to be $55 million and will increase capacity by 142 Mdt/d. We plan to place the project into service in November 2012.

Marcellus Shale

In the Appalachian basin, $150 million was added to our planned expansion capital to fund the 2011 construction phase of additional gathering assets, including compression and dehydration. In conjunction with a long-term agreement with a significant producer, we will construct and operate a 33-mile natural gas gathering pipeline in the Marcellus Shale region which will connect our recently acquired gathering assets in Pennsylvania's Marcellus Shale into the Transco pipeline. In order to pursue future opportunities, the project has been increased from a 20-inch diameter to a 24-inch diameter pipeline. Construction on the pipeline is expected to begin in the first quarter of 2011 and be completed during 2011.

Laurel Mountain

Capital to be invested within our Laurel Mountain Midstream, LLC (Laurel Mountain) equity investment to enable the rapid expansion of our gathering system including the initial stages of projects that are planned to provide approximately 1.5 Bcf/d of gathering capacity and 1,400 miles of gathering lines, including 400 new miles of 6-inch to 24-inch diameter pipeline. Construction has begun on our Shamrock compressor station with an initial capacity of 60 MMcf/d, expandable to 350 MMcf/d, which will likely be the largest central delivery point out of the Laurel Mountain system.

We have several other proposed projects to meet customer demands in addition to the various in-progress expansion projects previously discussed. Subject to regulatory approvals, construction of some of these projects could begin in 2011.

Year-Over-Year Operating Results

	Year Ended December 31,		
	2010	2009*	2008*
		(Millions)	
Segment revenues	$5,715	$4,602	$5,847
Segment profit	$1,574	$1,317	$1,425

* Recast as discussed in Note 1 of Notes to Consolidated Financial Statements

2010 vs. 2009

The increase in *segment revenues* includes:

- A $699 million increase in marketing revenues primarily due to higher average NGL and crude prices. These changes are more than offset by similar changes in marketing purchases.
- A $330 million increase in revenues associated with the production of NGLs reflecting an increase of $335 million associated with a 41 percent increase in average NGL per-unit sales prices.
- A $56 million increase in fee revenues primarily due to higher gathering revenue in the Piceance basin as a result of permitted increases in the cost-of-service gathering rate in 2010.

The increase in *segment costs and expenses* of $884 million includes:

- A $721 million increase in marketing purchases primarily due to higher average NGL and crude prices. These changes are substantially offset by similar changes in marketing revenues.
- A $107 million increase in costs associated with the production of NGLs reflecting an increase of $101 million associated with a 30 percent increase in average natural gas prices.
- A $19 million increase in operating costs including $12 million higher depreciation primarily due to the new Perdido Norte pipelines and a full year of depreciation on our Willow Creek facility which was placed into service in the latter part of 2009.
- A $14 million unfavorable change related to the disposal of assets reflecting the absence of a $40 million gain on the sale of our Cameron Meadows processing plant in 2009, partially offset by smaller gains in 2010. Gains recognized in 2010 include involuntary conversion gains due to insurance recoveries in excess of the carrying value of our Gulf assets which were damaged by Hurricane Ike in 2008 and our

Ignacio plant, which was damaged by a fire in 2007, as well as gains associated with sales of certain assets in Colorado's Piceance basin.

The increase in William Partners' *segment profit* includes:

- $223 million of higher NGL production margins reflecting higher NGL prices, partially offset by increased production costs associated with higher natural gas prices. NGL equity volumes were slightly higher due primarily to new production at Willow Creek, partially offset by the absence of favorable customer contractual changes and decreasing inventory levels in 2009.

- $28 million increase in equity earnings, including a $10 million increase from Discovery primarily due to higher processing margins and new volumes from the Tahiti pipeline lateral expansion completed in 2009. In addition, equity earnings from Aux Sable Liquid Products LP (Aux Sable) are $10 million higher primarily due to higher processing margins, and equity earnings from our increased investment in OPPL were $5 million.

- A $56 million increase in fee revenues as previously discussed.

- A $22 million decrease in margins related to the marketing of NGLs and crude primarily due to lower favorable changes in pricing while product was in transit in 2010 as compared to 2009.

- A $19 million increase in operating costs as previously discussed.

- A $14 million unfavorable change related to the disposal of assets as previously discussed.

2009 vs. 2008

The decrease in segment revenues includes:

- A $716 million decrease in revenues associated with the production of NGLs primarily due to lower average NGL prices.

- A $513 million decrease in marketing revenues primarily due to lower average NGL and crude prices, partially offset by higher NGL volumes.

- A $53 million decrease in revenues from lower transportation imbalance settlements in 2009 compared to 2008 (*offset in costs and operating expenses*).

- A $65 million increase in fee revenues primarily due to higher volumes resulting from connecting new supplies in the deepwater Gulf of Mexico in the latter part of 2008 and new fees for processing the Exploration & Production segment's natural gas production at Willow Creek.

- A $17 million increase in transportation revenues associated with expansion projects placed into service in 2009.

The decrease in *segment costs and expenses* of $1,132 million includes:

- A $643 million decrease in marketing purchases primarily due to lower average NGL and crude prices, including the absence of a $9 million charge in 2008 to write down the value of NGL inventories, partially offset by higher NGL volumes.

- A $435 million decrease in costs associated with the production of NGLs primarily due to lower average natural gas prices.

- A $53 million decrease in costs associated with lower transportation imbalance settlements in 2009 compared to 2008 (*offset in segment revenues*).

- A $40 million gain on the 2009 sale of our Cameron Meadows processing plant.

- The absence of $17 million of charges in 2008 related to an impairment, asset abandonments, and asset retirement obligations.

The decrease in William Partners' segment profit includes:

- $281 million of lower NGL production margins reflecting a decrease in energy commodity prices in 2009 compared to 2008.
- $124 million in higher margins related to the marketing of NGLs primarily due to favorable changes in pricing while product was in transit during 2009 as compared to significant unfavorable changes in pricing while product was in transit in 2008 and the absence of a $9 million charge in 2008 to write down the value of NGL inventories.
- A $40 million gain in 2009 on the sale of our Cameron Meadows processing plant, partially offset by the absence of a $5 million involuntary conversion gain in 2008 related to our Cameron Meadows plant.

Exploration & Production

Exploration & Production includes the natural gas development, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States, natural gas development activities in the northeastern portion of the United States, oil and natural gas interests in South America, and more recently, oil development activities in the northern United States. The gas management activities include procuring fuel and shrink gas for our midstream businesses and providing marketing services to third parties, such as producers. Additionally, gas management activities include the managing of various natural gas related contracts such as transportation, storage and related hedges.

Overview of 2010

Domestic production revenues for 2010 were higher than 2009 primarily due to higher realized average prices on our natural gas production, partially offset by lower production volumes. *Segment profit (loss)* for 2010 includes approximately $1.7 billion in impairments of natural gas properties and goodwill (see further discussion below), while 2009 included expense of $32 million associated with contractual penalties from the early termination of drilling rig contracts. Highlights of the comparative periods, primarily related to our production activities, include:

	Years Ended December 31,		
	2010	2009	% Change
Average daily domestic production (MMcfe)	1,132	1,182	−4%
Average daily total production (MMcfe)	1,185	1,236	−4%
Domestic production realized average price ($/Mcfe)(1)	$ 5.23	$ 4.85	+8%
Capital expenditures and acquisitions($ millions)	$ 2,823	$1,291	+119%
Domestic production revenues ($ millions)	$ 2,160	$2,093	+3%
Segment revenues ($ millions)	$ 4,042	$3,684	+10%
Segment profit (loss) ($ millions)	$(1,343)	$ 391	NM

(1) Realized average prices include market prices, net of fuel and shrink and hedge gains and losses. The realized hedge gain per Mcfe was $0.81 and $1.43 for 2010 and 2009, respectively.

During the second quarter of 2010, we entered into an agreement to acquire additional leasehold acreage positions and a 5 percent overriding royalty interest associated with these acreage positions. These acquisitions nearly double our acreage holdings in the Marcellus Shale and closed in July for $599 million, including closing adjustments. During 2010, we also spent a total of $164 million to acquire additional unproved leasehold acreage in the Marcellus Shale.

During the fourth quarter of 2010, we acquired a company that holds a major acreage position (approximately 85,800 net acres, most of which is undeveloped) in North Dakota's Bakken Shale oil play (Williston basin) that will diversify our interests into light, sweet crude oil production. The purchase price was approximately $949 million, including closing adjustments.

During the fourth quarter of 2010, we completed the sale of certain gathering and processing assets in the Piceance basin to WPZ for consideration of $702 million in cash and approximately 1.8 million common units. See

Note 1 in Notes to Consolidated Financial Statements. In conjunction with this sale, we entered into a gathering and processing agreement with WPZ. Gathering and processing costs prior to the sale reflect an internal cost-of-service rate. Subsequent to the closing date of the sale, gathering and processing costs will be at a higher, market-based rate.

As a result of significant declines in forward natural gas prices during third quarter 2010, we performed an interim assessment of our capitalized costs related to property and goodwill. As a result of these assessments, we recorded a $503 million impairment charge related to the capitalized costs of our Barnett Shale properties and a $175 million impairment charge related to capitalized costs of acquired unproved reserves in the Piceance Highlands, which were acquired in 2008. Additionally, we fully impaired our goodwill in the amount of $1 billion. These impairments were based on our assessment of estimated future discounted cash flows and other information. See Notes 4 and 14 of Notes to Consolidated Financial Statements for a further discussion of the impairments.

Outlook for 2011

We have the following expectations for 2011:

- Natural gas prices to remain at levels similar to 2010.
- Increase capital expenditures in 2011 over levels (before acquisitions) in 2010 to develop positions that were acquired in the Appalachian and Williston basins in 2010.
- Continuation of our development drilling program in the Appalachian, Piceance, Fort Worth, Powder River, and San Juan basins. Our total capital expenditures for 2011 are projected to be between $1.15 billion and $1.75 billion. We expect to maintain three to five drilling rigs in our newly acquired Williston basin properties with related capital expenditures expected to be between $200 million and $300 million.
- Annual average daily domestic production expected to increase approximately 9 percent over 2010.

Risks to achieving our expectations include unfavorable energy commodity price movements which are impacted by numerous factors, including weather conditions, domestic natural gas, oil and NGL production levels and demand. A significant decline in natural gas, oil and NGL prices would impact these expectations for 2011, although the impact would be somewhat mitigated by our hedging program, which hedges a significant portion of our expected production. In addition, changes in laws and regulations may impact our development drilling program.

Purchase Commitments

In connection with a gathering agreement entered into by Williams Partners with a third party in December 2010, we concurrently agreed to buy up to 200,000 MMBtu/d of natural gas priced at market prices from the same third party. Purchases under the 12-year contract are expected to begin in the third quarter of 2011. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

Commodity Price Risk Strategy

To manage the commodity price risk and volatility of owning producing gas and oil properties, we enter into derivative contracts for a portion of our future production. For 2011, we have the following contracts for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

	2011 Natural Gas	
	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Collar agreements — Rockies	45	$5.30 - $7.10
Collar agreements — San Juan	90	$5.27 - $7.06
Collar agreements — Mid-Continent	80	$5.10 - $7.00
Collar agreements — Southern California	30	$5.83 - $7.56
Collar agreements — Appalachia	30	$6.50 - $8.14
Fixed price at basin swaps	368	$5.21

	2011 Crude Oil	
	Volume (Bbls/d) (Feb-Dec)	Price ($/Bbl)
WTI Crude Oil fixed-price (entered into first-quarter 2011)	3,073	95.13

The following is a summary of our agreements and contracts for daily domestic production shown at weighted average volumes and basin-level weighted average prices for the years ended December 31, 2010, 2009 and 2008:

	2010		2009		2008	
	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Collars — Rockies	100	$6.53 - $8.94	150	$6.11 - $9.04	170	$6.16 - $9.14
Collars — San Juan	233	$5.75 - $7.82	245	$6.58 - $9.62	202	$6.35 - $8.96
Collars — Mid-Continent	105	$5.37 - $7.41	95	$7.08 - $9.73	63	$7.02 - $9.72
Collars — Southern California	45	$4.80 - $6.43	—	—	—	—
Collars — Other	28	$5.63 - $6.87	—	—	—	—
NYMEX and basis fixed-price	120	$4.40	106	$3.67	70	$3.97

Additionally, we utilize contracted pipeline capacity to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We hold a long-term obligation to deliver on a firm basis 200,000 MMbtu per day of gas to a buyer at the White River Hub (Greasewood-Meeker, CO), which is the major market hub exiting the Piceance basin. Our interests in the Piceance basin hold sufficient reserves to meet this obligation.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2010	2009*	2008*
		(Millions)	
Segment revenues:			
Domestic production revenues	$ 2,160	$2,093	$2,819
Gas management revenues	1,743	1,456	3,244
Net forward unrealized mark-to-market gains and ineffectiveness	27	18	29
Other revenues	112	117	103
Total segment revenues	$ 4,042	$3,684	$6,195
Segment profit (loss)	$(1,343)	$ 391	$1,253

* Recast as discussed in Note 1 of Notes to Consolidated Financial Statements.

2010 vs. 2009

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

- The increase in domestic production revenues reflects an increase of $156 million associated with an 8 percent increase in realized average prices including the effect of hedges, partially offset by a decrease of $89 million associated with a 4 percent decrease in production volumes sold. Production revenues in 2010 and 2009 include approximately $202 million and $93 million, respectively, related to NGLs and approximately $57 million and $38 million, respectively, related to condensate. The increase related to NGLs is primarily due to higher volumes in the Piceance basin processed by Williams Partners' Willow Creek facility, which was placed into service in the latter part of 2009;

- The increase in gas management revenues is primarily due to an increase in physical natural gas revenue as a result of a 21 percent increase in average prices on physical natural gas sales. This is primarily related to gas sales associated with our transportation and storage contracts and is offset by a similar increase in *segment costs and expenses*;

Total *segment costs and expenses* increased $2,094 million, primarily due to the following:

- $1,684 million due to 2010 impairments of property and goodwill as previously discussed. In 2009, $20 million of impairments were recorded in the Fort Worth and Arkoma basins;

- $278 million increase in gas management expenses, primarily due to an 19 percent increase in average prices on physical natural gas purchases. This increase is primarily related to the gas purchases associated with our previously discussed transportation and storage contracts and is more than offset by a similar increase in *segment revenues*. Gas management expenses in 2010 and 2009 include $48 million and $21 million, respectively, related to charges for unutilized pipeline capacity;

- $76 million higher gathering, processing, and transportation expenses primarily as a result of processing natural gas liquids at Williams Partners' Willow Creek plant, which began processing in August 2009, and higher rates charged on gathering and processing associated with certain gathering and processing assets in the Piceance basin that were sold to WPZ in the fourth quarter of 2010;

- $44 million higher severance and ad valorem taxes primarily due to higher average market prices, excluding the impact of hedges;

- $30 million higher lease and other operating expenses primarily due to increased workover and maintenance activity;

- $27 million higher depreciation, depletion, and amortization expenses primarily due to a change in prior production volumes and higher depreciable costs used in the calculation of depreciation, depletion, and amortization expenses.

Partially offsetting the increased costs is a decrease due to the absence of $32 million of expenses in 2009 related to penalties from the early release of drilling rigs as previously discussed.

The $1,734 million decrease in *segment profit (loss)* is primarily due to the impairments, partially offset by an 8 percent increase in realized average domestic prices on production and the other previously discussed changes in *segment revenues* and *segment costs and expenses.*

2009 vs. 2008

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

- $726 million, or 26 percent, decrease in domestic production revenues reflecting $946 million associated with a 31 percent decrease in realized average prices, partially offset by an increase of $220 million associated with an 8 percent increase in production volumes sold. Production revenues in 2009 and 2008 include approximately $93 million and $85 million, respectively, related to NGLs and approximately $38 million and $62 million, respectively, related to condensate. While NGL volumes were significantly higher than the prior year, NGL prices were significantly lower;

- $1,788 million, or 55 percent, decrease in gas management revenues primarily due to a decrease in physical natural gas revenue as a result of a 56 percent decrease in average prices on physical natural gas sales, slightly offset by a 2 percent increase in natural gas sales volumes. This is primarily related to gas sales associated with our transportation and storage contracts and is substantially offset by a similar decrease in *segment costs and expenses.*

The decrease in *net forward unrealized mark-to-market gains (losses) and ineffectiveness* is primarily related to the absence of a $10 million favorable impact in 2008 for the initial consideration of our own nonperformance risk in estimating the fair value of our derivative liabilities.

Total *segment costs and expenses* decreased $1,651 million, primarily due to the following:

- $1,752 million decrease in gas management expenses, primarily due to a 55 percent decrease in average prices on physical natural gas purchases, slightly offset by a 2 percent increase in natural gas purchase volumes. This decrease is primarily related to the gas purchases associated with our previously discussed transportation and storage contracts and is more than offset by a similar decrease in *segment revenues*. Gas management expenses in 2009 and 2008 include $21 million and $8 million, respectively, related to charges for unutilized pipeline capacity. Gas management expenses in 2009 and 2008 also include $7 million and $35 million, respectively, related to adjustments to the carrying value of natural gas inventories in storage;

- $166 million lower operating taxes due primarily to 56 percent lower average market prices (excluding the impact of hedges), partially offset by higher production volumes sold. The lower operating taxes include a net decrease of $39 million reflecting a $34 million charge in 2008 and $5 million of favorable revisions in 2009 relating to Wyoming severance and ad valorem tax issues;

- $143 million due to the absence of property impairments recorded in 2008 in the Arkoma basin;

- $6 million lower SG&A expenses, which include lower bad debt expense related to the partial recovery of certain receivables previously reserved for in 2008 resulting from a bankrupt counterparty.

Partially offsetting the decreased costs are increases due to the following:

- The absence of a $148 million gain recorded in 2008 associated with the sale of our Peru interests;

- $145 million higher depreciation, depletion, and amortization expense primarily due to the impact of higher capitalized drilling costs from prior years and higher production volumes compared to the prior year. Also, we recorded an additional $17 million of depreciation, depletion, and amortization in the fourth quarter of 2009 primarily due to new SEC reserves reporting rules. Our proved reserves decreased primarily due to the new SEC reserves reporting rules and the related price impact;

- $57 million higher gathering, processing and transportation expense primarily due to higher production volumes and the processing fees for natural gas liquids at Williams Partners' Willow Creek plant, which began processing in August 2009;
- $32 million of expense related to penalties from the early release of drilling rigs as previously discussed;
- $31 million higher exploratory expense in 2009, primarily related to $20 million of increased seismic costs and $12 million related to higher amortization and the write-off of lease acquisition costs. Dry hole costs for 2009 and 2008 were $11 million and $12 million, respectively. As of December 31, 2009, we have approximately $14 million of capitalized drilling costs and $24 million of undeveloped leasehold costs related to continuing exploratory activities in the Paradox basin;
- $20 million of impairment costs in the Fort Worth and Arkoma basins. We recorded a $15 million impairment in 2009 related to costs of acquired unproved reserves resulting from a 2008 acquisition in the Fort Worth basin. This impairment was based on our assessment of estimated future discounted cash flows and additional information obtained from drilling and other activities in 2009. We also recorded a $5 million impairment in the Arkoma basin in 2009 related to facilities.

The $862 million decrease in segment profit is primarily due to the 31 percent decrease in realized average domestic prices and the other previously discussed changes in segment revenues and segment costs and expenses.

Other

Other includes other business activities that are not operating segments, primarily our Canadian midstream and domestic olefins operations and a 25.5 percent interest in Gulfstream, as well as corporate operations. *Segment profit (loss)* for the year ended December 31, 2010, has improved compared to the prior year primarily due to $139 million higher NGL and olefins production margins resulting from significantly higher average per-unit margins on lower volumes and the net impact of recognizing $43 million in gains on the Accroven investment in 2010 while recording a $75 million impairment charge on that investment in 2009.

Significant events for 2010 include the following:

Sale of Accroven

Considering the deteriorating circumstances in Venezuela, in 2009 we fully impaired our $75 million investment in Accroven SRL, a Venezuelan operation. (See Note 2 of Notes to Consolidated Financial Statements.) In June of 2010, we sold our 50 percent interest in Accroven to the state-owned oil company, Petróleos de Venezuela S.A. (PDVSA) for $107 million. Of this amount, $13 million was received in cash at closing and another $30 million was received in August 2010. The remainder is due in six quarterly payments beginning October 31, 2010. The first quarterly payment of $11 million was received in January 2011 and will be recognized as income in 2011. We will continue to recognize the resulting gain as cash is received. Accroven was not part of our operations that were expropriated by the Venezuelan government in May 2009.

Completion of the butylene/butane splitter facility in Canada

The new butylene/butane splitter and hydro-treating facility was placed into service in August 2010. The butylene/butane splitter further fractionates the butylene/butane mix product produced at our Redwater fractionators near Edmonton, Alberta, into separate butylene and butane products, which receive higher values and are in greater demand. The source of the product fractionated at Redwater is our oil sands off-gas extraction facility near Ft. McMurray, Alberta.

Outlook for 2011

The following factors could impact our business in 2011.

Commodity price changes

We anticipate average per-unit margins in 2011 will be consistent with the 2010 levels. Margins in our Canadian midstream and domestic olefins business are highly dependent upon continued demand within the global economy. NGL products are currently the preferred feedstock for ethylene and propylene production which has been shifting away from the more expensive crude-based feedstocks. Bolstered by abundant long-term domestic natural gas supplies, we expect to benefit from these dynamics in the broader global petrochemical markets because of our NGL-based olefins production.

Allocation of capital to projects

We expect to spend $380 million to $480 million in 2011 on capital projects. The major expansion projects include a 12-inch diameter pipeline in Canada, which will transport recovered NGLs and olefins from our extraction plant in Ft. McMurray to our Redwater fractionation facility. The pipeline will have sufficient capacity to transport additional recovered liquids in excess of those from our current agreements. Construction has begun and we anticipate an in-service date in 2012.

Year-Over-Year Operating Results

	Year Ended December 31,		
	2010	2009	2008
		(Millions)	
Segment revenues	$1,057	$780	$1,257
Segment profit (loss)	$ 240	$ (2)	$ 142

2010 vs. 2009

Segment revenues increased primarily due to:

- $307 million higher NGL and olefins production revenues resulting from higher average per-unit prices. The new butylene/butane splitter began producing and selling both butylene and butane in August 2010 and resulted in $22 million additional sales revenues over the 2009 butylene/butane mix product sold.
- $27 million higher marketing revenues due to general increases in energy commodity prices on slightly higher volumes. The higher marketing revenues were more than offset by similar changes in marketing purchases described below.

Partially offsetting the increased revenue was a $57 million decrease from lower sales volumes primarily due to:

- 11 percent lower Gulf ethylene sales volumes, including the impact of a four-week plant maintenance outage at our Geismar plant during the fourth quarter of 2010.
- 12 percent lower propylene volumes sold primarily due to the absence of certain large 2009 propylene inventory sales and lower volumes available for processing at our Gulf propylene splitter.

Segment costs and expenses increased $150 million primarily as a result of:

- $156 million higher NGL and olefins production product costs resulting from higher average per-unit feedstock costs.
- $29 million increased marketing purchases due to general increases in energy commodity prices on slightly higher volumes. The increased marketing purchases more than offset similar changes in marketing revenues.
- $7 million higher operating and general and administrative costs in our Canadian midstream and domestic olefins operations.

Partially offsetting the increased costs are decreases due to:

- $45 million of reduced product costs resulting from the lower sales volumes described above.

- $6 million favorable customer settlement in 2010.

The favorable change in *segment profit (loss)* is primarily due to $139 million higher NGL and olefins production margins resulting from significantly higher average per-unit margins on lower volumes and the net impact of recognizing $43 million in gains on the Accroven investment in 2010 while recording a $75 million impairment charge on that investment in 2009.

2009 vs. 2008

Segment revenues decreased primarily due to:

- A $457 million decrease in NGL and olefins production revenues resulting from lower average product prices, partially offset by higher volumes.

- A $19 million decrease in marketing revenues primarily due to lower average NGL and olefin prices, partially offset by higher NGL and olefin volumes.

Segment costs and expenses decreased $413 million primarily as a result of:

- A $445 million decrease in costs in our NGL and olefins production business primarily due to lower per-unit feedstock costs, including the absence of an $11 million charge in 2008 to write-down the value of olefin inventories, partially offset by higher volumes.

- A $34 million decrease in marketing purchases primarily due to lower average NGL and olefin prices, including the absence of an $11 million charge in 2008 to write-down the value of our NGL inventories, partially offset by higher volumes.

These decreases were partially offset by:

- A $39 million unfavorable change primarily due to foreign currency exchange gains in 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations.

- The absence of $32 million of income in 2008 related to the partial settlement of our Gulf Liquids litigation (see Note 16 of Notes to Consolidated Financial Statements).

The unfavorable change in segment profit (loss) was primarily due to:

- A $75 million loss from investment related to the 2009 impairment of our investment in Accroven.

- A $39 million unfavorable change primarily due to foreign currency exchange gains in 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations.

- The absence of $32 million of income in 2008 related to the partial settlement of our Gulf Liquids litigation.

- A $12 million decrease in NGL and olefins production margins primarily due to lower average prices, partially offset by lower per-unit feedstock costs, including the absence of an $11 million charge in 2008 to write-down the value of olefin production inventories, and higher volumes in 2009 related to the impact of third-party operational issues in 2008 that reduced off-gas supplies to our plant in Canada.

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

These decreases were partially offset by $15 million higher marketing margins in our NGL and olefins production business primarily due to the absence of an $11 million charge in 2008 to write-down the value of NGL inventories.

Management's Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2010, we continued to focus upon growth through disciplined investments in our businesses. Examples of this growth included:

- Continued investment in Exploration & Production's development drilling programs, as well as acquisitions that expanded our presence in the Marcellus Shale and provided our initial entry into the Bakken Shale areas.

- Expansion of Williams Partners' interstate natural gas pipeline system to meet the demand of growth markets.

- Continued investment in Williams Partners' deepwater Gulf expansion projects, gas processing capacity in the western United States, infrastructure in the Marcellus Shale area and increased ownership in OPPL.

These investments were funded through cash flow from operations, debt and equity offerings at WPZ and cash on hand.

During 2010, the overall economic recession has impacted us. In consideration of our liquidity under these conditions, we note the following:

- As of December 31, 2010, we have approximately $800 million of cash and cash equivalents and approximately $2.7 billion of available credit capacity under our credit facilities. Our $900 million credit facility does not expire until May 2012, and WPZ's $1.75 billion credit facility does not expire until February 2013. Additionally, Exploration & Production has an unsecured credit agreement that serves to reduce our margin requirements related to our hedging activities. (See additional discussion in the following Available Liquidity section.)

- Our credit exposure to derivative counterparties is partially mitigated by master netting agreements and collateral support. (See Note 15 of Notes to Consolidated Financial Statements.)

Outlook

For 2011, we expect operating cash flows to be stronger than 2010 levels. Lower-than-expected energy commodity prices would be somewhat mitigated by certain of our cash flow streams that are substantially insulated from short-term changes in commodity prices as follows:

- Firm demand and capacity reservation transportation revenues under long-term contracts from our gas pipelines;

- Hedged natural gas sales at Exploration & Production related to a significant portion of its production;

- Fee-based revenues from certain gathering and processing services in our midstream businesses.

We believe we have, or have access to, the financial resources and liquidity necessary to meet our requirements for working capital, capital and investment expenditures, and tax and debt payments while maintaining a sufficient level of liquidity. In particular, we note the following assumptions for the year:

- We expect to maintain consolidated liquidity (which includes liquidity at WPZ) of at least $1 billion from *cash and cash equivalents* and unused revolving credit facilities;

- We expect to fund capital and investment expenditures, debt payments, dividends, and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, utilization of our revolving credit facilities, and proceeds from debt issuances and sales of equity securities as needed. Based on a range of market assumptions, we currently estimate our cash flow from operations will be between $2.5 billion and $3.3 billion in 2011;

- We expect capital and investment expenditures to total between $3.125 billion and $4.125 billion in 2011. Of this total, a significant portion of Williams Partners' expected expenditures of $1.58 billion to

$1.905 billion are considered nondiscretionary to meet legal, regulatory, and/or contractual requirements or to fund committed growth projects. Exploration & Production's expected expenditures of $1.15 billion to $1.75 billion are considered primarily discretionary. See Results of Operations — Segments, Williams Partners and Exploration & Production for discussions describing the general nature of these expenditures.

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

- Sustained reductions in energy commodity prices from the range of current expectations;
- Lower than expected distributions, including incentive distribution rights, from WPZ. WPZ's liquidity could also be impacted by a lack of adequate access to capital markets to fund its growth;
- Lower than expected levels of cash flow from operations from Exploration & Production and our other businesses.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2011. Our internal and external sources of consolidated liquidity include cash generated from our operations, cash and cash equivalents on hand, and our credit facilities. Additional sources of liquidity, if needed, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. These sources are available to us at the parent level and are expected to be available to certain of our subsidiaries, particularly equity and debt issuances from WPZ. WPZ is expected to be self-funding through its cash flows from operations, use of its credit facility, and its access to capital markets. Cash held by WPZ is available to us through distributions in accordance with the partnership agreement, which considers our level of ownership and incentive distribution rights. 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

	Expiration	December 31, 2010 WPZ	WMB (Millions)	Total
Cash and cash equivalents		$ 187	$ 608(1)	$ 795
Available capacity under our $900 million unsecured revolving and letter of credit facility(2)	May 1, 2012		900	900
Capacity available to Williams Partners L.P. under its $1.75 billion senior unsecured credit facility(2)	February 17, 2013	1,750		1,750
		$1,937	$1,508	$3,445

(1) *Cash and cash equivalents* includes $25 million of funds received from third parties as collateral. The obligation for these amounts is reported as *accrued liabilities* on the Consolidated Balance Sheet. Also included is $518 million of *cash and cash equivalents* that is being utilized by certain subsidiary and international operations. The remainder of our *cash and cash equivalents* is primarily held in government-backed instruments.

(2) At December 31, 2010, we are in compliance with the financial covenants associated with these credit facilities. See Note 11 of Notes to Consolidated Financial Statements.

In addition to the credit facilities listed above, we have issued letters of credit totaling $90 million as of December 31, 2010, under certain bilateral bank agreements.

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

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

Exploration & Production has an unsecured credit agreement with certain banks that, so long as certain conditions are met, serves to reduce our use of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. In July 2010, the agreement term was extended from December 2013 to December 2015. The impairments of goodwill, natural gas producing properties and acquired unproved reserves recorded by our Exploration & Production segment in the third quarter of 2010 (see Notes 4 and 14 of Notes to Consolidated Financial Statements) did not impact our ability to utilize Exploration & Production's credit agreement to facilitate hedging our future natural gas production.

Credit Ratings

Our ability to borrow money is impacted by our credit ratings and the credit ratings of WPZ. The current ratings are as follows:

	WMB	WPZ
Standard and Poor's(1)		
Corporate Credit Rating	BBB−	BBB−
Senior Unsecured Debt Rating	BB+	BBB−
Outlook	Positive	Positive
Moody's Investors Service(2)		
Senior Unsecured Debt Rating	Baa3	Baa3
Outlook	Stable	Stable
Fitch Ratings(3)		
Senior Unsecured Debt Rating	BBB−	BBB−
Outlook	Stable	Stable

(1) A rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" indicates that the security has significant speculative characteristics. A "BB" rating indicates that Standard & Poor's believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor's may modify its ratings with a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

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

(3) A rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" is considered speculative grade. Fitch may add a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

Credit rating agencies perform independent analyses when assigning credit ratings. No assurance can be given that the credit rating agencies will continue to assign us investment grade ratings even if we meet or exceed their current criteria for investment grade ratios. A downgrade of our credit rating might increase our future cost of borrowing and would require us to post additional collateral with third parties, negatively impacting our available liquidity. As of December 31, 2010, we estimate that a downgrade to a rating below investment grade for WMB or WPZ would require us to post up to $453 million or $53 million, respectively, in additional collateral with third parties.

Sources (Uses) of Cash

	Years Ended December 31,		
	2010	2009	2008
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 2,651	$ 2,572	$ 3,355
Financing activities	573	166	(432)
Investing activities	(4,296)	(2,310)	(3,183)
Increase (decrease) in cash and cash equivalents	$(1,072)	$ 428	$ (260)

Operating activities

Our *net cash provided by operating activities* in 2010 increased slightly from 2009 primarily due to the improvement in the energy commodity price environment during the year.

The decrease in *net cash provided by operating activities* from 2009 to 2008 was primarily due to the decrease in our operating results.

Financing activities

Significant transactions include:

2010

- $369 million received from WPZ's December 2010 equity offering used primarily to reduce revolver borrowings mentioned below and to fund a portion of WPZ's acquisition of a midstream business in Pennsylvania's Marcellus Shale in December 2010;
- $200 million received in revolver borrowings from WPZ's $1.75 billion unsecured credit facility primarily used for WPZ's general partnership purposes and to fund a portion of the cash consideration paid for WPZ's acquisition of certain gathering and processing assets in Colorado's Piceance basin in November 2010;
- $600 million received from WPZ's public offering of 4.125 percent senior unsecured notes in November 2010 primarily used to fund a portion of the cash consideration paid to Exploration & Production for WPZ's Piceance acquisition (see Note 1 of Notes to Consolidated Financial Statements);
- $430 million received in revolver borrowings from WPZ's $1.75 billion unsecured credit facility primarily used to fund our increased ownership in OPPL, a transaction that closed in September 2010;
- $437 million received from a WPZ equity offering used to reduce WPZ's revolver borrowings mentioned above;
- $3.491 billion received by WPZ in February 2010 from the issuance of $3.5 billion of senior unsecured notes related to our previously discussed restructuring (see Note 11 of Notes to Consolidated Financial Statements);
- $3 billion of senior unsecured notes retired in February 2010 and $574 million paid in associated premiums utilizing proceeds from the $3.5 billion debt issuance (see Note 11 of Notes to Consolidated Financial Statements);
- $250 million received from revolver borrowings on WPZ's $1.75 billion unsecured credit facility in February 2010 to repay a term loan;
- We paid $284 million of quarterly dividends on common stock for the year ended December 31, 2010.

2009

- We received $595 million net cash from the issuance of $600 million aggregate principal amount of 8.75 percent senior unsecured notes due 2020 to fund general corporate expenses and capital expenditures. (See Note 11 of Notes to Consolidated Financial Statements.);
- We paid $256 million of quarterly dividends on common stock for the year ended December 31, 2009.

2008

- We received $362 million from the completion of the WMZ initial public offering;
- We paid $474 million for the repurchase of our common stock. (See Note 12 of Notes to Consolidated Financial Statements.);
- WPZ received $75 million net proceeds from debt transactions;
- We paid $250 million of quarterly dividends on common stock for the year ended December 31, 2008.

Investing activities

Significant transactions include:

2010

- Capital expenditures totaled $2.8 billion in 2010. Included is approximately $599 million, including closing adjustments, related to Exploration & Production's acquisition in the Marcellus Shale in July 2010 (see Results of Operations — Segments, Exploration & Production);
- We paid approximately $949 million, including closing adjustments, for Exploration & Production's December 2010 business purchase, consisting primarily of oil and gas properties in the Bakken Shale (see Results of Operations — Segments, Exploration & Production);
- We contributed $488 million to our investments, including a $424 million cash payment for WPZ's September 2010 acquisition of an increased interest in OPPL (see Results of Operations — Segments, Williams Partners);
- We paid $150 million for WPZ's December 2010 business purchase, consisting primarily of certain midstream assets in the Marcellus Shale.

2009

- Capital expenditures totaled $2.4 billion, more than half of which related to Exploration & Production. Included was a $253 million payment by Exploration & Production for the purchase of additional properties in the Piceance basin. (See Results of Operations — Segments, Exploration & Production.);
- We received $148 million as a distribution from Gulfstream following its debt offering;
- We contributed $142 million to our investments, including $106 million related to our Laurel Mountain equity investment and $20 million related to our Gulfstream equity investment.

2008

- Capital expenditures totaled $3.4 billion and were primarily related to Exploration & Production's drilling activity. This total includes Exploration & Production's acquisitions of certain interests in the Piceance and Fort Worth basins;
- We received $148 million of cash from Exploration & Production's sale of a contractual right to a production payment;

- We contributed $111 million to our investments, including $90 million related to our Gulfstream equity investment.

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

We have various other guarantees and commitments which are disclosed in Notes 9, 11, 15 and 16 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 at December 31, 2010, including obligations related to discontinued operations.

	2011	2012-2013	2014-2015	Thereafter	Total
			(Millions)		
Long-term debt, including current portion:					
Principal	$ 507	$ 352	$ 750	$ 7,532	$ 9,141
Interest	580	1,071	1,017	5,046	7,714
Capital leases	1	3	—	—	4
Operating leases	89	84	59	182	414
Purchase obligations(1)	1,068	1,446	1,233	2,674	6,421
Other long-term liabilities, including current portion:					
Physical and financial derivatives(2)(3)	489	1,058	870	3,634	6,051
Other(4)(5)	165	—	—	—	165
Total	$2,899	$4,014	$3,929	$19,068	$29,910

(1) Includes $2.3 billion of natural gas purchase obligations at market prices at our Exploration & Production segment. The purchased natural gas can be sold at market prices.

(2) Includes $5.4 billion of physical natural gas derivatives related to purchases at market prices in our Exploration & Production segment. The natural gas expected to be purchased under these contracts can be sold at market prices. The obligations for physical and financial derivatives are based on market information as of December 31, 2010, and assumes contracts remain outstanding for their full contractual duration. Because market information changes daily and has the potential to be volatile, significant changes to the values in this category may occur.

(3) Expected offsetting cash inflows of $2.1 billion at December 31, 2010, resulting from product sales or net positive settlements, are not reflected in these amounts. In addition, product sales may require additional purchase obligations to fulfill sales obligations that are not reflected in these amounts.

(4) Does not include estimated contributions to our pension and other postretirement benefit plans. We made contributions to our pension and other postretirement benefit plans of $76 million in 2010 and $77 million in 2009. In 2011, we expect to contribute approximately $83 million to these plans (see Note 7 of Notes to Consolidated Financial Statements). During 2010, we contributed $60 million to our tax-qualified pension plans which was greater than the minimum required contributions. We expect to contribute approximately $60 million to these pension plans again in 2011, which is expected to be greater than the minimum required contributions. In the past, we have contributed amounts in excess of the minimum required contribution. These excess amounts can be used to offset future minimum contribution requirements. In the future, we may elect to use some of these excess amounts to satisfy the minimum contribution requirement in order to maintain cash contributions at the current level. Additionally, estimated future minimum funding requirements may vary significantly from historical requirements if actual results differ significantly from estimated results for

assumptions such as returns on plan assets, interest rates, retirement rates, mortality, and other significant assumptions or by changes to current legislation and regulations.

(5) Includes $165 million reflecting our estimate of an income tax settlement to be paid in 2011. We have not included other income tax liabilities in the table above. See Note 5 of Notes to Consolidated Financial Statements for a discussion of income taxes, including our unrecognized tax benefits.

Effects of Inflation

Our operations have benefited from relatively low inflation rates. Approximately 35 percent of our gross property, plant, and equipment is comprised of our interstate gas pipelines. These assets are 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 remainder of our business, operating costs are influenced to a greater extent by both competition for specialized services and specific price changes in crude oil and natural gas and related commodities than by changes in general inflation. Crude oil, natural gas, and NGL prices are particularly sensitive to the Organization of the Petroleum Exporting Countries (OPEC) production levels and/or the market perceptions concerning the supply and demand balance in the near future, as well as general economic conditions. However, our exposure to certain of these price changes is reduced through the use of hedging instruments and the fee-based nature of certain of our services.

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 16 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 $49 million, all of which are included in *accrued liabilities* and *other liabilities and deferred income* on the Consolidated Balance Sheet at December 31, 2010. We will seek recovery of approximately $12 million of these accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2010, we paid approximately $8 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $11 million in 2011 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, 2010, 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 also subject to the Federal Clean Air Act (Act) and to the Federal Clean Air Act Amendments of 1990 (1990 Amendments), which added significantly to the existing requirements established by the Act. Pursuant to requirements of the 1990 Amendments and EPA rules designed to mitigate the migration of ground-level ozone (NOx), we are planning installation of air pollution controls on existing sources at certain facilities in order to reduce NOx emissions. For many of these facilities, we are developing more cost effective and innovative compressor engine control designs.

In March 2008, the EPA promulgated a new, lower National Ambient Air Quality Standard (NAAQS) for ground-level ozone. Within two years, the EPA was expected to designate new eight-hour ozone non-attainment areas. However, in September 2009, the EPA announced it would reconsider the 2008 NAAQS for ground level ozone to ensure that the standards were clearly grounded in science and were protective of both public health and the environment. As a result, the EPA delayed designation of new eight-hour ozone non-attainment areas under the 2008 standards until the reconsideration is complete. In January 2010, the EPA proposed to further reduce the ground-level ozone NAAQS from the March 2008 levels. The EPA currently anticipates finalization of the new ground-level ozone standard in the third quarter of 2011. Designation of new eight-hour ozone non-attainment areas are expected to result in additional federal and state regulatory actions that will likely impact our operations and increase the cost of additions to *property, plant and equipment-net* on the Consolidated Balance Sheet. We are unable at this time to estimate the cost of additions that may be required to meet this new regulation.

Additionally, in August 2010, the EPA promulgated National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations that will impact our operations. The emission control additions required to comply with the NESHAP regulations are estimated to include costs in the range of $31 million to $39 million through 2013, the compliance date.

Furthermore, the EPA promulgated the Greenhouse Gas (GHG) Mandatory Reporting Rule on October 30, 2009, which requires facilities that emit 25,000 metric tons or more carbon dioxide (CO_2) equivalent per year from stationary fossil fuel combustion sources to report GHG emissions to the EPA annually beginning March 31, 2011 for calendar year 2010. On November 30, 2010, the EPA issued additional regulations that expand the scope of the Mandatory Reporting Rule to include fugitive and vented greenhouse gas emissions effective January 1, 2011. Facilities that emit 25,000 metric tons or more CO_2 equivalent per year from stationary fossil-fuel combustion and fugitive/vented sources combined will be required to report GHG combustion and fugitive/vented emissions to the EPA annually beginning March 31, 2012, for calendar year 2011. Compliance with this reporting obligation is estimated to cost a total of $10 million to $14 million over the next four to five years.

In February 2010, the EPA promulgated a final rule establishing a new one-hour nitrogen dioxide (NO_2) NAAQS. The effective date of the new NO_2 standard was April 12, 2010. This new standard is subject to numerous challenges in the federal court. We are unable at this time to estimate the cost of additions that may be required to meet this new regulation.

Our interstate natural gas pipelines consider prudently incurred environmental assessment and remediation costs and the costs associated with compliance with environmental standards to be recoverable through rates.

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

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. The majority of our debt portfolio is comprised of fixed rate debt in order to mitigate the impact of fluctuations in interest rates. Any borrowings under our credit facilities could be at a variable interest rate and could expose us to the risk of increasing interest rates. The maturity of our long-term debt portfolio is partially influenced by the expected lives of our operating assets.

The tables below provide information by maturity date about our interest rate risk-sensitive instruments as of December 31, 2010 and 2009. 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 market rates and the prices of similar securities with similar terms and credit ratings.

	2011	2012	2013	2014	2015	Thereafter(1)	Total	Fair Value December 31, 2010
					(Millions)			
Long-term debt, including current portion(2):								
Fixed rate	$507	$352	$—	$—	$750	$7,495	$9,104	$9,990
Interest rate	6.4%	6.4%	6.3%	6.3%	6.4%	6.9%		

	2010	2011	2012	2013	2014	Thereafter(1)	Total	Fair Value December 31, 2009
					(Millions)			
Long-term debt, including current portion(2):								
Fixed rate	$ 15	$936	$953	$—	$—	$6,119	$8,023	$8,905
Interest rate	7.7%	7.7%	7.7%	7.7%	7.7%	8.0%		
Variable rate	$—	$ —	$250	$—	$—	$ —	$ 250	$ 237
Interest rate(3)								

(1) Includes unamortized discount and premium.

(2) Excludes capital leases.

(3) The interest rate at December 31, 2009 was LIBOR plus 1 percent.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, NGL and crude, as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. (See Note 15 of Notes to Consolidated Financial Statements.)

We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios. Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolios in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Contracts designated as normal purchases or sales and nonderivative energy contracts have been excluded from our estimation of value at risk.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net asset of $2 million at December 31, 2010. The value at risk for contracts held for trading purposes was less than $1 million at December 31, 2010 and December 31, 2009.

Nontrading

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

Segment	Commodity Price Risk Exposure
Williams Partners	• Natural gas purchases • NGL sales
Exploration & Production	• Natural gas purchases and sales
Other	• NGL purchases

The fair value of our nontrading derivatives was a net asset of $282 million at December 31, 2010.

The value at risk for derivative contracts held for nontrading purposes was $24 million at December 31, 2010, and $34 million at December 31, 2009. During the year ended December 31, 2010, our value at risk for these contracts ranged from a high of $33 million to a low of $21 million. The decrease in value at risk primarily reflects the realization of certain derivative positions and the market price impact, partially offset by new derivative contracts.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges. Of the total fair value of nontrading derivatives, cash flow hedges had a net asset value of $266 million as of December 31, 2010. Though these contracts are included in our value-at-risk calculation, any changes in the fair value of the effective portion of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Trading Policy

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

Foreign Currency Risk

Net assets of our consolidated foreign operations, whose functional currency is the local currency, are located primarily in Canada and approximate 8 percent and 6 percent of our net assets at December 31, 2010 and 2009, respectively. These foreign operations do not have significant transactions or financial instruments denominated in currencies other than their functional currency. However, these investments do have the potential to impact our financial position, due to fluctuations in these local currencies arising from the process of translating 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 would have changed *stockholders' equity* by approximately $117 million at December 31, 2010.

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

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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). Our internal controls over financial reporting are 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 including the possibility of human error and the circumvention or overriding of controls. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2010, based on the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework.* Based on our assessment, we concluded that, as of December 31, 2010, our internal control over financial reporting was effective.

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

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

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

We have audited The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Williams Companies, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, The Williams Companies, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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, 2010 and 2009, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2010 of The Williams Companies, Inc. and our report dated February 24, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 24, 2011

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, 2010 and 2009, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2010. 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. The 2010 financial statements of Gulfstream Natural Gas System, L.L.C. ("Gulfstream") (a limited liability corporation in which the Company has a 50% interest), have been audited by other auditors whose report has been furnished to us, and our opinion on the 2010 consolidated financial statements, insofar as it relates to the amounts included for Gulfstream, is based solely on the report of the other auditors. In the consolidated financial statements, the Company's investment in Gulfstream is stated at $378 million at December 31, 2010 and the Company's equity earnings in the net income of Gulfstream is stated at $66 million for the year then ended.

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 and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of The Williams Companies, Inc. at December 31, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, 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 discussed in Note 9 to the consolidated financial statements, beginning in the fourth quarter of 2009, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 24, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Members of Gulfstream Natural Gas System, L.L.C.
Houston, Texas

We have audited the balance sheet of Gulfstream Natural Gas System, L.L.C., (the "Company"), as of December 31, 2010, and the related statements of operations, cash flows, and members' equity and comprehensive income for the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the auditing 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Gulfstream Natural Gas System, L.L.C. as of December 31, 2010, and the results of its operations and its cash flows for the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 23, 2011

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF OPERATIONS

	Years Ended December 31,		
	2010	2009	2008
	(Millions, except per-share amounts)		
Revenues:			
Williams Partners*	$ 5,715	$ 4,602	$ 5,847
Exploration & Production*	4,042	3,684	6,195
Other	1,057	780	1,257
Intercompany eliminations*	(1,198)	(811)	(1,409)
Total revenues	9,616	8,255	11,890
Segment costs and expenses:			
Costs and operating expenses	7,185	6,081	8,776
Selling, general, and administrative expenses	498	512	504
Impairments of goodwill and long-lived assets	1,692	20	153
Other (income) expense — net	(24)	(3)	(225)
Total segment costs and expenses	9,351	6,610	9,208
General corporate expenses	221	164	149
Operating income (loss):			
Williams Partners*	1,465	1,236	1,349
Exploration & Production*	(1,363)	373	1,233
Other	163	36	100
General corporate expenses	(221)	(164)	(149)
Total operating income (loss)	44	1,481	2,533
Interest accrued	(632)	(661)	(636)
Interest capitalized	51	76	59
Investing income — net	209	46	189
Early debt retirement costs	(606)	(1)	(1)
Other income (expense) — net	(12)	2	—
Income (loss) from continuing operations before income taxes	(946)	943	2,144
Provision (benefit) for income taxes	(30)	359	677
Income (loss) from continuing operations	(916)	584	1,467
Income (loss) from discontinued operations	(6)	(223)	125
Net income (loss)	(922)	361	1,592
Less: Net income attributable to noncontrolling interests	175	76	174
Net income (loss) attributable to The Williams Companies, Inc.	$ (1,097)	$ 285	$ 1,418
Amounts attributable to The Williams Companies, Inc.:			
Income (loss) from continuing operations	$ (1,091)	$ 438	$ 1,306
Income (loss) from discontinued operations	(6)	(153)	112
Net income (loss)	$ (1,097)	$ 285	$ 1,418
Basic earnings (loss) per common share:			
Income (loss) from continuing operations	$ (1.87)	$ .75	$ 2.25
Income (loss) from discontinued operations	(.01)	(.26)	.19
Net income (loss)	$ (1.88)	$ .49	$ 2.44
Weighted-average shares (thousands)	584,552	581,674	581,342
Diluted earnings (loss) per common share:			
Income (loss) from continuing operations	$ (1.87)	$ .75	$ 2.21
Income (loss) from discontinued operations	(.01)	(.26)	.19
Net income (loss)	$ (1.88)	$ .49	$ 2.40
Weighted-average shares (thousands)	584,552	589,385	592,719

* 2009 and 2008 recast as discussed in Note 1.

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

	December 31, 2010	December 31, 2009
	(Millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 795	$ 1,867
Accounts and notes receivable (net of allowance of $15 at December 31, 2010 and $22 at December 31, 2009)	859	816
Inventories	303	222
Derivative assets	400	650
Other current assets and deferred charges	173	238
Total current assets	2,530	3,793
Investments	1,344	886
Property, plant, and equipment — net	20,272	18,644
Derivative assets	173	444
Goodwill	8	1,011
Other assets and deferred charges	645	502
Total assets	$24,972	$25,280
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 918	$ 934
Accrued liabilities	1,002	948
Derivative liabilities	146	578
Long-term debt due within one year	508	17
Total current liabilities	2,574	2,477
Long-term debt	8,600	8,259
Deferred income taxes	3,448	3,656
Derivative liabilities	143	428
Other liabilities and deferred income	1,588	1,441
Contingent liabilities and commitments (Note 16)		
Equity:		
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 620 million shares issued at December 31, 2010 and 618 million shares issued at December 31, 2009)	620	618
Capital in excess of par value	8,269	8,135
Retained earnings (deficit)	(478)	903
Accumulated other comprehensive income (loss)	(82)	(168)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders' equity	7,288	8,447
Noncontrolling interests in consolidated subsidiaries	1,331	572
Total equity	8,619	9,019
Total liabilities and equity	$24,972	$25,280

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	The Williams Companies, Inc., Stockholders							
	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss	Treasury Stock	Total Stockholders' Equity	Noncontrolling Interest	Total
	(Millions, except per-share amounts)							
Balance, December 31, 2007	$608	$6,748	$ (293)	$(121)	$ (567)	$ 6,375	$ 1,430	$7,805
Comprehensive income:								
Net income	—	—	1,418	—	—	1,418	174	1,592
Other comprehensive income:								
Net change in cash flow hedges (Note 17)	—	—	—	453	—	453	2	455
Foreign currency translation adjustments	—	—	—	(76)	—	(76)	—	(76)
Pension benefits:								
Prior service cost	—	—	—	1	—	1	—	1
Net actuarial loss	—	—	—	(337)	—	(337)	(7)	(344)
Other postretirement benefits:								
Prior service cost	—	—	—	9	—	9	—	9
Net actuarial loss	—	—	—	(9)	—	(9)	—	(9)
Total other comprehensive income						41	(5)	36
Total comprehensive income						1,459	169	1,628
Cash dividends — common stock (Note 12)	—	—	(250)	—	—	(250)	—	(250)
Sale of limited partner units of consolidated partnership	—	—	—	—	—	—	362	362
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(122)	(122)
Issuance of common stock from 5.5% debentures conversion (Note 12)	2	25	—	—	—	27	—	27
Conversion of Williams Partners L.P. subordinated units to common units (Note 12)	—	1,225	—	—	—	1,225	(1,225)	—
Purchase of treasury stock (Note 12)	—	—	—	—	(474)	(474)	—	(474)
Stock-based compensation, net of tax benefit	3	67	—	—	—	70	—	70
Other	—	9	(1)	—	—	8	—	8
Balance, December 31, 2008	613	8,074	874	(80)	(1,041)	8,440	614	9,054
Comprehensive income:								
Net income	—	—	285	—	—	285	76	361
Other comprehensive loss:								
Net change in cash flow hedges (Note 17)	—	—	—	(221)	—	(221)	—	(221)
Foreign currency translation adjustments	—	—	—	83	—	83	—	83
Pension benefits:								
Net actuarial gain	—	—	—	46	—	46	7	53
Other postretirement benefits:								
Prior service cost	—	—	—	4	—	4	—	4
Total other comprehensive loss						(88)	7	(81)
Total comprehensive income						197	83	280
Cash dividends — common stock (Note 12)	—	—	(256)	—	—	(256)	—	(256)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(129)	(129)
Issuance of common stock from 5.5% debentures conversion (Note 12)	3	25	—	—	—	28	—	28
Stock-based compensation, net of tax benefit	2	36	—	—	—	38	—	38
Other	—	—	—	—	—	—	4	4
Balance, December 31, 2009	618	8,135	903	(168)	(1,041)	8,447	572	9,019
Comprehensive income (loss):								
Net income (loss)	—	—	(1,097)	—	—	(1,097)	175	(922)
Other comprehensive income:								
Net change in cash flow hedges (Note 17)	—	—	—	92	—	92	—	92
Foreign currency translation adjustments	—	—	—	29	—	29	—	29
Pension benefits:								
Prior service cost	—	—	—	1	—	1	—	1
Net actuarial loss	—	—	—	(25)	—	(25)	—	(25)
Other postretirement benefits:								
Prior service cost	—	—	—	(3)	—	(3)	—	(3)
Net actuarial loss	—	—	—	(8)	—	(8)	—	(8)
Total other comprehensive income	—	—	—	—	—	86	—	86
Total comprehensive income (loss)	—	—	—	—	—	(1,011)	175	(836)
Cash dividends — common stock (Note 12)	—	—	(284)	—	—	(284)	—	(284)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(145)	(145)
Issuance of common stock from 5.5% debentures conversion (Note 12)	—	2	—	—	—	2	—	2
Sale of limited partner units of consolidated partnership	—	—	—	—	—	—	806	806
Stock-based compensation, net of tax benefit	2	55	—	—	—	57	—	57
Changes in Williams Partners L.P. ownership interest, net	—	77	—	—	—	77	(77)	—
Other	—	—	—	—	—	—	—	—
Balance, December 31, 2010	$620	$8,269	$ (478)	$ (82)	$(1,041)	$ 7,288	$ 1,331	$8,619

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31,		
	2010	2009	2008
		(Millions)	
OPERATING ACTIVITIES:			
Net income (loss)	$ (922)	$ 361	$ 1,592
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, depletion, and amortization	1,507	1,469	1,310
Provision (benefit) for deferred income taxes	(155)	249	611
Provision for loss on goodwill, investments, property and other assets	1,735	386	166
Gain on sale of contractual production rights	—	—	(148)
Provision for doubtful accounts and notes	(6)	48	15
Amortization of stock-based awards	48	43	31
Early debt retirement costs	606	1	1
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	(36)	52	335
Inventories	(81)	33	(48)
Margin deposits and customer margin deposits payable	(1)	4	88
Other current assets and deferred charges	43	7	(82)
Accounts payable	(14)	5	(343)
Accrued liabilities	(29)	(170)	7
Changes in current and noncurrent derivative assets and liabilities	(42)	36	(121)
Other, including changes in noncurrent assets and liabilities	(2)	48	(59)
Net cash provided by operating activities	2,651	2,572	3,355
FINANCING ACTIVITIES:			
Proceeds from long-term debt	5,129	595	674
Payments of long-term debt	(4,305)	(33)	(665)
Proceeds from sale of limited partner units of consolidated partnerships	806	—	362
Dividends paid	(284)	(256)	(250)
Purchase of treasury stock	—	—	(474)
Dividends and distributions paid to noncontrolling interests	(145)	(129)	(122)
Payments for debt issuance costs	(71)	(7)	(4)
Premiums paid on early debt retirements	(574)	—	—
Changes in restricted cash	—	40	(5)
Changes in cash overdrafts	14	(51)	—
Other — net	3	7	52
Net cash provided (used) by financing activities	573	166	(432)
INVESTING ACTIVITIES:			
Capital expenditures*	(2,788)	(2,387)	(3,394)
Purchases of investments/advances to affiliates	(488)	(142)	(111)
Purchase of businesses	(1,099)	—	—
Proceeds from sale of contractual production rights	—	—	148
Distribution from Gulfstream Natural Gas System, L.L.C.	—	148	—
Other — net	79	71	174
Net cash used by investing activities	(4,296)	(2,310)	(3,183)
Increase (decrease) in cash and cash equivalents	(1,072)	428	(260)
Cash and cash equivalents at beginning of year	1,867	1,439	1,699
Cash and cash equivalents at end of year	$ 795	$ 1,867	$ 1,439
* Increases to property, plant, and equipment	$(2,755)	$(2,314)	$(3,475)
Changes in related accounts payable and accrued liabilities	(33)	(73)	81
Capital expenditures	$(2,788)	$(2,387)	$(3,394)

See accompanying notes.

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: Williams Partners, Exploration & Production, and Other.

Williams Partners consists of our consolidated master limited partnership, Williams Partners L.P. (WPZ) and includes the gas pipeline and midstream businesses that were contributed as part of our first quarter 2010 restructuring. The contributed gas pipeline businesses include 100 percent of Transcontinental Gas Pipe Line Company, LLC (Transco), 65 percent of Northwest Pipeline GP (Northwest Pipeline), and 24.5 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream). The remaining 35 percent of Northwest Pipeline is directly owned by WPZ following the third quarter 2010 merger of WPZ and Williams Pipeline Partners L.P. (WMZ). WPZ's midstream operations are composed of significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, operations in Pennsylvania's Marcellus Shale region, and various equity investments in domestic processing and fractionation assets. WPZ's midstream assets also include substantial operations and investments in the Four Corners and Gulf Coast regions, as well as a NGLs fractionator and storage facilities near Conway, Kansas.

Exploration & Production includes the natural gas development, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States, natural gas development activities in the northeastern portion of the United States, oil and natural gas interests in South America, and more recently, oil development activities in the northern United States. The gas management activities include procuring fuel and shrink gas for our midstream businesses and providing marketing to third parties, such as producers. Additionally, gas management activities include managing various natural gas related contracts such as transportation, storage, and related hedges.

Other includes other business activities that are not operating segments, primarily our Canadian midstream and domestic olefins operations, a 25.5 percent interest in Gulfstream, as well as corporate operations.

Basis of Presentation

During fourth-quarter 2010, we contributed a business represented by certain gathering and processing assets in Colorado's Piceance basin to WPZ. The transaction has been accounted for as a combination of entities under common control whereby the assets and liabilities sold were recorded by WPZ at their historical amounts. The operations of this business and the related assets and liabilities were previously reported through our Exploration & Production segment, however they are now reported in our Williams Partners segment. Prior period segment disclosures have been adjusted for this transaction.

Master limited partnerships

At December 31, 2010, we own approximately 75 percent of the interests in WPZ, including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. At December 31, 2009, we owned approximately 24 percent of WPZ. Changes in our ownership of WPZ occurring during the past year include:

- In conjunction with our first quarter 2010 restructuring, we ultimately received 203,000,000 common units from WPZ. Following this transaction, we owned approximately 84 percent of WPZ.
- On August 31, 2010, WMZ unitholders approved the merger between WMZ and WPZ. As a result of the merger, effective September 1, 2010, WMZ unitholders, other than its general partner, received 0.7584 WPZ common units for each WMZ common unit they owned at the effective time of the merger, for a total issuance of 13,580,485 common units. Upon completing this merger, WMZ is wholly owned by WPZ and is no longer publicly traded.

- On September 28, 2010, WPZ completed an equity issuance of common units resulting in proceeds of $380 million, net of the underwriters' discount and fees.
- On October 8, 2010, WPZ sold additional common units to the underwriters upon the underwriters' exercise of their option to purchase additional common units pursuant to WPZ's common unit offering in September 2010. The offering resulted in proceeds of $57 million, net of the underwriters' discount and fees.
- On December 17, 2010, WPZ completed an equity issuance of common units resulting in proceeds of approximately $369 million, net of the underwriters' discount and fees.

These transactions resulted in changes in ownership between us and the noncontrolling interest that have been accounted for as equity transactions, resulting in an aggregate $77 million increase in capital in excess of par and a corresponding decrease in noncontrolling interest in consolidated subsidiaries.

WPZ is self funding and maintains separate lines of bank credit and cash management accounts. Cash distributions from WPZ to us, including any associated with our incentive distribution rights, occur through the normal partnership distributions from WPZ to all partners.

Discontinued operations

The accompanying consolidated financial statements and notes reflect the results of operations and financial position of certain of our Venezuela operations and other former businesses as discontinued operations. (See Note 2).

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

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of our corporate parent and our majority-owned or controlled subsidiaries and investments. We apply the equity method of accounting for investments in unconsolidated companies in which we and our subsidiaries own 20 to 50 percent of the voting interest, otherwise exercise significant influence over operating and financial policies of the company, or where majority ownership does not provide us with control due to significant participatory rights of other owners.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Significant estimates and assumptions include:

- Impairment assessments of investments, long-lived assets and goodwill;
- Litigation-related contingencies;
- Valuations of derivatives;
- Hedge accounting correlations and probability;
- Environmental remediation obligations;
- Realization of deferred income tax assets;

- Valuation of Exploration & Production's reserves;
- Asset retirement obligations;
- Pension and postretirement valuation variables.

These estimates are discussed further throughout these notes.

Regulatory accounting

Transco and Northwest Pipeline are regulated by the Federal Energy Regulatory Commission (FERC). Their rates established by the FERC are designed to recover the costs of providing the regulated services, and their competitive environment makes it probable that such rates can be charged and collected. Therefore, our management has determined that it is appropriate to account for and report regulatory assets and liabilities related to these operations consistent with the economic effect of the way in which their rates are established. Accounting for these businesses that are regulated can differ from the accounting requirements for non-regulated businesses. These differences are discussed further throughout these notes.

Cash and cash equivalents

Our *cash and cash equivalents* balance includes amounts primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government. These have maturity dates of three months or less when acquired.

Accounts receivable

Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Interest income related to past due accounts receivable is generally recognized at the time full payment is received or collectability 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. The cost of inventories is primarily determined using the average-cost method. We determine the cost of certain natural gas inventories held by Transco using the last-in, first-out (LIFO) cost method. LIFO inventory at December 31, 2010 and 2009 is $9 million and $7 million, respectively.

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. See Note 9 for depreciation rates used for major regulated gas plant facilities.

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. See Note 9 for the estimated useful lives associated with our nonregulated assets.

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

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

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

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

Measurements of AROs include, as a component of future expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties inherent in the obligations, sometimes referred to as a market-risk premium.

Goodwill

Goodwill represents the excess of cost over fair value of the assets of businesses acquired. It is evaluated at least 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.

As a result of significant declines in forward natural gas prices during the third quarter of 2010, we performed an interim impairment assessment of our goodwill. As a result of that assessment, we recorded an impairment of goodwill of approximately $1 billion. See Note 4.

Cash flows from revolving credit facilities

Proceeds and payments related to borrowings under our credit facilities are reflected in the *financing activities* of the Consolidated Statement of Cash Flows on a gross basis.

Treasury stock

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

Derivative instruments and hedging activities

We utilize derivatives to manage our commodity price risk. These instruments consist primarily of futures contracts, swap agreements, option contracts, and forward contracts involving short- and long-term purchases and sales of a physical energy commodity.

We report the fair value of derivatives, except for those for which the normal purchases and normal sales exception has been elected, on the Consolidated Balance Sheet in *derivative assets* and *derivative liabilities* as either current or noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual trades. We report these amounts on a gross basis. Additionally, we report cash collateral receivables and payables with our counterparties on a gross basis.

The accounting for the changes in fair value of a commodity derivative can be summarized as follows:

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

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

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

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

For commodity derivatives that are not designated in a hedging relationship, and for which we have not elected the normal purchases and normal sales exception, we report changes in fair value currently in *revenues* or *costs and operating expenses* dependent upon the underlying hedge transaction.

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 hedges and for which we have not elected the normal purchases and normal sales exception;
- The ineffective portion of unrealized gains and losses on derivatives that are designated as cash flow hedges;
- Realized gains and losses on all derivatives that settle financially other than natural gas derivatives for NGL processing activities;
- 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, as well as natural gas derivatives for NGL processing activities and which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we considered 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.

Revenues

Revenues from our gas pipeline businesses are primarily from services pursuant to long-term firm transportation and storage agreements. These agreements provide for a reservation charge based on the volume of contracted capacity and a commodity charge based on the volume of gas delivered, both at rates specified in our FERC tariffs. We recognize revenues for reservation charges ratably over the contract period regardless of the volume of natural gas that is transported or stored. Revenues for commodity charges, from both firm and interruptible transportation services, and storage injection and withdrawal services, are recognized when natural gas is delivered at the agreed upon delivery point or when natural gas is injected or withdrawn from the storage facility.

In the course of providing transportation services to customers, we may receive different quantities of gas from shippers than the quantities delivered on behalf of those shippers. The resulting imbalances are primarily settled through the purchase and sale of gas with our customers under terms provided for in our FERC tariffs. Revenue is recognized from the sale of gas upon settlement of the transportation and exchange imbalances.

As a result of the ratemaking process, certain revenues collected by us may be subject to refunds upon the issuance of final orders by the FERC in pending rate proceedings. We record estimates of rate refund liabilities considering our and other third-party regulatory proceedings, advice of counsel and other risks.

Revenues from our midstream operations include those derived from natural gas gathering and processing services and are performed under volumetric-based fee contracts, keep-whole agreements and percent-of-liquids arrangements. Revenues under volumetric-based fee contracts are recorded when services have been performed. Under keep-whole and percent-of-liquids processing contracts, we retain the rights to all or a portion of the NGLs extracted from the producers' natural gas stream and recognize revenues when the extracted NGLs are sold and delivered.

Oil gathering and transportation revenues and offshore production handling fees of our midstream operations are recognized when the services have been performed. Certain offshore production handling contracts contain fixed payment terms that result in the deferral of revenues until such services have been performed.

We market NGLs that we purchase from our producer customers. Revenues from marketing NGLs are recognized when the products have been sold and delivered.

Storage revenues under prepaid contracted storage capacity contracts are recognized evenly over the life of the contract as services are provided.

Revenues for sales of natural gas are recognized when the product is sold and delivered. 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.

We have NGLs and olefins extraction operations where we retain certain products extracted from the producers' off-gas stream and we recognize revenues when the extracted products are sold and delivered to our purchasers. We also produce olefins from purchased feed-stock, and we recognize revenues when the olefins are sold and 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. Except for proved and unproved properties discussed below, 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 and 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, 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.

Proved properties, including developed and undeveloped, are assessed for impairment using estimated future undiscounted cash flows on a field basis. If the undiscounted cash flows are less than the carrying value of the assets, then a subsequent analysis to estimate fair value is performed using discounted cash flows. Estimating future cash flows involves the use of complex judgments such as estimation of the 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.

Unproved properties include lease acquisition costs and costs of acquired unproved reserves. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the average holding period. The estimate of what could be nonproductive is based on our historical experience or other information, including current drilling plans and existing geological data. A majority of the costs of acquired unproved reserves are associated with areas to which proved developed producing reserves are also attributed. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing development program. Ultimate recovery of potentially recoverable reserves in areas with established production generally has greater probability than in areas with limited or no prior drilling activity. Costs of acquired unproved reserves are assessed annually, or as conditions warrant, for impairment using estimated future discounted cash flows on a field basis and considering our future drilling plans. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties.

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 charge.

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.

Capitalization of interest

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

Employee stock-based awards

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. 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 can be subject to accelerated vesting if certain future stock prices or specific financial performance targets are achieved. Stock options generally expire ten years after the grant.

Restricted stock units are generally valued at market value on the grant date and generally vest over three years. Restricted stock unit compensation cost, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

Income taxes

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

Earnings (loss) per common share

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

Foreign currency translation

Certain of our foreign subsidiaries use the Canadian dollar as their functional currency. Assets and liabilities of such foreign subsidiaries are translated at the spot rate in effect at the applicable reporting date, and the combined statements of operations 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 AOCI.

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

Note 2. Discontinued Operations

Summarized Results of Discontinued Operations

	Years Ended December 31,		
	2010	2009	2008
		(Millions)	
Revenues	$—	$ —	$ 172
Income (loss) from discontinued operations before (impairments) and gain on sale, gain on deconsolidation and income taxes	$(2)	$ (87)	$ 241
(Impairments) and gain on sale	—	(211)	8
Gain on deconsolidation	—	9	—
(Provision) benefit for income taxes	(4)	66	(124)
Income (loss) from discontinued operations	$(6)	$(223)	$ 125
Income (loss) from discontinued operations:			
Attributable to noncontrolling interests	$—	$ (70)	$ 13
Attributable to The Williams Companies, Inc.	$(6)	$(153)	$ 112

The decrease in *revenues* reflects the cessation of revenue recognition of our discontinued Venezuela operations in 2009.

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

Income (loss) from discontinued operations before (impairments) and gain on sale, gain on deconsolidation, and income taxes for 2008 includes:

- $140 million of gains related to the favorable resolution of matters involving pipeline transportation rates associated with our former Alaska operations;
- $77 million of income related to our discontinued Venezuela operations;
- $54 million of income related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank;
- An $11 million charge associated with an oil purchase contract related to our former Alaska refinery;
- A $10 million charge associated with a settlement primarily related to the sale of NGL pipeline systems in 2002.

(Impairments) and gain on sale for 2009 reflects an impairment of our Venezuela property, plant, and equipment. (See Note 14.)

(Impairments) and gain on sale for 2008 includes the final proceeds from the 2007 sale of our former power business.

Gain on deconsolidation reflects the gain recognized when we deconsolidated the entities that owned and operated our Venezuela gas compression facilities prior to their expropriation by the Venezuelan government in 2009.

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

Note 3. Investing Activities

Investing Income

	Years Ended December 31,		
	2010	2009	2008
		(Millions)	
Equity earnings*	$163	$136	$137
Income (loss) from investments*	43	(75)	1
Impairment of cost-based investments	—	(22)	(4)
Interest income and other	3	7	55
Total investing income	$209	$ 46	$189

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

Income (loss) from investments in 2009 reflects a $75 million impairment charge related to an other-than-temporary loss in value associated with our Venezuelan investment in Accroven SRL (Accroven). Accroven owns and operates gas processing facilities and a NGL fractionation plant for the exclusive benefit of Petróleos de Venezuela S.A. (PDVSA). The deteriorating circumstances in the first quarter of 2009 for our Venezuelan operations caused us to review our investment in Accroven. We utilized a probability-weighted discounted cash flow analysis, which included an after-tax discount rate of 20 percent to reflect the risk associated with operating in Venezuela. Accroven was not part of the operations that were expropriated by the Venezuelan government in May 2009.

In June 2010, we sold our 50 percent interest in Accroven to the state-owned oil company, PDVSA for $107 million. Of this amount, $13 million was received in cash at closing and another $30 million was received in August 2010. The remainder is due in six quarterly payments beginning October 31, 2010. The first quarterly payment of $11 million was received in January 2011 and will be recognized as income in 2011. We will continue to recognize the resulting gain as cash is received. Accroven was not part of our operations that were expropriated by the Venezuelan government in May 2009.

Impairment of cost-based investments in 2009 includes an $11 million impairment related to our 4 percent interest in a Venezuelan corporation that owns and operates oil and gas activities. This investment resulted from our previous 10 percent direct working interest in a concession that was converted to a reduced interest in a mixed company at the direction of the Venezuelan government in 2006. Considering our evaluation of the deteriorating financial condition of this corporation, we recorded an other-than-temporary decline in value of our remaining investment balance.

The unfavorable change in *interest income and other* in 2009 is primarily due to lower average interest rates which continued in 2010.

Investments

	December 31, 2010	December 31, 2009
	(Millions)	
Equity method:		
Overland Pass Pipeline Company LLC — 50%	$ 429	$ —
Gulfstream — 50%(1)	378	383
Discovery Producer Services LLC — 60%(2)	181	189
Laurel Mountain Midstream, LLC — 51%(2)	170	133
Petrolera Entre Lomas S.A. — 40.8%	81	81
Other	103	98
	1,342	884
Cost method	2	2
	$1,344	$886

(1) As of December 31, 2010, 24.5 percent interest is held within Williams Partners, with the remaining 25.5 percent held within Other.

(2) We account for these investments under the equity method due to the significant participatory rights of our partners such that we do not control the investments.

Differences between the carrying value of our equity investments and the underlying equity in the net assets of the investees are primarily related to impairments we previously recognized. These differences are amortized over the expected remaining life of the investees' underlying assets.

In September 2010, we purchased an additional 49 percent ownership interest in Overland Pass Pipeline Company LLC (OPPL) for $424 million. In addition, we invested $43 million and $133 million in Laurel Mountain Midstream, LLC in 2010 and 2009, respectively.

Dividends and distributions, including those presented below, received from companies accounted for by the equity method were $193 million, $291 million, and $167 million in 2010, 2009, and 2008, respectively. These transactions reduced the carrying value of our investments. These dividends and distributions primarily included:

	Years Ended December 31, 2010	2009	2008
		(Millions)	
Gulfstream	$81	$223	$58
Discovery Producer Services LLC	44	32	56
Aux Sable Liquid Products LP	28	15	28

In 2009, we received a $148 million distribution from Gulfstream following its debt offering.

Summarized Financial Position and Results of Operations of Equity Method Investments (Unaudited)

	December 31, 2010	December 31, 2009
	(Millions)	
Current assets	$ 321	$ 383
Noncurrent assets	4,421	3,723
Current liabilities	229	266
Noncurrent liabilities	1,409	1,511

	Years Ended December 31, 2010	2009	2008
		(Millions)	
Gross revenue	$1,362	$1,115	$1,246
Operating income	699	516	521
Net income	508	396	405

Note 4. Asset Sales, Impairments and Other Accruals

The following table presents significant gains or losses reflected in *impairments of goodwill and long-lived assets* and *other (income) expense — net* within *segment costs and expenses*:

	Years Ended December 31, 2010	2009	2008
		(Millions)	
Williams Partners			
Involuntary conversion gains	$ (18)	$ (4)	$ (17)
Gains on sales of certain assets	(12)	(40)	(10)
Accrual of regulatory liability related to overcollection of certain employee expenses	10	—	—
Impairments of certain gathering and transportation assets	9	—	6
Exploration & Production			
Gain on sale of contractual right to an international production payment	—	—	(148)
Impairment of goodwill	1,003	—	—
Impairments of producing properties and acquired unproved reserves	678	20	143
Penalties from early release of drilling rigs	—	32	—
Other			
Gulf Liquids litigation contingency accrual reversal (see Note 16)	—	—	(32)

Other (income) expense — net within *segment costs and expenses* also includes net foreign currency exchange gains of $38 million in 2008, which primarily relates to the remeasurement of current assets held in U.S. dollars within our Canadian operations in the Other segment.

Impairments of goodwill and certain Exploration & Production properties

As a result of significant declines in forward natural gas prices during the third quarter of 2010, we performed an interim impairment assessment of our capitalized costs related to goodwill and domestic properties at Exploration & Production. As a result of these assessments, Exploration & Production recorded an impairment of goodwill, as noted above, and impairments of capitalized costs of certain natural gas producing properties in the

Barnett Shale of $503 million and capitalized costs of certain acquired unproved reserves in the Piceance Highlands acquired in 2008 of $175 million.

Based on a comparison of the estimated fair value to the carrying value, Exploration & Production recorded a $15 million impairment in 2009 related to costs of acquired unproved reserves resulting from a 2008 acquisition in the Fort Worth basin. Additionally, Exploration & Production recorded impairment charges of $5 million and $143 million in 2009 and 2008, respectively, related to properties in the Arkoma basin.

Our impairment analyses included assessments of undiscounted (except for the unproved reserves) and discounted future cash flows, which considered information obtained from drilling, other activities, and year-end natural gas reserve quantities. See Note 14 for a further discussion of the impairments.

Additional Items

We completed a strategic restructuring transaction in 2010 that involved significant debt issuances, retirements and amendments (see Note 11). We incurred significant costs related to these transactions, as follows:

- $606 million of early debt retirement costs consisting primarily of cash premiums;
- $45 million of other transaction costs reflected in *general corporate expenses,* of which $7 million is attributable to noncontrolling interests;
- $4 million of accelerated amortization of debt costs related to the amendments of credit facilities, reflected in *other income (expense) — net* below *operating income (loss).*

Exploration & Production recorded a $19 million unfavorable adjustment to depletion expense in 2010 related to a correction of prior years' production volumes used in the calculation of depletion expense, which is reflected in *costs and operating expenses.*

Exploration & Production recorded $16 million of exploratory dry hole costs in 2010, which is included within *costs and operating expenses.*

Exploration & Production recorded a $34 million accrual for Wyoming severance taxes in 2008, which is reflected in *costs and operating expenses.*

Note 5. Provision (Benefit) for Income Taxes

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

	Years Ended December 31,		
	2010	2009	2008
		(Millions)	
Current:			
Federal	$ 81	$ 10	$179
State	2	12	24
Foreign	40	21	8
	123	43	211
Deferred:			
Federal	(61)	271	466
State	(104)	42	(11)
Foreign	12	3	11
	(153)	316	466
Total provision (benefit)	$ (30)	$359	$677

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:

	Years Ended December 31,		
	2010	2009	2008
		(Millions)	
Provision (benefit) at statutory rate	$(331)	$330	$750
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	(70)	35	8
Foreign operations — net	(17)	25	(16)
Impact of nontaxable noncontrolling interests	(58)	(49)	(54)
Goodwill impairment	351	—	—
Taxes on undistributed earnings of certain foreign operations	66	—	—
Reduction of tax benefits on Medicare Part D federal subsidy	11	—	—
Other — net	18	18	(11)
Provision (benefit) for income taxes	$ (30)	$359	$677

State income taxes (net of federal benefit) were reduced by $65 million in 2010 and $46 million in 2008 due to reductions in our estimate of the effective deferred state rate, including state income tax carryovers, reflective of a change in the mix of jurisdictional attribution of taxable income.

Income (loss) from continuing operations before income taxes includes $173 million of foreign income, $36 million of foreign loss, and $139 million of foreign income in 2010, 2009, and 2008, respectively.

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 filing positions, we apply the two step process of recognition and measurement. In association with this liability, we record an estimate of related interest and tax exposure as a component of our tax provision. The impact of this accrual is included within *other-net* in our reconciliation of the tax provision to the federal statutory rate.

Significant components of *deferred tax liabilities* and *deferred tax assets* are as follows:

	December 31, 2010	December 31, 2009
	(Millions)	
Deferred tax liabilities:		
Property, plant, and equipment	$1,784	$3,658
Derivatives — net	111	66
Investments	2,125	491
Other	100	108
Total deferred tax liabilities	4,120	4,323
Deferred tax assets:		
Accrued liabilities	369	557
Minimum tax credits	120	62
State loss and credit carryovers	278	289
Other	70	58
Total deferred tax assets	837	966
Less valuation allowance	249	289
Net deferred tax assets	588	677
Overall net deferred tax liabilities	$3,532	$3,646

The valuation allowance at December 31, 2010 and 2009 serves to reduce the recognized tax assets associated with state loss and credit carryovers to an amount that will more likely than not be realized. These amounts are presented in the table above before any federal benefit.

As a result of the plan approved by our Board of Directors to pursue separation of the company into two standalone publicly traded corporations (see Note 19), we provided $66 million of deferred taxes in 2010 on undistributed earnings of certain foreign operations that we no longer consider permanently reinvested. As of December 31, 2010, we still consider $277 million of undistributed earnings of other consolidated foreign subsidiaries to be permanently reinvested and have not provided deferred income taxes on that amount.

Cash payments for income taxes (net of refunds and including discontinued operations) were $40 million, $14 million, and $155 million in 2010, 2009, and 2008, respectively.

As of December 31, 2010, we had approximately $91 million of unrecognized tax benefits. If recognized, approximately $74 million, net of federal tax expense, would be recorded as a reduction of income tax expense. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2010	2009
	(Millions)	
Balance at beginning of period	$ 89	$79
Additions based on tax positions related to the current year	11	17
Additions for tax positions for prior years	3	4
Reductions for tax positions of prior years	(12)	(7)
Settlement with taxing authorities	—	(4)
Balance at end of period	$ 91	$89

We recognize related interest and penalties as a component of income tax expense. Total interest and penalties recognized as part of income tax expense were $11 million, $17 million, and $2 million for 2010, 2009, and 2008, respectively. Approximately $104 million and $93 million of interest and penalties primarily relating to uncertain tax positions have been accrued as of December 31, 2010 and 2009, respectively.

As of December 31, 2010, the Internal Revenue Service (IRS) examination of our consolidated U.S. income tax return for 2008 is in process. During the first quarter of 2011, we finalized a settlement for 1997 through 2007 on certain contested matters with the IRS Appeals Division which we anticipate will result in a net reduction to our 2011 provision for income taxes of approximately $90 million to $100 million. This reduction is primarily driven by a deferred tax asset created as a result of our settlement. We anticipate making approximately $160 million to $170 million of cash payments to the IRS and various states related to this settlement in 2011. During the first quarter of 2011, we expect this settlement to reduce the balance of our unrecognized tax benefits by approximately $40 million. The statute of limitations for most states expires one year after expiration of the IRS statute.

Generally, tax returns for our Venezuelan, Argentine and Canadian entities are open to audit from 2003 through 2010. Certain Canadian entities are currently under examination. We believe there is a high degree of probability of an adjustment related to an international matter that could result in a decrease of approximately $17 million in our unrecognized tax benefits during the next twelve months.

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

	Years Ended December 31,		
	2010	2009	2008
	(Dollars in millions, except per-share amounts; shares in thousands)		
Income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders for basic and diluted earnings (loss) per common share(1)	$ (1,091)	$ 438	$ 1,306
Basic weighted-average shares(2)	584,552	581,674	581,342
Effect of dilutive securities:			
Nonvested restricted stock units	—	2,216	1,334
Stock options	—	2,065	3,439
Convertible debentures(2)	—	3,430	6,604
Diluted weighted-average shares	584,552	589,385	592,719
Earnings (loss) per common share from continuing operations:			
Basic	$ (1.87)	$ .75	$ 2.25
Diluted	$ (1.87)	$ .75	$ 2.21

(1) The years of 2009 and 2008 include $1.2 million and $2.4 million, respectively, of interest expense, net of tax, associated with our convertible debentures. (See Note 12.) These amounts have been added back to *income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders* to calculate diluted earnings per common share.

(2) During 2009, we issued shares of our common stock in exchange for a portion of our convertible debentures. (See Note 12.)

For 2010, 3.2 million weighted-average nonvested restricted stock units and 3.0 million weighted-average stock options have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive due to our loss from continuing operations attributable to The Williams Companies, Inc.

Additionally, for 2010, 2.2 million weighted-average shares related to the assumed conversion of our convertible debentures, as well as the related interest, net of tax, have been excluded from the computation of diluted earnings per common share. Inclusion of these shares would have an antidilutive effect on the diluted earnings per common share. We estimate that if 2010 *income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders* was $219 million of income, then these shares would become dilutive.

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

	2010	2009	2008
Options excluded (millions)	2.4	3.7	6.4
Weighted-average exercise price of options excluded	$32.41	$30.21	$26.41
Exercise price range of options excluded	$22.68 - $40.51	$20.28 - $42.29	$16.40 - $42.29
Fourth quarter weighted-average market price	$22.47	$19.81	$16.37

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 elect, to the extent they are eligible for the various options, to receive annuity payments, a lump sum payment, or a combination of a lump sum and annuity payments. In addition to our pension plans, we currently provide subsidized retiree medical and life insurance benefits (other postretirement benefits) to certain eligible participants. Generally, employees hired after December 31, 1991, are not eligible for the subsidized retiree medical benefits, except for participants that were employees or retirees of Transco Energy Company on December 31, 1995, and other miscellaneous defined participant groups. Certain of these other postretirement benefit plans, particularly the subsidized retiree medical benefit plans, provide for retiree contributions and contain other cost-sharing features such as deductibles, co-payments, and co-insurance. The accounting for these plans anticipates future cost-sharing that is consistent with our expressed intent to increase the retiree contribution level generally in line with health care cost increases.

Benefit Obligations

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years indicated. The annual measurement date for our plans is December 31.

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$1,118	$1,035	$ 259	$ 273
Service cost	35	32	2	2
Interest cost	64	62	15	16
Plan participants' contributions	—	—	6	5
Benefits paid	(58)	(59)	(24)	(24)
Medicare Part D subsidy	—	—	2	2
Plan amendment	—	—	(1)	(18)
Actuarial loss	108	48	30	3
Benefit obligation at end of year	1,267	1,118	289	259
Change in plan assets:				
Fair value of plan assets at beginning of year	860	705	148	126
Actual return on plan assets	108	153	17	25
Employer contributions	61	61	15	16
Plan participants' contributions	—	—	6	5
Benefits paid	(58)	(59)	(24)	(24)
Fair value of plan assets at end of year	971	860	162	148
Funded status — underfunded	$ (296)	$ (258)	$(127)	$(111)
Accumulated benefit obligation	$1,224	$1,075		

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

	December 31,	
	2010	2009
	(Millions)	
Underfunded pension plans:		
Current liabilities	$ 7	$ 1
Noncurrent liabilities	289	257
Underfunded other postretirement benefit plans:		
Current liabilities	8	8
Noncurrent liabilities	119	103

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

The pension plans' benefit obligation *actuarial loss* of $108 million in 2010 and $48 million in 2009 is primarily due to the impact of decreases in the discount rates utilized to calculate the benefit obligation. The 2010 benefit obligation *actuarial loss* of $30 million for our other postretirement benefit plans is primarily due to the impact of decreases in the discount rates utilized to calculate the benefit obligation and changes to medical claims experience. The impact of the provisions of the federal healthcare reform legislation has been included in the December 31, 2010 other postretirement benefit plans' obligation and is not significant. The other postretirement benefits *plan amendment* of $18 million in 2009 is due to an increase in the retirees' cost-sharing percentage within our subsidized retiree medical benefit plans.

At December 31, 2010 and 2009, all of our pension plans had a projected benefit obligation and accumulated benefit obligation in excess of plan assets.

The determination of *net periodic benefit expense* allows for the delayed recognition of gains and losses caused by differences between actual and assumed outcomes for items such as estimated return on plan assets, or caused by changes in assumptions for items such as discount rates or estimated future compensation levels. The *net actuarial loss* presented in the following table and recorded in *accumulated other comprehensive loss* and *net regulatory assets* represents the cumulative net deferred loss from these types of differences or changes which have not yet been recognized in the Consolidated Statement of Income. A portion of the *net actuarial loss* is amortized over the participants' average remaining future years of service, which is approximately 13 years for our pension plans and approximately 11 years for our other postretirement benefit plans.

Pre-tax amounts not yet recognized in *net periodic benefit expense* at December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
	(Millions)			
Amounts included in accumulated other comprehensive loss:				
Prior service (cost) credit	$ (3)	$ (4)	$ 10	$ 15
Net actuarial loss	(657)	(621)	(20)	(9)
Amounts included in net regulatory assets associated with our FERC-regulated gas pipelines:				
Prior service credit	N/A	N/A	$ 20	$ 28
Net actuarial loss	N/A	N/A	(48)	(40)

In addition to the net regulatory assets included in the previous table, differences in the amount of actuarially determined *net periodic benefit expense* for our other postretirement benefit plans and the other postretirement benefit costs recovered in rates for our FERC-regulated gas pipelines are deferred as a regulatory asset or liability. We have *net regulatory liabilities* of $23 million at December 31, 2010 and $15 million at December 31, 2009 related to these deferrals. These amounts will be reflected in future rates based on the gas pipelines' rate structures.

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

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

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
	(Millions)					
Components of net periodic benefits expense:						
Service cost	$ 35	$ 32	$ 23	$ 2	$ 2	$ 2
Interest cost	64	62	60	15	16	18
Expected return on plan assets	(71)	(61)	(79)	(9)	(9)	(13)
Amortization of prior service cost (credit)	1	1	1	(14)	(11)	—
Amortization of net actuarial loss	35	43	13	3	3	—
Amortization of regulatory asset	—	1	—	1	5	5
Net periodic benefit expense	$ 64	$ 78	$ 18	$ (2)	$ 6	$ 12
Other changes in plan assets and benefit obligations recognized in other comprehensive income (loss):						
Net actuarial (gain) loss	$ 71	$(44)	$565	$ 12	$ 1	$ 15
Prior service credit	—	—	—	—	(7)	(16)
Amortization of prior service (cost) credit	(1)	(1)	(1)	5	4	(1)
Amortization of net actuarial loss	(35)	(43)	(13)	(1)	—	—
Other changes in plan assets and benefit obligations recognized in other comprehensive income (loss)	35	(88)	551	16	(2)	(2)
Total recognized in net periodic benefit expense and other comprehensive income (loss)	$ 99	$(10)	$569	$ 14	$ 4	$ 10

Other changes in plan assets and benefit obligations for our other postretirement benefit plans associated with our FERC-regulated gas pipelines are recognized in *net regulatory assets* at December 31, 2010, and include a *net actuarial loss* of $10 million, *prior service credit* of $1 million, *amortization of prior service credit* of $9 million, and *amortization of net actuarial loss* of $2 million. At December 31, 2009, amounts recognized in *net regulatory assets* included a *net actuarial gain* of $14 million, *prior service credit* of $11 million, *amortization of prior service credit* of $7 million, and *amortization of net actuarial loss* of $3 million. At December 31, 2008, amounts recognized in *net regulatory assets* included a *net actuarial loss* of $83 million, *prior service credit* of $22 million, and *amortization of prior service credit* of $1 million.

Pre-tax amounts expected to be amortized in *net periodic benefit expense* in 2011 are as follows:

	Pension Benefits	Other Postretirement Benefits
	(Millions)	
Amounts included in accumulated other comprehensive loss:		
Prior service cost (credit)	$ 1	$(4)
Net actuarial loss	37	1
Amounts included in net regulatory assets associated with our FERC-regulated gas pipelines:		
Prior service credit	N/A	$(7)
Net actuarial loss	N/A	3

Key Assumptions

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

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
Discount rate	5.20%	5.78%	5.35%	5.80%
Rate of compensation increase	5.00	5.00	N/A	N/A

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

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
Discount rate	5.78%	6.08%	6.41%	5.80%	6.00%	6.40%
Expected long-term rate of return on plan assets	7.50	7.75	7.75	6.51	7.00	7.00
Rate of compensation increase	5.00	5.00	5.00	N/A	N/A	N/A

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

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

The expected return on plan assets component of *net periodic benefit expense* is calculated using the market-related value of plan assets. For assets held in our pension plans, the market-related value of plan assets is equal to the fair value of plan assets adjusted to reflect amortization of gains or losses associated with the difference between the expected return on plan assets and the actual return on plan assets over a five-year period. Additionally, the market-related value of plan assets may be no more than 110 percent or less than 90 percent of the fair value of plan assets at the beginning of the year. The market-related value of plan assets for our other postretirement benefit plans is equal to the unadjusted fair value of plan assets at the beginning of the year.

The mortality assumptions used to determine the obligations for our pension and other postretirement benefit plans are the best estimate of expected mortality rates for the participants in these plans. The selected mortality tables are among the most recent tables available and mortality improvements are projected to the measurement date.

The assumed health care cost trend rate for 2011 is 7.0 percent, increases slightly in 2012 and 2013, and then decreases to 5.0 percent by 2021. 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	$ 2	$ (2)
Effect on other postretirement benefit obligation	39	(32)

Plan Assets

The investment policy for our pension and other postretirement benefit plans provides for an investment strategy in accordance with ERISA, which governs the investment of the assets in a diversified portfolio. The plans follow a policy of diversifying the investments across various asset classes and investment managers. Additionally, the investment returns on approximately 40 percent of the other postretirement benefit plan assets are subject to income tax; therefore, certain investments are managed in a tax efficient manner.

During 2010, the pension plans' target asset allocation ranges were adjusted resulting in a slightly larger allocation to fixed income securities. The updated pension plans' target asset allocation range at December 31, 2010 was 54 percent to 66 percent equity securities, which includes commingled investment funds, and 36 percent to 44 percent fixed income securities and cash management funds. Within equity securities, the target range for U.S. equity securities is 37 percent to 45 percent and international equity securities is 17 percent to 21 percent. The asset allocation continues to be weighted toward equity securities since the obligations of the pension and other postretirement benefit plans are long-term in nature and historically equity securities have outperformed other asset classes over long periods of time. The rebalancing to the higher fixed income securities asset allocation is expected to occur during 2011.

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 in the pension plans except where these securities may be owned in a commingled investment fund in which the plans' trusts invest. No more than 5 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 the direct holding of options or futures require approval and, historically, have not been used; however, these instruments may be used in commingled investment funds. Additionally, real estate equity and natural resource property investments are generally restricted.

Fixed income securities are restricted to high-quality, marketable securities that may include, but are not necessarily limited to, U.S. Treasury securities, U.S. government guaranteed and nonguaranteed mortgage-backed securities, government and municipal bonds, and investment grade corporate securities. The overall rating of the fixed income security assets is generally required to be at least "A," according to the Moody's or Standard & Poor's rating systems. No more than 5 percent of the total portfolio may be invested in the fixed income securities of any one issuer with the exception of bond index funds and U.S. government guaranteed and agency securities.

During 2010, nine active investment managers and one passive investment manager managed substantially all of the pension plans' funds and five active investment managers managed the other postretirement benefit plans' funds. Each of the managers had responsibility for managing a specific portion of these assets and each investment manager was responsible for 2 percent to 17 percent of the assets.

The pension and other postretirement benefit plans' assets are held primarily in equity securities, including commingled investment funds invested in equity securities, and fixed income securities. Within the plans' investment securities, there are no significant concentrations of risk because of the diversity of the types of investments, diversity of the various industries, and the diversity of the fund managers and investment strategies. Generally, the investments held in the plans are publicly traded, therefore, minimizing liquidity risk in the portfolio.

The pension and other postretirement benefit plans participate in securities lending programs under which securities are loaned to selected securities brokerage firms. The title of the securities is transferred to the borrower, but the plans are entitled to all distributions made by the issuer of the securities during the term of the loan and retain the right to redeem the securities on short notice. All loans require collateralization by U.S. government securities, cash, or letters of credit that equal at least 102 percent of the fair value of the loaned securities plus accrued interest. There are limitations on the aggregate fair value of securities that may be loaned to any one broker and to all brokers as a group. The collateral is invested in repurchase agreements, asset-backed securities, bank notes, corporate floating rate notes, and certificates of deposit. At December 31, 2010, the fair values of the loaned securities are $116 million for the pension plans and $17 million for the other postretirement benefit plans and are included in the following tables. At December 31, 2010, the fair values of securities held as collateral, and the obligation to return the collateral, are $120 million for the pension plans and $17 million for the other postretirement benefit plans and are not included in the following tables. At December 31, 2009, the fair values of the loaned securities are $63 million for the pension plans and $9 million for the other postretirement benefit plans and are included in the following tables. At December 31, 2009, the fair values of securities held as collateral, and the obligation to return the collateral, are $66 million for the pension plans and $9 million for the other postretirement benefit plans and are not included in the following tables. The pension and other postretirement benefit plans are exiting the securities lending programs under a plan designed to be orderly and minimize potential losses. The exit from the securities lending programs is expected to be completed during 2011 and no significant losses are expected to be realized.

The fair values (see Note 14) of our pension plan assets at December 31, 2010 and 2009, by asset class are as follows:

	2010			
	Level 1	Level 2	Level 3	Total
		(Millions)		
Pension assets:				
Cash management fund(1)	$ 30	$ —	$—	$ 30
Equity securities:				
U.S. large cap	192	—	—	192
U.S. small cap	137	—	—	137
International developed markets large cap growth	4	68	—	72
Emerging markets growth	4	12	—	16
Commingled investment funds:				
U.S. large cap(2)	—	168	—	168
Emerging markets value(3)	—	35	—	35
International developed markets large cap value(4)	—	80	—	80
Fixed income securities(5):				
U.S. Treasury securities	17	3	—	20
Mortgage-backed securities	—	64	—	64
Corporate bonds	—	150	—	150
Insurance company investment contracts and other	—	7	—	7
Total assets at fair value at December 31, 2010	$384	$587	$—	$971

	2009			
	Level 1	Level 2 (Millions)	Level 3	Total
Pension assets:				
Cash management fund(1)	$ 23	$ —	$—	$ 23
Equity securities:				
U.S. large cap	244	—	—	244
U.S. small cap	103	—	—	103
International developed markets large cap growth	2	58	—	60
Emerging markets growth	10	9	—	19
Commingled investment funds:				
U.S. large cap(2)	—	84	—	84
Emerging markets value(3)	—	29	—	29
International developed markets large cap value(4)	—	74	—	74
Fixed income securities(5):				
U.S. Treasury securities	11	3	—	14
Mortgage-backed securities	—	53	—	53
Corporate bonds	—	149	—	149
Insurance company investment contracts and other	—	8	—	8
Total assets at fair value at December 31, 2009	$393	$467	$—	$860

The fair values of our other postretirement benefits plan assets at December 31, 2010 and 2009, by asset class are as follows:

	2010			
	Level 1	Level 2 (Millions)	Level 3	Total
Other postretirement benefit assets:				
Cash management funds(1)	$15	$—	$—	$ 15
Equity securities:				
U.S. large cap	44	—	—	44
U.S. small cap	24	—	—	24
International developed markets large cap growth	1	14	—	15
Emerging markets growth	1	2	—	3
Commingled investment funds:				
U.S. large cap(2)	—	17	—	17
Emerging markets value(3)	—	3	—	3
International developed markets large cap value(4)	—	8	—	8
Fixed income securities(6):				
U.S. Treasury securities	2	—	—	2
Government and municipal bonds	—	10	—	10
Mortgage-backed securities	—	6	—	6
Corporate bonds	—	15	—	15
Total assets at fair value at December 31, 2010	$87	$75	$—	$162

	2009			
	Level 1	Level 2	Level 3	Total
		(Millions)		
Other postretirement benefit assets:				
Cash management funds(1)	$15	$—	$—	$ 15
Equity securities:				
U.S. large cap	49	—	—	49
U.S. small cap	19	—	—	19
International developed markets large cap growth	—	13	—	13
Emerging markets growth	2	2	—	4
Commingled investment funds:				
U.S. large cap(2)	—	8	—	8
Emerging markets value(3)	—	3	—	3
International developed markets large cap value(4)	—	7	—	7
Fixed income securities(6):				
U.S. Treasury securities	1	—	—	1
Government and municipal bonds	—	8	—	8
Mortgage-backed securities	—	6	—	6
Corporate bonds	—	15	—	15
Total assets at fair value at December 31, 2009	$86	$62	$—	$148

(1) These funds invest in high credit-quality, short-term corporate, and government money market debt securities that have remaining maturities of approximately one year or less, and are deemed to have minimal credit risk.

(2) This fund invests primarily in equity securities comprising the Standard & Poor's 500 Index. The investment objective of the fund is to match the return of the Standard & Poor's 500 Index. During 2009, certain restrictions were put into place that limited the amount that could be withdrawn. As of December 31, 2009, 37 percent was eligible for withdrawal. Effective August 2010, the withdrawal restrictions were terminated by the fund. The fund manager retains the right to restrict withdrawals from the fund as not to disadvantage other investors in the fund.

(3) This fund invests in equity securities of international emerging markets for the purpose of capital appreciation. The fund invests primarily in common stocks of the financial, telecommunications, information technology, consumer goods, energy, industrial, materials, and utilities sectors, as well as forward foreign currency exchange contracts. The plans' trustee is required to notify the fund manager ten days prior to a withdrawal from the fund. The fund manager retains the right to restrict withdrawals from the fund as not to disadvantage other investors in the fund.

(4) This fund invests in a diversified portfolio of international equity securities for the purpose of capital appreciation. The fund invests primarily in common stocks in the consumer goods, materials, financial, energy, information technology, telecommunications, industrial, utilities, and health care sectors, as well as forward foreign currency exchange contracts. The plans' trustee is required to notify the fund manager ten days prior to a withdrawal from the fund. The fund manager retains the right to restrict withdrawals from the fund as not to disadvantage other investors in the fund.

(5) The weighted-average credit quality rating of the pension assets' fixed income security portfolio is investment grade with a weighted-average duration of 5.6 years for 2010 and 5.1 years for 2009.

(6) The weighted-average credit quality rating of the other postretirement benefit assets' fixed income security portfolio is investment grade with a weighted-average duration of 4.8 years for 2010 and 4.5 years for 2009.

The asset's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement.

Shares of the cash management funds are valued at fair value based on published market prices as of the close of business on the last business day of the year, which represents the net asset values of the shares held.

The fair values of equity securities traded on U.S. exchanges are derived from quoted market prices as of the close of business on the last business day of the year. The fair values of equity securities traded on foreign exchanges are also derived from quoted market prices as of the close of business on an active foreign exchange on the last business day of the year. However, the valuation requires translation of the foreign currency to U.S. dollars and this translation is considered an observable input to the valuation.

The fair value of all commingled investment funds has been estimated based on the net asset values per unit of each of the funds. The net asset values per unit of the fund represent the aggregate value of the fund's assets less liabilities, divided by the number of units outstanding. Common stocks traded in active markets comprise the majority of each commingled investment fund's assets. The fair value of these common stocks is derived from quoted market prices as of the close of business on the last business day of the year.

The fair value of fixed income securities, except U.S. Treasury notes and bonds, are determined using pricing models. These pricing models incorporate observable inputs such as benchmark yields, reported trades, broker/dealer quotes, and issuer spreads for similar securities to determine fair value. The U.S. Treasury notes and bonds are valued at fair value based on closing prices on the last business day of the year reported in the active market in which the security is traded.

The investment contracts with insurance companies are valued at fair value by discounting the cash flow of a bond using a yield to maturity based on an investment grade index or comparable index with a similar maturity value, maturity period, and nominal coupon rate.

Plan Benefit Payments and Employer Contributions

Following are the expected benefits to be paid by the plans 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)	
2011	$ 51	$ 18	$ (2)
2012	51	18	(3)
2013	54	18	(3)
2014	68	18	(3)
2015	75	19	(3)
2016-2020	536	107	(20)

In 2011, we expect to contribute approximately $60 million to our tax-qualified pension plans and approximately $7 million to our nonqualified pension plans, for a total of approximately $67 million, and approximately $16 million to our other postretirement benefit plans.

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 plans' guidelines. We match employees' contributions up to certain limits. Our matching contributions charged to expense were $26 million in 2010, $25 million in 2009, and $24 million in 2008. Certain accounts within one of our defined contribution plans have a nonleveraged employee stock ownership plan (ESOP) component. 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. There were no contributions in 2010, 2009, and 2008 to this ESOP, other than dividend reinvestment, as contributions for purchase of our stock are no longer allowed within this defined contribution plan.

Note 8. Inventories

	December 31, 2010	December 31, 2009
	(Millions)	
Natural gas liquids and olefins	$ 87	$ 70
Natural gas in underground storage	93	47
Materials, supplies, and other	123	105
	$303	$222

Note 9. Property, Plant, and Equipment

	Estimated Useful Life (a) (Years)	Depreciation Rates (a) (%)	December 31, 2010	December 31, 2009
			(Millions)	
Nonregulated:				
Oil and gas properties	(b)		$ 11,741	$ 9,854
Natural gas gathering and processing facilities	5 - 40		6,224	5,461
Construction in progress	(c)		865	1,227
Other	3 - 45		940	816
Regulated:				
Natural gas transmission facilities		.01 - 7.25	9,066	8,814
Construction in progress		(c)	240	152
Other		.01 - 33.33	1,359	1,301
Total property, plant, and equipment, at cost			30,435	27,625
Accumulated depreciation, depletion & amortization			(10,163)	(8,981)
Property, plant, and equipment — net			$ 20,272	$18,644

(a) Estimated useful life and depreciation rates are presented as of December 31, 2010. Depreciation rates for regulated assets are prescribed by the FERC.

(b) Oil and gas properties are depleted using the units-of-production method (see Note 1). Balances include $1.9 billion at December 31, 2010, and $864 million at December 31, 2009, of capitalized costs related to properties with unproved reserves or leasehold not yet subject to depletion at Exploration & Production.

(c) Construction in progress balances not yet subject to depreciation and depletion.

On December 21, 2010, we completed the acquisition of 100 percent of the equity of Dakota-3 E&P Company LLC for $949 million, including closing adjustments. This company holds approximately 85,800 net acres on the Fort Berthold Indian Reservation in the Williston basin of North Dakota. Approximately 85 percent of this acreage is undeveloped. This acquisition establishes us in the Bakken Shale oil play and further diversifies our commodity profile. Substantially all of the purchase price was recorded as oil and gas properties within property, plant and equipment by Exploration & Production. Revenues and earnings for the acquired company are insignificant for the three years ended December 31, 2010, 2009 and 2008.

Depreciation, depletion and amortization expense for *property, plant, and equipment — net* was $1.5 billion in 2010, $1.5 billion in 2009, and $1.3 billion in 2008. Oil and gas accounting guidance requires we value our reserves using an average price. This price is calculated using prices at the beginning of the month for the preceding 12 months. This accounting guidance was adopted on a prospective basis in fourth quarter 2009. Adjustments resulting from the implementation of this guidance have not had a material impact on our financial statements.

Regulated *property, plant, and equipment — net* includes $906 million and $946 million at December 31, 2010 and 2009, respectively, related to amounts in excess of the original cost of the regulated facilities within our gas pipeline businesses 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

Our 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, to restore land and remove surface equipment 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.

The following table presents the significant changes to our AROs, of which $750 million and $716 million are included in *other liabilities and deferred income*, with the remaining current portion in *accrued liabilities* at December 31, 2010 and 2009, respectively.

	December 31,	
	2010	2009
	(Millions)	
Beginning balance	$728	$644
Liabilities settled	(18)	(13)
Additions	39	32
Accretion expense	56	51
Revisions(1)	(16)	14
Ending balance	$789	$728

(1) Change in revisions primarily due to the annual review process which considers various factors including inflation rates, current estimates for removal cost, discount rates and the estimated remaining life of the assets. The net downward revision in 2010 includes an offsetting increase of $31 million related to changes in the timing and method of abandonment on certain of Transco's natural gas storage caverns that were associated with a recent leak.

Pursuant to its 2008 rate case settlement, Transco deposits a portion of its collected rates into an external trust (ARO Trust) that is specifically designated to fund future AROs. Transco is also required to make annual deposits into the trust through 2012. (See Note 15).

Property Insurance

The current availability of named windstorm insurance has been significantly reduced from historical levels. Additionally, named windstorm insurance coverage that is available for offshore assets comes at significantly higher premium amounts, higher deductibles and lower coverage limits. Our existing coverage for physical damage to facilities, especially damage to offshore facilities by named windstorms, is limited to $75 million for each occurrence and on an annual aggregate basis in the event of material loss.

Note 10. Accounts Payable and Accrued Liabilities

Under our cash-management system, certain cash accounts reflected negative balances to the extent checks written have not been presented for payment. These negative balances represent obligations and have been reclassified to *accounts payable. Accounts payable* includes $58 million of these negative balances at December 31, 2010 and $44 million at December 31, 2009.

Accrued Liabilities

	December 31,	
	2010	2009
	(Millions)	
Income taxes	$ 275	$112
Interest on debt	162	199
Employee costs	146	158
Taxes other than income taxes	110	176
Other, including other loss contingencies	309	303
	$1,002	$948

Note 11. Debt, Leases, and Banking Arrangements

Long-Term Debt

	Weighted-Average Interest Rate(1)	December 31,	
		2010(2)	2009(2)
		(Millions)	
Secured			
Capital lease obligations	12.0%	$ 4	$ 3
Unsecured			
3.8% to 10.25%, payable through 2040	6.4%	9,104	8,023
Adjustable rate		—	250
Total long-term debt, including current portion		9,108	8,276
Long-term debt due within one year		(508)	(17)
Long-term debt		$8,600	$8,259

(1) At December 31, 2010.

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

Credit Facilities

In conjunction with our restructuring in the first quarter of 2010, we reduced our $1.5 billion unsecured revolving credit facility that expires May 2012 to $900 million and removed Transco and Northwest Pipeline as borrowers. Interest is calculated based on a choice of two methods: a fluctuating rate equal to the lender's base rate plus an applicable margin, or a periodic fixed rate equal to LIBOR plus an applicable margin. We are required to pay a commitment fee (currently 0.125 percent) based on the unused portion of the credit facility. The margins and commitment fee are generally based on our senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include the following:

- Our consolidated ratio of debt to capitalization must be no greater than 65 percent. At December 31, 2010, we are in compliance with this covenant.

In October 2010, unsecured credit facilities totaling $700 million expired and were not renewed. These facilities were originated primarily in support of our former power business.

As part of our strategic restructuring, WPZ entered into a new $1.75 billion three-year senior unsecured revolving credit facility with Transco and Northwest Pipeline as co-borrowers. This credit facility replaced an unsecured $450 million credit facility, comprised of a $200 million revolving credit facility and a $250 million term loan which was terminated as part of the restructuring. At the closing, WPZ utilized $250 million of the credit facility to repay the outstanding term loan. During 2010, WPZ had a maximum of $430 million outstanding under this credit facility, which was primarily used to purchase an additional ownership interest in Overland Pass Pipeline Company LLC (OPPL). At December 31, 2010, the outstanding balance under the credit facility was reduced to zero.

The credit facility may, under certain conditions, be increased by up to an additional $250 million. The full amount of the credit facility is available to WPZ to the extent not otherwise utilized by Transco and Northwest Pipeline. Transco and Northwest Pipeline each have access to borrow up to $400 million under the credit facility to the extent not otherwise utilized by other co-borrowers. Each time funds are borrowed, the borrower may choose from two methods of calculating interest: a fluctuating base rate equal to Citibank N.A's adjusted base rate plus an applicable margin, or a periodic fixed rate equal to LIBOR plus an applicable margin. WPZ is required to pay a commitment fee (currently 0.5 percent) based on the unused portion of the credit facility. The applicable margin and the commitment fee are based on the specific borrower's senior unsecured long-term debt ratings. The credit facility contains various covenants that limit, among other things, a borrower's and its respective subsidiaries' ability to incur indebtedness, grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default, and allow any material change in the nature of its business. Significant financial covenants under the credit facility include:

- WPZ ratio of debt to EBITDA (each as defined in the credit facility, with EBITDA measured on a rolling four-quarter basis) must be no greater than 5 to 1.

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

Each of the above ratios are tested at the end of each fiscal quarter (with the first full year measured on an annualized basis). At December 31, 2010, we are in compliance with these financial covenants.

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

At December 31, 2010, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Expiration	Letters of Credit at December 31, 2010
		(Millions)
$900 million unsecured credit facility	May 1, 2012	$—
$1.75 billion Williams Partners L.P. unsecured credit facility	February 17, 2013	—
Bilateral bank agreements		90
		$90

Exploration & Production's Credit Agreement

Exploration & Production has an unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. In July 2010, the term of this facility expiring in December 2013 was extended to December 2015. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments during an event of default, such as dividends. In December 2010, a waiver with the same terms and restrictions as the original agreement, was executed that will allow us to also hedge up to a certain volume of oil.

Issuances and Retirements

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

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

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

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

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

On November 9, 2010, WPZ completed a public offering of $600 million of 4.125 percent senior notes due 2020. WPZ used the net proceeds to fund part of its acquisition from Exploration & Production of certain gathering and processing assets in the Piceance basin. (See Note 1.)

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)
2011	$507
2012	352
2013	—
2014	—
2015	750

Cash payments for interest (net of amounts capitalized), including amounts related to discontinued operations, were as follows: 2010 — $614 million; 2009 — $592 million; and 2008 — $592 million.

Leases-Lessee

Future minimum annual rentals under noncancelable operating leases as of December 31, 2010, are payable as follows:

	(Millions)
2011	$ 55
2012	44
2013	40
2014	32
2015	27
Thereafter	181
Total	$379

Total rent expense was $61 million in 2010, $70 million in 2009, and $87 million in 2008.

Note 12. Stockholders' Equity

Cash dividends declared per our common share were $.485, $.44 and $.43 for 2010, 2009, and 2008, respectively.

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. During 2007, we purchased 16 million shares for $526 million (including transaction costs) at an average cost of $33.08 per share. During 2008, we purchased 13 million shares of our common stock for $474 million (including transaction costs) at an average cost of $36.76 per share. We completed our $1 billion stock repurchase program in July 2008. Our overall average cost per share was $34.74. This stock repurchase is recorded in *treasury stock* on our Consolidated Balance Sheet.

At December 31, 2010, approximately $22 million of our original $300 million, 5.5 percent junior subordinated convertible debentures, convertible into approximately two million shares of common stock, remain outstanding. In 2009 and 2008, we converted $28 million and $27 million, respectively, of the debentures in exchange for three million and two million shares, respectively, of common stock.

At December 31, 2007, we held all of WPZ's seven million subordinated units outstanding. In February 2008, these subordinated units were converted into common units of WPZ due to the achievement of certain financial targets that resulted in the early termination of the subordination period. While these subordinated units were outstanding, other issuances of partnership units by WPZ had preferential rights and the proceeds from these issuances in excess of the book basis of assets acquired by WPZ were therefore reflected as *noncontrolling interests in consolidated subsidiaries* on our Consolidated Balance Sheet. Due to the conversion of the subordinated units, these original issuances of partnership units no longer have preferential rights and now represent the lowest level of equity securities issued by WPZ. In accordance with our policy in effect at that time regarding the issuance of equity of a consolidated subsidiary, such issuances of nonpreferential equity are accounted for as capital transactions and no gain or loss is recognized. Therefore, as a result of the 2008 conversion, we recognized a decrease to *noncontrolling interests in consolidated subsidiaries* and a corresponding increase to *capital in excess of par value* of approximately $1.2 billion.

We maintain a Stockholder Rights Plan, as amended and restated on September 21, 2004, and further amended May 18, 2007, and October 12, 2007, under which each outstanding share of our common stock has a right (as defined in the plan) attached. Under certain conditions, each right may be exercised to purchase, at an exercise price of $50 (subject to adjustment), one two-hundredth of a share of Series A Junior Participating Preferred Stock. The rights may be exercised only if an Acquiring Person acquires (or obtains the right to acquire) 15 percent or more of our common stock or commences an offer for 15 percent or more of our common stock. The plan contains a mechanism to divest of shares of common stock if such stock in excess of 14.9 percent was acquired inadvertently or without knowledge of the terms of the rights. The rights, which until exercised do not have voting rights, expire in 2014 and may be redeemed at a price of $.01 per right prior to their expiration, or within a specified period of time after the occurrence of certain events. In the event a person becomes the owner of more than 15 percent of our common stock, each holder of a right (except an Acquiring Person) shall have the right to receive, upon exercise, our common stock having a value equal to two times the exercise price of the right. In the event we are engaged in a merger, business combination, or 50 percent or more of our assets, cash flow or earnings power is sold or transferred, each holder of a right (except an Acquiring Person) shall have the right to receive, upon exercise, common stock of the acquiring company having a value equal to two times the exercise price of the right.

Note 13. Stock-Based Compensation

Plan Information

On May 17, 2007, our stockholders approved a plan that provides common-stock-based awards to both employees and nonmanagement directors and reserved 19 million new shares for issuance. On May 20, 2010, our stockholders approved an amendment and restatement of the 2007 plan to increase by 11 million the number of new shares authorized for making awards under the plan, among other changes. The plan permits the granting of various types of awards including, but not limited to, restricted stock units and stock options. At December 31, 2010, 39 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 19 million shares were available for future grants. At December 31, 2009, 30 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 11 million shares were available for future grants.

Additionally, on May 17, 2007, our stockholders approved an Employee Stock Purchase Plan (ESPP) which authorizes up to 2 million new shares of our common stock to be available for sale under the plan. The ESPP enables eligible participants to purchase our common stock through payroll deductions not exceeding an annual amount of $15,000 per participant. The ESPP provides for offering periods during which shares may be purchased and continues until the earliest of: (1) the Board of Directors terminates the ESPP, (2) the sale of all shares available under the ESPP, or (3) the tenth anniversary of the date the Plan was approved by the stockholders. The first offering under the ESPP commenced on October 1, 2007 and ended on December 31, 2007. Subsequent offering periods are from January through June and from July through December. Generally, all employees are eligible to participate in the ESPP, with the exception of executives and international employees. The number of shares eligible for an employee to purchase during each offering period is limited to 750 shares. The purchase price of the stock is 85 percent of the lower closing price of either the first or the last day of the offering period. The ESPP requires a one-year holding period before the stock can be sold. Employees purchased 301 thousand shares at an average price of $15.36 per share during 2010. Approximately 1.0 million and 1.3 million shares were available for purchase under the ESPP at December 31, 2010 and 2009, respectively.

Total stock-based compensation expense for the years ended December 31, 2010, 2009 and 2008 was $48 million, $43 million, and $31 million, respectively. Measured but unrecognized stock-based compensation expense at December 31, 2010, was $46 million, which does not include the effect of estimated forfeitures of $2 million. This amount is comprised of $5 million related to stock options and $41 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.8 years.

Stock Options

The following summary reflects stock option activity and related information for the year ended December 31, 2010.

Stock Options	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
	(Millions)		(Millions)
Outstanding at December 31, 2009	13.0	$16.73	
Granted	1.3	$21.20	
Exercised	(1.2)	$ 6.11	$ 20
Expired	(0.3)	$40.89	
Forfeited	(0.1)	$17.71	
Outstanding at December 31, 2010	12.7	$17.59	$109
Exercisable at December 31, 2010	9.8	$17.44	$ 86

The total intrinsic value of options exercised during the years ended December 31, 2010, 2009, and 2008 was $20 million, $2 million, and $49 million, respectively; and the tax benefit realized was $7 million, $1 million, and $17 million, respectively. Cash received from stock option exercises was $7 million, $2 million, and $32 million during 2010, 2009, and 2008, respectively.

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2010.

	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	Weighted-Average Remaining Contractual Life
	(Millions)		(Years)	(Millions)		(Years)
$2.27 to $11.82	5.4	$ 8.85	4.6	4.0	$ 8.18	3.4
$11.83 to 21.38	4.0	$19.53	5.4	2.8	$18.75	3.6
$21.39 to $30.94	2.0	$25.14	5.3	2.0	$25.14	5.3
$30.95 to $40.51	1.3	$36.17	5.3	1.0	$36.06	4.7
Total	12.7	$17.59	5.0	9.8	$17.44	4.0

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

	2010	2009	2008
Weighted-average grant date fair value of options for our common stock granted during the year	$7.02	$5.60	$12.83
Weighted-average assumptions:			
Dividend yield	2.6%	1.6%	1.2%
Volatility	39.0%	60.8%	33.4%
Risk-free interest rate	3.0%	2.3%	3.5%
Expected life (years)	6.5	6.5	6.5

The expected dividend yield is based on the average annual dividend yield as of the grant date. Expected volatility is based on the historical volatility of our stock and the implied volatility of our stock based on traded options. In calculating historical volatility, returns during calendar year 2002 were excluded as the extreme volatility during that time is not reasonably expected to be repeated in the future. The risk-free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life of the option is based on historical exercise behavior and expected future experience.

Nonvested Restricted Stock Units

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2010.

Restricted Stock Units	Shares	Weighted-Average Fair Value*
	(Millions)	
Nonvested at December 31, 2009	6.1	$16.24
Granted	2.1	$21.05
Forfeited	(0.1)	$19.87
Cancelled	(0.5)	$ 0.00
Vested	(1.0)	$28.67
Nonvested at December 31, 2010	6.6	$16.97

* Performance-based shares are primarily valued using the end-of-period market price until certification that the performance objectives have been completed, a value of zero once it has been determined that it is unlikely that performance objectives will be met, or a valuation pricing model. All other shares are valued at the grant-date market price.

Other restricted stock unit information

	2010	2009	2008
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$21.05	$10.23	$30.13
Total fair value of restricted stock units vested during the year ($'s in millions)	$ 29	$ 28	$ 48

Performance-based shares granted under the Plan represent 26 percent of nonvested restricted stock units outstanding at December 31, 2010. These grants may be earned at the end of a three-year period based on actual performance against a performance target. Expense associated with these performance-based grants is recognized in periods after performance targets are established. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

Note 14. Fair Value Measurements

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

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

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

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

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

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

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis.

	December 31, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Assets:								
Energy derivatives	$ 96	$475	$ 2	$573	$178	$911	$ 5	$1,094
ARO Trust Investments (see Note 15)	40	—	—	40	22	—	—	22
Total assets	$136	$475	$ 2	$613	$200	$911	$ 5	$1,116
Liabilities:								
Energy derivatives	$ 78	$210	$ 1	$289	$177	$826	$ 3	$1,006
Total liabilities	$ 78	$210	$ 1	$289	$177	$826	$ 3	$1,006

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

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

The determination of fair value for our energy derivative assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

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

Forward, swap, and option contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Significant inputs into our Level 2 valuations include commodity prices, implied volatility by location, and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 99 percent of the value of our derivatives portfolio expiring in the next 24 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at December 31, 2010, consist primarily of natural gas index transactions that are used to manage the physical requirements of our Exploration & Production segment.

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers in or out of Level 1 and Level 2 occurred during the year ended December 31, 2010. In 2009, certain Exploration & Production options which hedge future sales of production were transferred from Level 3 to Level 2. These options were originally included in Level 3 because a significant input to the model, implied volatility by location, was considered unobservable. Due to increased transparency, this input was considered observable, and we transferred these options to Level 2.

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

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Years Ended December 31,				
	2010	2009		2008	
	Net Energy Derivatives	Net Energy Derivatives	Other Assets	Net Energy Derivatives	Other Assets
	(Millions)				
Beginning balance	$ 2	$ 507	$ 7	$ (14)	$10
Realized and unrealized gains (losses):					
Included in income (loss) from continuing operations	3	476	—	88	(3)
Included in other comprehensive income (loss)	2	(331)	—	486	—
Purchases, issuances, and settlements	(6)	(477)	(7)	(51)	—
Transfers into Level 3	—	—	—	3	—
Transfers out of Level 3	—	(173)	—	(5)	—
Ending balance	$ 1	$ 2	$—	$507	$ 7
Unrealized gains (losses) included in income (loss) from continuing operations relating to instruments still held at December 31	$—	$ 2	$—	$ —	$—

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

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

	Total Losses For The Years Ended December 31, 2010	2009
	(Millions)	
Impairments:		
Goodwill — Exploration & Production (see Note 4)	$1,003(a)	$ —
Producing properties and acquired unproved reserves — Exploration & Production (see Note 4)	678(b)	15(c)
Certain gathering assets — Williams Partners (see Note 4)	9(d)	—
Venezuelan property — Discontinued Operations (see Note 2)	—	211(e)
Investment in Accroven — Other (see Note 3)	—	75(f)
Cost-based investment — Exploration & Production (see Note 3)	—	11(g)
	$1,690	$312

(a) Due to a significant decline in forward natural gas prices across all future production periods as of September 30, 2010, we performed an interim impairment assessment of the approximate $1 billion of goodwill at Exploration & Production related to its domestic natural gas production operations (the reporting unit). Forward natural gas prices through 2025 as of September 30, 2010, used in our analysis declined more than 22 percent on average compared to the forward prices as of December 31, 2009. We estimated the fair value of the reporting unit on a stand-alone basis by valuing proved and unproved reserves, as well as estimating the fair values of other assets and liabilities which are identified to the reporting unit. We used an income approach (discounted cash flow) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves included reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions in valuing proved reserves included reserves quantities of more than 4.4 trillion cubic feet of gas equivalent; forward prices averaging approximately $4.65 per thousand cubic feet of gas equivalent (Mcfe) for natural gas (adjusted for locational differences), natural gas liquids and oil; and an after-tax discount rate of 11 percent. Unproved reserves (probable and possible) were valued using similar assumptions adjusted further for the uncertainty associated with these reserves by using after- tax discount rates of 13 percent and 15 percent, respectively, commensurate with our estimate of the risk of those reserves. In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its estimated fair value. We then determined that the implied fair value of the goodwill was zero. As a result of our analysis, we recognized a full $1 billion impairment charge related to this goodwill.

(b) As of September 30, 2010, we assessed the carrying value of Exploration & Production's natural gas-producing properties and costs of acquired unproved reserves, for impairments as a result of recent significant declines in forward natural gas prices. Our assessment utilized estimates of future cash flows. Significant judgments and assumptions in these assessments are similar to those used in the goodwill evaluation and include estimates of natural gas reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. The assessment performed at September 30, 2010, identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded a $678 million impairment charge in third-quarter 2010 as further described below. Fair value measured for these properties at September 30, 2010, was estimated to be approximately $320 million.

- $503 million of the impairment charge related to natural gas-producing properties in the Barnett Shale. Significant assumptions in valuing these properties included proved reserves quantities of more than 227 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $4.67 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rate of 11 percent.
- $175 million of the impairment charge related to acquired unproved reserves in the Piceance Highlands acquired in 2008. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent.

(c) Fair value measured at December 31, 2009, was $22 million.

(d) Fair value measured at December 31, 2010, was $3 million.

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

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

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

Note 15. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk

Financial Instruments

Fair-value methods

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

Cash and cash equivalents and restricted cash: The carrying amounts reported in the Consolidated Balance Sheet approximate fair value due to the short-term maturity of these instruments. Current and noncurrent restricted cash is included in *other current assets and deferred charges* and *other assets and deferred charges*, respectively, in the Consolidated Balance Sheet.

ARO Trust Investments: Transco deposits a portion of its collected rates, pursuant to its 2008 rate case settlement, into an external trust specifically designated to fund future asset retirement obligations (ARO Trust). The ARO Trust invests in a portfolio of mutual funds that are reported at fair value in *other assets and deferred charges* in the Consolidated Balance Sheet and are classified as available-for-sale. However, both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

Long-term debt: The fair value of our publicly traded long-term debt is determined using indicative year-end traded bond market prices. Private debt is valued based on market rates and the prices of similar securities with similar terms and credit ratings. At December 31, 2010 and 2009, approximately 100 percent and 97 percent, respectively, of our long-term debt was publicly traded. (See Note 11.)

Guarantees: The *guarantees* represented in the following table consist of a guarantee we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on a certain lease performance obligation. To estimate the fair value of the guarantee, the estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate for each guarantee based on the credit rating of WilTel's current owner and the term of the underlying obligation. The default rates are published by Moody's Investors Service. Guarantees, if recognized, are included in *accrued liabilities* in the Consolidated Balance Sheet.

Other: Includes current and noncurrent notes receivable, margin deposits, customer margin deposits payable, and cost-based investments.

Energy derivatives: Energy derivatives include futures, forwards, swaps, and options. These are carried at fair value in the Consolidated Balance Sheet. See Note 14 for discussion of valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments

	December 31,			
	2010		2009	
Asset (Liability)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions)			
Cash and cash equivalents	$ 795	$ 795	$ 1,867	$ 1,867
Restricted cash (current and noncurrent)	$ 28	$ 28	$ 28	$ 28
ARO Trust Investments	$ 40	$ 40	$ 22	$ 22
Long-term debt, including current portion(a)	$(9,104)	$(9,990)	$(8,273)	$(9,142)
Guarantees	$ (35)	$ (34)	$ (36)	$ (33)
Other	$ (23)	$ (25)(b)	$ (23)	$ (25)(b)
Net energy derivatives:				
Energy commodity cash flow hedges	$ 266	$ 266	$ 178	$ 178
Other energy derivatives	$ 18	$ 18	$ (90)	$ (90)

(a) Excludes capital leases. (See Note 11.)

(b) Excludes certain cost-based investments in companies that are not publicly traded and therefore it is not practicable to estimate fair value. The carrying value of these investments was $2 million at December 31, 2010 and December 31, 2009.

Energy Commodity Derivatives

Risk management activities

We are exposed to market risk from changes in energy commodity prices within our operations. We manage this risk on an enterprise basis and may utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases and sales of natural gas and NGLs attributable to commodity price risk. Certain of these derivatives utilized for risk management purposes have been designated as cash flow hedges, while other derivatives have not been designated as cash flow hedges or do not qualify for hedge accounting despite hedging our future cash flows on an economic basis.

We produce, buy, and sell natural gas at different locations throughout the United States. We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in revenues or margins from fluctuations in natural gas market prices, we enter into natural gas futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. These cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. Our financial option contracts are either purchased options or a combination of options that comprise a net purchased option or a zero-cost collar. Our designation of the hedging relationship and method of assessing effectiveness for these option contracts are generally such that the hedging relationship is considered perfectly effective and no ineffectiveness is recognized in earnings. Hedges for storage contracts have not been designated as cash flow hedges, despite economically hedging the expected cash flows generated by those agreements.

We produce and sell NGLs and olefins at different locations throughout North America. We also buy natural gas to satisfy the required fuel and shrink needed to generate NGLs and olefins. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices or increases in costs and operating expenses from fluctuations in natural gas and NGL market prices, we may enter into NGL or natural gas swap agreements, financial forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs and purchases of natural gas and NGLs. These cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

Other activities

We also enter into energy commodity derivatives for other than risk management purposes, including managing certain remaining legacy natural gas contracts and positions from our former power business and providing services to third parties. These legacy natural gas contracts include substantially offsetting positions and have an insignificant net impact on earnings.

Volumes

Our energy commodity derivatives are comprised of both contracts to purchase the commodity (long positions) and contracts to sell the commodity (short positions). Derivative transactions are categorized into four types:

- Central hub risk: Includes physical and financial derivative exposures to Henry Hub for natural gas, West Texas Intermediate for crude oil, and Mont Belvieu for NGLs;
- Basis risk: Includes physical and financial derivative exposures to the difference in value between the central hub and another specific delivery point;
- Index risk: Includes physical derivative exposure at an unknown future price;
- Options: Includes all fixed price options or combination of options (collars) that set a floor and/or ceiling for the transaction price of a commodity.

Fixed price swaps at locations other than the central hub are classified as both central hub risk and basis risk instruments to represent their exposure to overall market conditions (central hub risk) and specific location risk (basis risk).

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of December 31, 2010. Natural gas is presented in millions of British Thermal Units (MMBtu), and NGLs are presented in gallons. The volumes for options represent at location zero-cost collars and present one side of the short position. The net index position for Exploration & Production includes certain positions on behalf of other segments.

Derivative Notional Volumes		Unit of Measure	Central Hub Risk	Basis Risk	Index Risk	Options
Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(200,100,000)	(200,100,000)		(100,375,000)
Not Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(9,077,499)	(20,195,000)	16,586,059	
Williams Partners	Risk Management	Gallons	(3,990,000)			
Exploration & Production	Other	MMBtu	150,400	(14,766,500)		

Fair values and gains (losses)

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Consolidated Balance Sheet as *current* and *noncurrent derivative assets* and *liabilities*. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	December 31,			
	2010		2009	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Designated as hedging instruments	$288	$ 22	$ 352	$ 174
Not designated as hedging instruments:				
Legacy natural gas contracts from former power business	186	187	505	526
All other	99	80	237	306
Total derivatives not designated as hedging instruments	285	267	742	832
Total derivatives	$573	$289	$1,094	$1,006

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in *AOCI*, *revenues* or *costs and operating expenses*.

	Years Ended December 31,		
	2010	2009	Classification
	(Millions)		
Net gain recognized in other comprehensive income (loss) (effective portion)	$495	$262	AOCI
Net gain reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$342	$618	Revenues or Costs and Operating Expenses
Gain recognized in income (ineffective portion)	$ 9	$ 4	Revenues or Costs and Operating Expenses

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness or as a result of reclassifications to earnings following the discontinuance of any cash flow hedges.

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

	Years Ended December 31,	
	2010	2009
	(Millions)	
Revenues	$46	$37
Costs and operating expenses	28	33
Net gain	$18	$ 4

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

Credit-risk-related features

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

As of December 31, 2010, we have collateral totaling $8 million, all of which is in the form of letters of credit, posted to derivative counterparties to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $36 million, which includes a reduction of less than $1 million to our liability balance for our own nonperformance risk. At December 31, 2009, we had collateral totaling $96 million posted to derivative counterparties, all of which was in the form of letters of credit, to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $167 million, which included a reduction of $3 million to our liability balance for our own nonperformance risk. The additional collateral that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, was $29 million and $74 million at December 31, 2010 and December 31, 2009, respectively.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in AOCI and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. As of December 31, 2010, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to two years. Based on recorded values at December 31, 2010, $148 million of net gains (net of income tax provision of $88 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, 2010. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized within the next year will likely differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Guarantees

In addition to the guarantees and payment obligations discussed in Note 16, we have issued guarantees and other similar arrangements as discussed below.

We are required by our revolving credit agreements to indemnify lenders for any taxes required to be withheld from payments due to the lenders and for any tax payments made by the lenders. The maximum potential amount of future payments under these indemnifications is based on the related borrowings and such future payments cannot currently be determined. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications and have no current expectation of a future claim.

We have provided a guarantee in the event of nonpayment by our previously owned communications subsidiary, WilTel, on a certain lease performance obligation that extends through 2042. The maximum potential exposure is approximately $39 million at December 31, 2010 and $40 million at December 31, 2009. Our exposure declines systematically throughout the remaining term of WilTel's obligation. The carrying value of the guarantee included in *accrued liabilities* on the Consolidated Balance Sheet is $35 million at December 31, 2010 and $36 million at December 31, 2009.

At December 31, 2010, we do not expect these guarantees to have a material impact on our future liquidity or financial position. However, if we are required to perform on these guarantees in the future, it may have a material adverse effect on our results of operations.

Concentration of Credit Risk

Cash equivalents

Our cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

Accounts and notes receivable

The following table summarizes concentration of receivables, net of allowances, by product or service:

	December 31,	
	2010	2009
	(Millions)	
Receivables by product or service:		
Sale of natural gas and related products and services	$635	$599
Transportation of natural gas and related products	149	160
Joint interest	71	56
Other	4	1
Total	$859	$816

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, and Canada. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements, and guarantees of payment by credit worthy parties. The gross credit exposure from our derivative contracts as of December 31, 2010, is summarized as follows:

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 7	$ 8
Energy marketers and traders	—	133
Financial institutions	432	432
	$439	573
Credit reserves		—
Gross credit exposure from derivatives		$573

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of December 31, 2010, excluding collateral support discussed below, is summarized as follows:

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 3	$ 3
Financial institutions	317	317
	$320	320
Credit reserves		—
Net credit exposure from derivatives		$320

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor's rating of BBB- or Moody's Investors Service rating of Baa3 in investment grade.

Our nine largest net counterparty positions represent approximately 99 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are eight counterparty positions, representing 81 percent of our net credit exposure from derivatives, associated with Exploration & Production's hedging facility. Under certain conditions, the terms of this credit agreement may require the participating financial institutions to deliver collateral support to a designated collateral agent (which is another participating financial institution in the agreement). The level of collateral support required is dependent on whether the net position of the counterparty financial institution exceeds specified thresholds. The thresholds may be subject to prescribed reductions based on changes in the credit rating of the counterparty financial institution.

At December 31, 2010, the designated collateral agent holds $19 million of collateral support on our behalf under Exploration & Production's hedging facility. In addition, we hold collateral support, which may include cash or letters of credit, of $15 million related to our other derivative positions.

Revenues

In 2010 we had one customer in our Williams Partners segment that accounted for 10 percent of our consolidated revenues. In 2009, and 2008, there were no customers for which our sales exceeded 10 percent of our consolidated revenues.

Note 16. Contingent Liabilities and Commitments

Issues Resulting from California Energy Crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the FERC. 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.

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. We are currently in settlement negotiations with certain California utilities aimed at eliminating or substantially reducing this exposure. If successful, and subject to a final "true-up" mechanism, the settlement agreement would also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement would resolve most, if not all, of our legal issues arising from the 2000-2001 California Energy Crisis.

As a result of a 2008 U.S. Supreme Court decision, certain contracts that we entered into during 2000 and 2001 might have been subject to partial refunds depending on the results of further proceedings at the FERC. These contracts, under which we sold electricity, totaled approximately $89 million in revenue. While we were not a party to the cases involved in the U.S. Supreme Court decision, the buyer of electricity from us is a party to the cases and claimed that we must refund to the buyer any loss it suffers due to the FERC's reconsideration of the contract terms at issue in the decision. In August 2010, the FERC ruled that settlement of the separate claims against the buyer required the dismissal of the buyer's claims against us.

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

Reporting of Natural Gas-Related Information to Trade Publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states.

- The federal court in Nevada currently presides over cases that were transferred to it from state courts in Colorado, Kansas, Missouri, and Wisconsin. In 2008, the federal court in Nevada granted summary judgment in the Colorado case in favor of us and most of the other defendants, and on January 8, 2009, the court denied the plaintiffs' request for reconsideration of the Colorado dismissal. We expect that the Colorado plaintiffs will appeal, but the appeal cannot occur until the case against the remaining defendant is concluded. In the other cases, our joint motions for summary judgment to preclude the plaintiffs' state law claims based upon federal preemption have been pending since late 2009. If the motions are granted, we expect a final judgment in our favor which the plaintiffs could appeal. If the motions are denied, the current stay of activity would be lifted, class certification would be addressed, and discovery would be completed as the cases proceeded towards trial. Additionally, we would be unable to estimate a revised range of exposure until certain of these matters were resolved. However, it would be reasonably possible that such a range could include levels that would be material to our results of operations.
- On April 23, 2010, the Tennessee Supreme Court reversed the state appellate court and dismissed the plaintiffs' claims against us on federal preemption grounds. The plaintiffs did not appeal this ruling to the United States Supreme Court. This case is now concluded in our favor.

- On September 24, 2010, the Missouri Supreme Court declined to hear the plaintiff's appeal of the trial court's dismissal of a case for lack of standing. The case is now concluded in our favor.

Environmental Matters

Continuing operations

Our interstate gas pipelines are involved in remediation activities related to certain facilities and locations for polychlorinated biphenyl, mercury contamination, and other hazardous substances. These activities have involved the U.S. Environmental Protection Agency (EPA) and various state environmental authorities. At December 31, 2010 we have accrued liabilities of $12 million for these costs. We expect that these costs will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At December 31, 2010, we have accrued liabilities totaling $6 million for these costs.

In March 2008, the EPA proposed a penalty of $370,000 for alleged violations relating to leak detection and repair program delays at our Ignacio gas plant in Colorado and for alleged permit violations at a compressor station. We met with the EPA and are exchanging information in order to resolve the issues.

In September 2007, the EPA requested, and our Transco subsidiary later provided, information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA's investigation of our compliance with the Clean Air Act. On March 28, 2008, the EPA issued notices of violation alleging violations of Clean Air Act requirements at these compressor stations. We met with the EPA in May 2008 and submitted our response denying the allegations in June 2008. In July 2009, the EPA requested additional information pertaining to these compressor stations and in August 2009, we submitted the requested information. On August 20, 2010, the EPA requested and our Transco subsidiary provided, similar information for a compressor station in Maryland.

Former operations, including operations classified as discontinued

We have potential obligations in connection with assets and businesses we no longer operate. These potential obligations include the indemnification of the purchasers of certain of these assets and businesses for environmental and other liabilities existing at the time the sale was consummated. Our responsibilities include those described below.

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

At December 31, 2010, we have accrued environmental liabilities of $31 million related to these matters.

Actual costs 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. Any incremental amount cannot be reasonably estimated at this time.

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.

Environmental matters — general

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, new air quality standards for ground level ozone, and one hour nitrogen dioxide emission limits. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Other Legal Matters

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay (a joint venture between Gulsby and Bay Ltd.) for the construction of certain gas processing plants in Louisiana. National American Insurance Company (NAICO) and American Home Assurance Company provided payment and performance bonds for the projects. In 2001, the contractors and sureties filed multiple cases in Louisiana and Texas against Gulf Liquids and us.

In 2006, at the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual and punitive damages verdict against us and Gulf Liquids. Based on our interpretation of the jury verdicts, we recorded a charge based on our estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $20 million. In addition, we concluded that it was reasonably possible that any ultimate judgment might have included additional amounts of approximately $199 million in excess of our accrual, which primarily represented our estimate of potential punitive damage exposure under Texas law.

From May through October 2007, the court entered seven post-trial orders in the case (interlocutory orders) which, among other things, overruled the verdict award of tort and punitive damages as well as any damages against us. The court also denied the plaintiffs' claims for attorneys' fees. On January 28, 2008, the court issued its judgment awarding damages against Gulf Liquids of approximately $11 million in favor of Gulsby and approximately $4 million in favor of Gulsby-Bay. Gulf Liquids, Gulsby, Gulsby-Bay, Bay Ltd., and NAICO appealed the judgment. In February 2009, we settled with certain of these parties and reduced our liability as of December 31, 2008, by $43 million, including $11 million of interest. On February 17, 2011, the Texas Court of Appeals upheld the dismissals of the tort and punitive damages claims and reversed and remanded the contract claim and attorney fee claims for further proceedings. The appellate court ruling is subject to a potential appeal to the Texas Supreme Court. If the appellate court judgment is upheld, our remaining liability will be substantially less than the amount of our accrual for these matters.

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in Colorado state court alleging that we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. We reached a final partial settlement agreement for an amount that was previously accrued. We received a favorable ruling on our motion for summary judgment on one claim now on appeal by plaintiffs. We anticipate trial on the other remaining issue related to royalty payment calculation and obligations under specific lease provisions in 2011. While we are not able to estimate the amount of any additional exposure at this time, it is reasonably possible that plaintiff's claims could reach a material amount.

Other producers have been in litigation or discussions with a federal regulatory agency and a state agency in New Mexico regarding certain deductions used in the calculation of royalties. Although we are not a party to these matters, we have monitored them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. One of these matters involving federal litigation was decided on October 5,

2009. The resolution of this specific matter is not material to us. However, other related issues in these matters that could be material to us remain outstanding. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue (ONRR) in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The ONRR's guidance provides its view as to how much of a producer's bundled fees for transportation and processing can be deducted from the royalty payment. Using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states, but such guidelines are expected in the future. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments and the effect could be material to our results of operations.

Other

In 2003, we entered into an agreement to sublease certain underground storage facilities to Liberty Gas Storage (Liberty). We have asserted claims against Liberty for prematurely terminating the sublease, and for damage caused to the facilities. In February 2010, Liberty subsequently indicated that they intend to assert a counterclaim for costs in excess of $200 million associated with its use of the facilities. Due to the lack of information currently available, we are unable to evaluate the merits of the potential counterclaim and determine the amount of any possible liability.

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, property damage, environmental matters, right of way and other representations that we have provided.

At December 31, 2010, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

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

Summary

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

Commitments

Commitments for construction and acquisition of property, plant and equipment are approximately $226 million at December 31, 2010.

As part of managing our commodity price risk, we utilize contracted pipeline capacity primarily to move our natural gas production to other locations with more favorable pricing differentials. Our commitments under these contracts are as follows:

	(Millions)
2011	$ 143
2012	137
2013	125
2014	127
2015	120
Thereafter	404
Total	$1,056

We also have certain commitments to an equity investee for natural gas gathering and treating services which total $181 million over approximately seven years.

Note 17. Accumulated Other Comprehensive Loss

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

	Income (Loss)						
			Pension Benefits		Other Postretirement Benefits		
	Cash Flow Hedges	Foreign Currency Translation	Prior Service Cost	Net Actuarial Gain (Loss)	Prior Service Cost	Net Actuarial Gain (Loss)	Total
				(Millions)			
Balance at December 31, 2007	$(157)	$129	$(4)	$ (97)	$(3)	$ 11	$(121)
2008 Change:							
Pre-income tax amount	714	(76)	—	(565)	16	(15)	74
Income tax (provision) benefit	(270)	—	—	213	(8)	6	(59)
Net reclassification into earnings of derivative instrument losses (net of a $7 million income tax benefit)	11	—	—	—	—	—	11
Amortization included in net periodic benefit expense	—	—	1	13	1	—	15
Income tax provision on amortization	—	—	—	(5)	—	—	(5)
	455	(76)	1	(344)	9	(9)	36
Allocation of other comprehensive income (loss) to noncontrolling interests	(2)	—	—	7	—	—	5
Balance at December 31, 2008	296	53	(3)	(434)	6	2	(80)
2009 Change:							
Pre-income tax amount	262	83	—	44	7	(1)	395
Income tax (provision) benefit	(99)	—	—	(17)	—	1	(115)
Net reclassification into earnings of derivative instrument gains (net of a $234 million income tax provision)	(384)	—	—	—	—	—	(384)
Amortization included in net periodic benefit expense	—	—	1	42	(4)	—	39
Income tax (provision) benefit on amortization	—	—	(1)	(16)	1	—	(16)
	(221)	83	—	53	4	—	(81)
Allocation of other comprehensive income to noncontrolling interests	—	—	—	(7)	—	—	(7)
Balance at December 31, 2009	75	136	(3)	(388)	10	2	(168)

	Income (Loss)						
			Pension Benefits		Other Postretirement Benefits		
	Cash Flow Hedges	Foreign Currency Translation	Prior Service Cost	Net Actuarial Gain (Loss)	Prior Service Cost	Net Actuarial Gain (Loss)	Total
	(Millions)						
2010 Change:							
Pre-income tax amount	488	29	—	(71)	—	(12)	434
Income tax (provision) benefit	(185)	—	—	24	—	3	(158)
Net reclassification into earnings of derivative instrument gains (net of a $131 million income tax provision)	(211)	—	—	—	—	—	(211)
Amortization included in net periodic benefit expense	—	—	1	35	(5)	1	32
Income tax (provision) benefit on amortization	—	—	—	(13)	2	—	(11)
	92	29	1	(25)	(3)	(8)	86
Allocation of other comprehensive income to noncontrolling interests	—	—	—	—	—	—	—
Balance at December 31, 2010	$ 167	$165	$ (2)	$(413)	$ 7	$ (6)	$ (82)

Note 18. Segment Disclosures

Our reporting segments are Williams Partners, Exploration & Production, and Other. (See Note 1.)

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

Due to expected future growth in our Canadian midstream and domestic olefins operations, we are considering reporting these businesses as a separate segment in the first quarter of 2011.

Performance Measurement

We currently evaluate performance based upon *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses*, *equity earnings (losses)* and *income (loss) from investments*. The accounting policies of the segments are the same as those described in Note 1. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

The primary types of costs and operating expenses by segment can be generally summarized as follows:

- Williams Partners — commodity purchases (primarily for NGL and crude marketing, shrink and fuel), depreciation and operation and maintenance expenses;
- Exploration & Production — commodity purchases (primarily in support of commodity marketing and risk management activities), depletion, depreciation and amortization, lease and facility operating expenses and operating taxes;
- Other — commodity purchases (primarily for shrink, feedstock and NGL and olefin marketing activities), depreciation and operation and maintenance expenses.

Energy commodity hedging by our business units may be done through intercompany derivatives with our Exploration & Production segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Additionally, Exploration & Production may enter into transactions directly with third parties under their credit agreement. (See Note 11.) Exploration & Production bears the counterparty performance risks associated with the unrelated third parties in these transactions.

The following geographic area data includes *revenues from external customers* based on product shipment origin and *long-lived assets* based upon physical location.

	United States	Other (Millions)	Total
Revenues from external customers:			
2010	$ 9,359	$257	$ 9,616
2009	8,065	190	8,255
2008	11,629	261	11,890
Long-lived assets:			
2010	$19,791	$527	$20,318
2009	19,247	410	19,657
2008	18,419	335	18,754

Our foreign operations are primarily located in Canada and South America. *Long-lived assets* are comprised of property, plant, and equipment, goodwill, and other intangible assets.

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

	Williams Partners*	Exploration & Production*	Other	Eliminations*	Total
			(Millions)		
2010					
Segment revenues:					
External	$5,344	$ 3,245	$1,027	$ —	$ 9,616
Internal	371	797	30	(1,198)	—
Total revenues	$5,715	$ 4,042	$1,057	$(1,198)	$ 9,616
Segment profit (loss)	$1,574	$(1,343)	$ 240	$ —	$ 471
Less:					
Equity earnings (losses)	109	20	34	—	163
Income (loss) from investments	—	—	43	—	43
Segment operating income (loss)	$1,465	$(1,363)	$ 163	$ —	265
General corporate expenses					(221)
Total operating income (loss)					$ 44
Other financial information:					
Additions to long-lived assets **	$ 904	$ 2,859	$ 129	$ —	$ 3,892
Depreciation, depletion & amortization	$ 568	$ 895	$ 44	$ —	$ 1,507
2009					
Segment revenues:					
External	$4,359	$ 3,143	$ 753	$ —	$ 8,255
Internal	243	541	27	(811)	—
Total revenues	$4,602	$ 3,684	$ 780	$ (811)	$ 8,255
Segment profit (loss)	$1,317	$ 391	$ (2)	$ —	$ 1,706
Less:					
Equity earnings (losses)	81	18	37	—	136
Income (loss) from investments	—	—	(75)	—	(75)
Segment operating income (loss)	$1,236	$ 373	$ 36	$ —	1,645
General corporate expenses					(164)
Total operating income (loss)					$ 1,481
Other financial information:					
Additions to long-lived assets	$1,023	$ 1,304	$ 70	$ —	$ 2,397
Depreciation, depletion & amortization	$ 553	$ 868	$ 40	$ —	$ 1,461
2008					
Segment revenues:					
External	$5,545	$ 5,130	$1,215	$ —	$11,890
Internal	302	1,065	42	(1,409)	—
Total revenues	$5,847	$ 6,195	$1,257	$(1,409)	$11,890
Segment profit (loss)	$1,425	$ 1,253	$ 142	$ —	$ 2,820
Less:					
Equity earnings (losses)	76	20	41	—	137
Income (loss) from investments	—	—	1	—	1
Segment operating income (loss)	$1,349	$ 1,233	$ 100	$ —	2,682
General corporate expenses					(149)
Total operating income (loss)					$ 2,533
Other financial information:					
Additions to long-lived assets	$1,212	$ 2,418	$ 64	$ —	$ 3,694
Depreciation, depletion & amortization	$ 518	$ 723	$ 39	$ —	$ 1,280

* 2009 and 2008 recast as discussed in Note 1.

** Does not include WPZ's purchase of a business represented by certain gathering and processing assets in Colorado's Piceance basin from Exploration & Production. (See Note 1.)

Total segment revenues for Exploration & Production include $1,743 million, $1,456 million and $3,244 million of gas management revenues for the years ended December 31, 2010, 2009 and 2008, respectively. Gas management revenues include sales of natural gas in conjunction with marketing services provided to third parties and intercompany sales of fuel and shrink gas to the midstream businesses in Williams Partners. These revenues are substantially offset by similar amounts of gas management costs.

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

	Total Assets			Equity Method Investments		
	December 31, 2010	December 31, 2009	December 31, 2008	December 31, 2010	December 31, 2009	December 31, 2008
			(Millions)			
Williams Partners*	$13,396	$12,472	$12,167	$1,045	$593	$524
Exploration & Production*	9,827	10,084	11,155	104	95	87
Other	4,178	4,192	3,696	193	196	336
Eliminations	(2,429)	(1,469)	(1,541)	—	—	—
Discontinued Operations	—	1	529	—	—	—
Total	$24,972	$25,280	$26,006	$1,342	$884	$947

* 2009 and 2008 Total Assets recast as discussed in Note 1.

Note 19. Subsequent Events

On February 16, 2011, we announced that our Board of Directors approved pursuing a plan to separate the company into two standalone, publicly traded corporations. The plan calls for the separation of our exploration and production business into a publicly traded company via an initial public offering of up to 20 percent of our interest in the third quarter of 2011. We intend to complete the offering so that it preserves our ability to complete a tax-free spinoff of our remaining ownership in the exploration and production business to Williams' shareholders in 2012, after which Williams would continue as a premier natural gas infrastructure company. We retain the discretion to determine whether and when to execute the spinoff.

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA
(Unaudited)

Summarized quarterly financial data are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Millions, except per-share amounts)			
2010				
Revenues	$2,596	$2,292	$ 2,304	$2,424
Costs and operating expenses	1,922	1,723	1,752	1,788
Income (loss) from continuing operations	(148)	224	(1,221)	229
Net income (loss)	(146)	222	(1,226)	228
Amounts attributable to The Williams Companies, Inc.:				
Income (loss) from continuing operations	(195)	187	(1,258)	175
Net income (loss)	(193)	185	(1,263)	174
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	(0.33)	0.32	(2.15)	0.30
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	(0.33)	0.31	(2.15)	0.29
2009				
Revenues	$1,922	$1,909	$ 2,098	$2,326
Costs and operating expenses	1,444	1,392	1,537	1,708
Income from continuing operations	19	151	192	222
Net income (loss)	(224)	169	194	222
Amounts attributable to The Williams Companies, Inc.:				
Income from continuing operations	2	123	141	172
Net income (loss)	(172)	142	143	172
Basic earnings per common share:				
Income from continuing operations	—	0.21	0.24	0.30
Diluted earnings per common share:				
Income from continuing operations	—	0.21	0.24	0.29

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 2010 includes the following pre-tax items:

- $19 million unfavorable adjustment to depletion expense related to a correction of prior years' production volumes used in the calculation of depletion expense at Exploration & Production (see Note 4 of Notes to Consolidated Financial Statements);
- $11 million unfavorable adjustment to depreciation, depletion and amortization expense related to a correction of prior years' costs used in the calculation of depreciation, depletion, and amortization expenses at Exploration & Production.

Net income for fourth-quarter 2010 also includes the following tax adjustments:

- $66 million provision to reflect taxes on undistributed earnings of certain foreign operations that are no longer consider permanently reinvested (see Note 5);
- $65 million benefit to decrease state income taxes (net of federal benefit) due to a reduction in our estimate of the effective deferred state rate, including state income tax carryovers (see Note 5).

Net loss for third-quarter 2010 includes the following pre-tax items:

- $1,003 million impairment of goodwill at Exploration & Production (see Notes 4 and 14);

- $678 million of impairments of certain producing properties and acquired unproved reserves at Exploration & Production (see Note 4);
- $30 million gain related to the sale of our 50 percent interest in Accroven at Other (see Note 3);
- $15 million of exploratory dry hole costs at Exploration & Production (see Note 4);
- $12 million gain on the sale of certain assets at Williams Partners (see Note 4).

Net income for second-quarter 2010 includes the following pre-tax items:

- $13 million gain related to the sale of our 50 percent interest in Accroven at Other (see Note 3);
- $11 million of involuntary conversion gains due to insurance recoveries that are in excess of the carrying value of assets at Williams Partners (see Note 4).

Net loss for first-quarter 2010 includes the following pre-tax items:

- $606 million of early debt retirement costs consisting primarily of cash premiums of $574 million (see Note 4);
- $39 million of other transaction costs associated with our strategic restructuring transaction, of which $4 million are attributable to noncontrolling interests (see Note 4);
- $4 million of accelerated amortization of debt costs related to amendments of credit facilities (see Note 4).

Net income for fourth-quarter 2009 includes the following pre-tax items:

- $40 million gain related to the sale of our Cameron Meadows processing plant at Williams Partners (see Note 4);
- $17 million unfavorable depletion adjustment at Exploration & Production primarily as the result of new oil and gas accounting guidance that requires we value our reserves using an average price;
- $15 million impairment of certain natural gas properties at Exploration & Production (see Note 4).

Net income for second-quarter 2009 includes the following pre-tax items:

- $15 million gain related to our former coal operations (see summarized results of discontinued operations at Note 2);
- $11 million of income related to the recovery of certain royalty overpayments from prior periods at Exploration & Production.

Net loss for first-quarter 2009 includes the following pre-tax items:

- $211 million impairment of Venezuela property, plant, and equipment (see summarized results of discontinued operations at Note 2);
- $75 million impairment of a Venezuelan investment in Accroven at Other (see Note 3);
- $48 million of bad debt expense related to our discontinued Venezuela operations (see summarized results of discontinued operations at Note 2);
- $30 million net charge related to the write-off of certain deferred charges related to our discontinued Venezuela operations (see summarized results of discontinued operations at Note 2);
- $34 million of penalties from early release of drilling rigs at Exploration & Production (see Note 4);
- $11 million impairment of a Venezuelan cost-based investment at Exploration & Production (see Note 3).

Net loss for first-quarter 2009 also includes a $76 million benefit from the reversal of deferred tax balances related to our discontinued Venezuela operations (see summarized results of discontinued operations at Note 2).

THE WILLIAMS COMPANIES, INC.
SUPPLEMENTAL OIL AND GAS DISCLOSURES
(Unaudited)

We have significant oil and gas producing activities primarily in the Rocky Mountain, Northeast and Mid-continent areas of the United States. Additionally, we have international oil and gas producing activities, primarily in Argentina. Proved reserves and revenues related to international activities are approximately five percent and three percent, respectively, of our total international and domestic proved reserves and revenues from producing activities. Accordingly, the following information relates only to the oil and gas activities in the United States. This information also excludes our gas management activities.

Capitalized Costs

	As of December 31, 2010	2009
	(Millions)	
Proved Properties	$ 9,780	$ 9,165
Unproved properties	2,170	953
	11,950	10,118
Accumulated depreciation, depletion and amortization and valuation provisions	(3,864)	(3,212)
Net capitalized costs	$ 8,086	$ 6,906

- Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $320 million and $272 million, net, for 2010 and 2009, respectively.
- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells including uncompleted development well costs, and successful exploratory wells.
- Unproved properties consist primarily of unproved leasehold costs and costs for acquired unproven reserves.

Cost Incurred

	For The Year Ended December 31, 2010	2009	2008
		(Millions)	
Acquisition	$1,731	$ 305	$ 543
Exploration	22	51	38
Development	988	878	1,699
	$2,741	$1,234	$2,280

- Costs incurred include capitalized and expensed items.
- Acquisition costs are as follows: The 2010 costs are primarily for additional leasehold in the Williston and Marcellus basins and include approximately $355 million of proved property values. The 2009 costs are primarily for additional leasehold and reserve acquisitions in the Piceance basin, and include $85 million of proved property values. The 2008 costs are primarily for additional leasehold and reserve acquisitions in the Piceance and Fort Worth basins. Included in the 2008 acquisition amounts is $140 million of proved property values and $71 million related to an interest in a portion of acquired assets that a third party subsequently exercised its contractual option to purchase from us, on the same terms and conditions.

- Exploration costs include the costs incurred for geological and geophysical activity, drilling and equipping exploratory wells, including costs incurred during the year for wells determined to be dry holes, exploratory lease acquisitions, and retaining undeveloped leaseholds.
- Development costs include costs incurred to gain access to and prepare well locations for drilling and to drill and equip wells in our development basins.

Results of Operations

	For The Year Ended December 31, 2010	2009	2008
		(Millions)	
Revenues:			
Oil and gas revenues	$2,160	$2,093	$2,819
Other revenues	23	42	31
Total revenues	2,183	2,135	2,850
Costs:			
Production costs	776	627	741
General & administrative	154	151	158
Exploration expenses	61	58	27
Depreciation, depletion & amortization	878	851	709
Impairment of certain natural gas properties in the Fort Worth basin	503	—	—
Write down of costs associated with acquired unproven reserves	175	15	—
Impairment of certain natural gas properties in the Arkoma basin	1	—	143
Other (income) expense	(6)	34	2
Total costs	2,542	1,736	1,780
Results of operations	(359)	399	1,070
(Provision) benefit for income taxes	134	(151)	(404)
Exploration and production net income (loss)	$ (225)	$ 248	$ 666

- Results of operations for producing activities consist of all related domestic oil and gas producing activities. Prior periods have been recast to reflect the impact of the sale of certain Piceance gathering and processing facilities to WPZ. Amounts for 2010 exclude a $1 billion impairment charge related to goodwill associated with the purchase of Barrett Resources Corporation (Barrett) in 2001. Amounts for 2008 exclude a $148 million gain on sale of a contractual right to a production payment on certain future international hydrocarbon production.
- Oil and gas revenues consist primarily of natural gas production sold and includes the impact of hedges.
- Other revenues consist of activities that are not a direct part of the producing activities. Other expenses in 2009 also include $32 million of expense related to penalties from the early release of drilling rigs.
- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of natural gas. These costs also include production taxes other than income taxes, gathering, processing and transportation expenses (excluding charges for unutilized pipeline capacity), and administrative expenses in support of production activity. Excluded are depreciation, depletion and amortization of capitalized costs.
- Exploration expenses include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes, and the cost of retaining undeveloped leaseholds including lease amortization and impairments.

- Depreciation, depletion and amortization includes depreciation of support equipment. Amounts for 2010 include $26 million related to corrections of prior years' production volumes and costs used in the calculation of depreciation, depletion and amortization expense. Additionally, 2009 includes $17 million additional depreciation, depletion and amortization as a result of our recalculation of fourth quarter depreciation, depletion and amortization utilizing our year-end reserves which were lower than 2008. The lower reserves in 2009 were primarily a result of the application of new rules issued by the SEC in 2009.

Proved Reserves

	2010	2009	2008
		(Bcfe)	
Proved reserves at the beginning of period	4,255	4,339	4,143
Revisions	(233)	(859)	(220)
Purchases	162	159	31
Extensions and discoveries	508	1,051	791
Wellhead production	(420)	(435)	(406)
Proved reserves at the end of period	4,272	4,255	4,339
Proved developed reserves at end of period	2,498	2,387	2,456

- The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. 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 generally limited to those that can be developed within five years according to planned drilling activity. Proved reserves on undrilled acreage also can include locations that are more than one offset away from current producing wells where there is a reasonable certainty of production when drilled or where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation.

- Revisions in 2010 primarily relate to the reclassification of reserves from proved to probable reserves attributable to locations not expected to be developed within five years. A significant portion of the revisions for 2009 are a result of the impact of the new SEC rules. Proved reserves are lower because of the lower 12-month average, first-of-the-month price as compared to the 2008 year-end price, and the revision of proved undeveloped reserve estimates based on new guidance. Approximately one-half of the revisions for 2008 relate to the impact of lower average year-end natural gas prices used in 2008 compared to the 2007.

- Extensions and discoveries in 2009 are higher than other years due in part to the expanded definition of oil and gas reserves supported by reliable technology and reasonable certainty used for reserves estimation.

- 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. In 2009, we adopted prescribed accounting revisions associated with oil and gas authoritative guidance. Those revisions include using the 12-month average price computed as an unweighted arithmetic average of the price as of the first day of each month, unless prices are defined by contractual arrangements. These revisions are reflected in our 2010 and 2009 amounts. For the years ended December 31, 2010 and 2009, the average natural gas equivalent price used in the estimates was $3.78 and $2.76 per MMcfe, respectively. For the year ended December 31, 2008, the average year-end natural gas equivalent price used in the estimates was $4.41 per MMcfe. Future income tax expenses have been computed considering applicable taxable cash flows and appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by authoritative guidance. 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 $2,960 million of future development costs, approximately 57 percent is estimated to be spent in 2011, 2012, and 2013.

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,	
	2010	2009
	(Millions)	
Future cash inflows	$16,151	$11,729
Less:		
Future production costs	4,927	3,990
Future development costs	2,960	2,833
Future income tax provisions	2,722	1,404
Future net cash flows	5,542	3,502
Less 10 percent annual discount for estimated timing of cash flows	(2,728)	(1,789)
Standardized measure of discounted future net cash inflows	$ 2,814	$ 1,713

Sources of Change in Standardized Measure of Discounted Future Net Cash Flows

	2010	2009	2008
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 1,713	$ 3,173	$ 4,803
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,446)	(1,006)	(2,091)
Net change in prices and production costs	1,921	(3,310)	(2,548)
Extensions, discoveries and improved recovery, less estimated future costs	724	1,131	1,423
Development costs incurred during year	633	389	817
Changes in estimated future development costs	(292)	701	(724)
Purchase of reserves in place, less estimated future costs	439	171	55
Revisions of previous quantity estimates	(332)	(923)	(395)
Accretion of discount	220	450	714
Net change in income taxes	(758)	932	1,108
Other	(8)	5	11
Net changes	1,101	(1,460)	(1,630)
Standardized measure of discounted future net cash flows end of period	$ 2,814	$ 1,713	$ 3,173

In relation to the SEC rules adopted in 2009, we estimated that the standardized measure of discounted future net cash flows in 2009 declined approximately $840 million on a before tax basis and excluding the overall price rule impact. The significant components of this decline included an estimated $640 million decrease included in revisions of previous quantity estimates and a related $430 million decrease included in the net change in prices and production costs, partially offset by a $210 million increase included in extensions, discoveries and improved recovery, less estimated future costs. Additionally, we estimated that a significant portion of the remaining net change in price and production costs is due to the application of the new pricing rules which resulted in the use of lower prices at December 31, 2009, than would have resulted under the previous rules.

THE WILLIAMS COMPANIES, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	ADDITIONS Charged (Credited) To Costs and Expenses	ADDITIONS Other	Deductions	Ending Balance
		(Millions)			
2010:					
Allowance for doubtful accounts - accounts and notes receivable(a)	$ 22	$ (6)	$—	$ 1(c)	$ 15
Deferred tax asset valuation allowance(a)	289	(40)	—	—	249
Price-risk management credit reserves — liabilities(b)	(3)	3(d)	—	—	—
2009:					
Allowance for doubtful accounts -accounts and notes receivable(a)	29	4	—	11(c)	22
Deferred tax asset valuation allowance(a)	224	65	—	—	289
Price-risk management credit reserves — assets(a)	6	(3)(d)	(3)(e)	—	—
Price-risk management credit reserves — liabilities(b)	(15)	12(d)	—	—	(3)
2008:					
Allowance for doubtful accounts - accounts and notes receivable(a)	16	15	—	2(c)	29
Deferred tax asset valuation allowance(a)	274	(14)	—	36(c)	224
Price-risk management credit reserves — assets(a)	1	1(d)	4(e)	—	6
Price-risk management credit reserves — liabilities(b)	—	(16)(d)	1(e)	—	(15)

(a) Deducted from related assets.

(b) Deducted from related liabilities.

(c) Represents balances written off, reclassifications and recoveries.

(d) Included in *revenues.*

(e) Included in *accumulated other comprehensive income (loss).*

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) (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.

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

Management's Annual Report on Internal Control over Financial Reporting

See report set forth above in Item 8, "Financial Statements and Supplementary Data."

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

See report set forth above in Item 8, "Financial Statements and Supplementary Data."

Changes in Internal Controls Over Financial Reporting

There have been no changes during the fourth quarter of 2010 that have materially affected, or are reasonably likely to materially affect, our Internal Controls over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information regarding our directors and nominees for director required by Item 401 of Regulation S-K will be presented under the heading. "Proposal 1 — Election of Directors" in our Proxy Statement prepared for the solicitation of proxies in connection with our Annual Meeting of Stockholders to be held May 19, 2011 (Proxy Statement), which information is incorporated by reference herein.

Information regarding our executive officers required by Item 401(b) of Regulation S-K is presented at the end of Part I herein and captioned "Executive Officers of the Registrant" as permitted by General Instruction G(3) to Form 10-K and Instruction 3 to Item 401(b) of Regulation S-K.

Information required by Item 405 of Regulation S-K will be included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement, which information is incorporated by reference herein.

Information required by paragraphs (c)(3), (d)(4) and (d)(5) of Item 407 of Regulation S-K will be included under the heading "Questions and Answers About the Annual Meeting and Voting" and "Corporate Governance and Board Matters" in our Proxy Statement, which information is incorporated by reference herein.

We have adopted a Code of Ethics for Senior Officers that applies to our Chief Executive Officer, Chief Financial Officer, and Controller, or persons performing similar functions. The Code of Ethics for Senior Officers, 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 Corporate Secretary at Williams, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Controller, and persons performing similar functions on our Internet website at *http://www.williams.com* under the Investor Relations caption, promptly following the date of any such amendment or waiver.

Item 11. *Executive Compensation*

The information required by Item 402 and paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K regarding executive compensation will be presented under the headings "Compensation Discussion and Analysis," "Executive Compensation and Other Information," "Compensation of Directors," and "Compensation Committee Report on Executive Compensation" in our Proxy Statement, which information is incorporated by reference herein. Notwithstanding the foregoing, the information provided under the heading "Compensation Committee Report on Executive Compensation" in our Proxy Statement is furnished and shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information regarding securities authorized for issuance under equity compensation plans required by Item 201(d) of Regulation S-K and the security ownership of certain beneficial owners and management required by Item 403 of Regulation S-K will be presented under the headings "Equity Compensation Stock Plans" and "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement, which information is incorporated by reference herein.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information regarding certain relationships and related transactions required by Item 404 and Item 407(a) of Regulation S-K will be presented under the heading "Corporate Governance and Board Matters" in our Proxy Statement, which information is incorporated by reference herein.

Item 14. *Principal Accountant 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 "Ratification of the Appointment of Independent Auditors — Principal Accounting Fees and Services" in our Proxy Statement, which information is incorporated by reference herein.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) 1 and 2.

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Covered by report of independent auditors:	
Consolidated statement of operations for each year in the three-year period ended December 31, 2010	84
Consolidated balance sheet at December 31, 2010 and 2009	85
Consolidated statement of changes in equity for each year in the three-year period ended December 31, 2010	86
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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	—	Amended and Restated Certificate of Incorporation, as supplemented (filed on May 26, 2010 as Exhibit 3.1 to the Company's Form 8-K) and incorporated herein by reference.
3.2	—	By-Laws (filed on May 26, 2010 as Exhibit 3.2 to the Company's Current Report on Form 8-K) and incorporated herein by reference.
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 on September 8, 1997 as Exhibit 4.1 to The Williams Companies, Inc.'s Form S-3) and incorporated herein by reference.
4.2	—	Fifth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed on March 12, 2001 as Exhibit 4(k) to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
4.3	—	Seventh Supplemental Indenture dated March 19, 2002, between The Williams Companies, Inc. as Issuer and Bank One Trust Company, National Association, as Trustee (filed on May 9, 2002 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
4.4	—	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 February 25, 1997 as Exhibit 4.4.1 to MAPCO Inc.'s Amendment No. 1 to Form S-3) and incorporated herein by reference.
4.5	—	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) and incorporated herein by reference.

Exhibit No.		Description
4.6	—	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) and incorporated herein by reference.
4.7	—	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) and incorporated herein by reference.
4.8	—	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 on March 28, 2000 as Exhibit 4(q) to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
4.9	—	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 on August 12, 2003 as Exhibit 4.2 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
4.10	—	Indenture dated as of March 5, 2009, among The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee (filed on March 11, 2009 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.11	—	Eleventh Supplemental Indenture dated as of February 1, 2010 between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.12	—	First Supplemental Indenture dated as of February 1, 2010 between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010 as Exhibit 4.2 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.13	—	Fifth Supplemental Indenture dated as of February 1, 2010 between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010 as Exhibit 4.3 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.14	—	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 on September 24, 2004 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.15	—	Amendment No. 1 dated May 18, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed on May 22, 2007 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.16	—	Amendment No. 2 dated October 12, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed on October 15, 2007 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.17	—	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 September 14, 1995 as Exhibit 4.1 to Northwest Pipeline's Form S-3) and incorporated herein by reference.
4.18	—	Indenture dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee, with regard to Northwest Pipeline's $175 million aggregate principal amount of 7.00% Senior Notes due 2016 (filed on June 23, 2006 as Exhibit 4.1 to Northwest Pipeline's Form 8-K) and incorporated herein by reference.
4.19	—	Indenture, dated as of April 5, 2007, between Northwest Pipeline Corporation and The Bank of New York (filed on April 5, 2007 as Exhibit 4.1 to Northwest Pipeline Corporation's Form 8-K) (Commission File number 001-07414) and incorporated herein by reference.

Exhibit No.		Description
4.20	—	Indenture dated May 22, 2008, between Northwest Pipeline GP and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Northwest Pipeline GP's Form 8-K) and incorporated herein by reference.
4.21	—	Senior Indenture dated as of July 15, 1996 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on April 2, 1996 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-3) and incorporated herein by reference.
4.22	—	Indenture dated as of August 27, 2001 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on November 8, 2001 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-4) and incorporated herein by reference.
4.23	—	Indenture dated as of July 3, 2002 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed August 14, 2002 as Exhibit 4.1 to The Williams Companies Inc.'s Form 10-Q) and incorporated herein by reference.
4.24	—	Indenture dated as of April 11, 2006, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee with regard to Transcontinental Gas Pipe Line's $200 million aggregate principal amount of 6.4% Senior Note due 2016 (filed on April 11, 2006 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K) and incorporated herein by reference.
4.25	—	Indenture dated May 22, 2008, between Transcontinental Gas Pipe Line Corporation and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K) and incorporated herein by reference.
4.26	—	Indenture dated June 20, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and JPMorgan Chase Bank, N.A. (filed on June 20, 2006 as Exhibit 4.1 to Williams Partners L.P. Form 8-K) and incorporated herein by reference.
4.27	—	Indenture dated December 13, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and The Bank of New York (filed on December 19, 2006 as Exhibit 4.1 to Williams Partners L.P. Form 8-K) and incorporated herein by reference.
4.28	—	Indenture dated as of February 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 10, 2010 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.1	—	The Williams Companies Amended and Restated Retirement Restoration Plan effective January 1, 2008 (filed on February 25, 2009 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.2	—	The Williams Companies, Inc. 1996 Stock Plan (filed on March 27, 1996 as Exhibit A to The Williams Companies, Inc.'s Proxy Statement) and incorporated herein by reference.
10.3	—	The Williams Companies, Inc. 1996 Stock Plan for Non-employee Directors (filed on March 27, 1996 as Exhibit B to The Williams Companies, Inc.'s Proxy Statement) and incorporated herein by reference.
10.4	—	Form of Director and Officer Indemnification Agreement (filed on September 24, 2008 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.5*	—	Form of 2011 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers.
10.6*	—	Form of 2011 Restricted Stock Unit Agreement among Williams and certain employees and officers.
10.7*	—	Form of 2011 Nonqualified Stock Option Agreement among Williams and certain employees and officers.
10.8*	—	Form of 2010 Restricted Stock Unit Agreement among Williams and non-management directors.

Exhibit No.		Description
10.9	—	The Williams Companies, Inc. 2002 Incentive Plan as amended and restated effective as of January 23, 2004 (filed on August 5, 2004 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
10.10	—	Amendment No. 1 to The Williams Companies, Inc. 2002 Incentive Plan (filed on February 25, 2009 as Exhibit 10.11 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.11	—	Amendment No. 2 to The Williams Companies, Inc. 2002 Incentive Plan (filed on February 25, 2009 as Exhibit 10.12 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.12	—	The Williams Companies, Inc. 2007 Incentive Plan (filed on April 8, 2010 as Appendix B to The Williams Companies, Inc.'s Definitive Proxy Statement 14A) and incorporated herein by reference.
10.13	—	The Williams Companies, Inc. Employee Stock Purchase Plan (filed on April 10, 2007 as Appendix D to The Williams Companies, Inc.'s Definitive Proxy Statement 14A) and incorporated herein by reference.
10.14	—	Amendment No. 1 to The Williams Companies, Inc. Employee Stock Purchase (filed on February 25, 2009 as Exhibit 10.16 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference Plan.
10.15	—	Amendment No. 2 to The Williams Companies, Inc. Employee Stock Purchase Plan (filed on February 25, 2009 as Exhibit 10.17 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.16	—	Amendment No. 3 to The Williams Companies, Inc. Employee Stock Purchase Plan (filed on February 25, 2010 as Exhibit 10.17 the The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.17	—	Amendment No. 4 to The Williams Companies, Inc. Employee Stock Purchase Plan (filed on February 25, 2010 as Exhibit 10.17 the The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.18	—	Amended and Restated Change-in-Control Severance Agreement between the Company and certain executive officers (filed on February 25, 2009 as Exhibit 10.18 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.19	—	Amendment Agreement, dated May 9, 2007, among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed on October 28, 2010as Exhibit 10.1 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
10.20	—	Amendment Agreement dated November 21, 2007 among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline GP, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed on November 28, 2007 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.21	—	Credit Agreement dated as of May 1, 2006, among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and Williams Partners L.P., as Borrowers and Citibank, N.A., as Administrative Agent (filed on October 28, 2010 as Exhibit 10.2 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
10.22	—	Credit Agreement dated February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners (filed on October 28, 2010 as Exhibit 10.3 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.

Exhibit No.		Description
10.23	—	First Amendment dated as of March 30, 2007 to Credit Agreement dated as of February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners (filed on October 28, 2010 as Exhibit 10.4 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
10.24*	—	Second Amendment dated as of June 10, 2008 to Credit Agreement dated as of February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners (filed on October 28, 2010 as Exhibit 10.4 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
10.25*	—	Third Amendment dated as of July 12, 2010 to Credit Agreement dated as of February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners (filed on October 28, 2010 as Exhibit 10.4 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
10.26	—	Contribution Agreement, dated as of January 15, 2010, by and among Williams Energy Services, LLC, Williams Gas Pipeline Company, LLC, WGP Gulfstream Pipeline Company, L.L.C., Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and, for a limited purpose, The Williams Companies, Inc, including exhibits thereto (filed on January 19, 2010 as Exhibit 10.1 to The Williams Companies Inc.'s Form 8-K) and incorporated herein by reference.
10.27	—	Credit Agreement, dated as of February 17, 2010, by and among Williams Partners L.P., Transcontinental Gas Pipe Line Company, LLC, Northwest Pipeline GP, the lenders party thereto and Citibank, N.A., as Administrative Agent (filed on July 29, 2010 as Exhibit 10.1 to Williams Partners L.P.'s current report on Form 10-Q) and incorporated herein by reference.
12*	—	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.
14	—	Code of Ethics for Senior Officers (filed on March 15, 2004 as Exhibit 14 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
21*	—	Subsidiaries of the registrant.
23.1*	—	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
23.2*	—	Consent of Independent Registered Public Accounting Firm, Deloitte & Touche LLP.
23.3*	—	Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
23.4*	—	Consent of Independent Petroleum Engineers and Geologists, Miller and Lents, LTD.
24*	—	Power of Attorney.
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.
99.1*	—	Report of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
99.2*	—	Report of Independent Petroleum Engineers and Geologists, Miller and Lents, LTD.
101.INS**	—	XBRL Instance Document

Exhibit No.		Description
101.SCH**	—	XBRL Taxonomy Extension Schema
101.CAL**	—	XBRL Taxonomy Extension Calculation Linkbase
101.DEF**	—	XBRL Taxonomy Extension Definition Linkbase
101.LAB**	—	XBRL Taxonomy Extension Label Linkbase
101.PRE**	—	XBRL Taxonomy Extension Presentation Linkbase

* Filed herewith

** Furnished herewith

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/ TED T. TIMMERMANS
Ted T. Timmermans
Controller

Date: February 24, 2011

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/ ALAN S. ARMSTRONG Alan S. Armstrong	President, Chief Executive Officer and Director (Principal Executive Officer)	February 24, 2011
/s/ DONALD R. CHAPPEL Donald R. Chappel	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2011
/s/ TED T. TIMMERMANS Ted T. Timmermans	Controller (Principal Accounting Officer)	February 24, 2011
/s/ JOSEPH R. CLEVELAND* Joseph R. Cleveland*	Director	February 24, 2011
/s/ KATHLEEN B. COOPER* Kathleen B. Cooper*	Director	February 24, 2011
/s/ IRL F. ENGELHARDT* Irl F. Engelhardt*	Director	February 24, 2011
/s/ WILLIAM R. GRANBERRY* William R. Granberry*	Director	February 24, 2011
/s/ WILLIAM E. GREEN* William E. Green*	Director	February 24, 2011
/s/ JUANITA H. HINSHAW* Juanita H. Hinshaw*	Director	February 24, 2011
/s/ W.R. HOWELL* W.R. Howell*	Director	February 24, 2011

Signature	**Title**	**Date**
/s/ George A. Lorch* George A. Lorch*	Director	February 24, 2011
/s/ William G. Lowrie* William G. Lowrie*	Director	February 24, 2011
/s/ Frank T. MacInnis* Frank T. MacInnis*	Chairman of the Board	February 24, 2011
/s/ Janice D. Stoney* Janice D. Stoney*	Director	February 24, 2011
/s/ Laura A. Sugg* Laura A. Sugg*	Director	February 24, 2011
*By: /s/ La Fleur C. Browne La Fleur C. Browne *Attorney-in-Fact*		February 24, 2011

Corporate Data

ANNUAL MEETING
Stockholders are invited to our annual meeting at 11 a.m. Central Time on May 19, 2011, in the presentation theater, Williams Resource Center, One Williams Center, Tulsa, Okla.

INTERNET
Company information is available at www.williams.com.

INQUIRIES
To request additional materials, call 800-600-3782 or access our Web site.

Our investor relations group is available to answer questions about Williams. Call Sharna Reingold or David Sullivan at 918-573-2078 or 918-573-9360, respectively, or 800-600-3782. Direct your written inquiries to investor relations at our headquarters address below.

CORPORATE HEADQUARTERS
One Williams Center
Tulsa, OK 74172
Phone: 918-573-2000 or
toll-free, 800-WILLIAMS

WASHINGTON OFFICE
1627 Eye Street, N.W., Suite 900
Washington, D.C. 20006

TRANSFER AGENT AND REGISTRAR
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
Phone: 781-575-4706 or
toll-free, 800-884-4225
Hearing impaired: 800-952-9245
Internet: www.computershare.com

Send overnight mail to:
Computershare Trust Company, N.A.
250 Royall St.
Canton, MA 02021
Phone: 781-575-4706

Contact our transfer agent for information on registered share accounts, dividend payments or to receive information on our Direct Stock Purchase Plan.

AUDITORS
Ernst & Young LLP
Box 1529
Tulsa, OK 74101

CERTIFICATIONS
We submitted the certification of Steven J. Malcolm, our former Chairman of the Board, Chief Executive Officer and President, to the New York Stock Exchange pursuant to NYSE Section 303A.12(a) on June 17, 2010.

We also filed with the Securities and Exchange Commission on February 24, 2011, as Exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the year ended December 31, 2010, the certificates of our Chief Executive Officer and Chief Financial Officer as required by Section 302 of the Sarbanes-Oxley Act of 2002.

EQUAL OPPORTUNITY
The Company is an Equal Employment Opportunity (EEO) employer and does not discriminate in any employer/employee relations based on race, color, religion, sex, sexual orientation, national origin, age, disability or veteran's status.

CORPORATE RESPONSIBILITY
To view Williams' corporate responsibility report, go to www.williams.com.

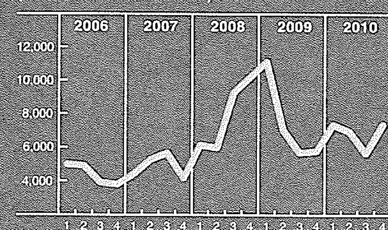
Stockholder Information

WILLIAMS SECURITIES
Williams common stock (WMB) is listed on the New York Stock Exchange.

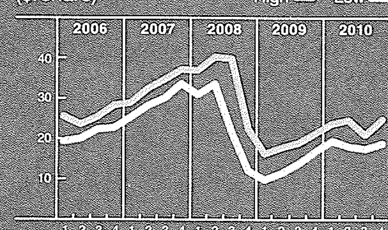
The market value on Feb. 18, 2011, was approximately $17.8 billion. On that date, 10,032 shareholders of record held 586,207,919 shares of Williams common stock. The company's common stock in 2010 traded at an average daily volume of 6.8 million shares.

WILLIAMS COMMON STOCK ACTIVITY
A dividend of eleven cents per share was paid in all four quarters of 2009. A dividend of eleven cents was paid in the first quarter of 2010 and a dividend of twelve and one-half cents was paid the remaining three quarters of 2010.

WMB AVERAGE DAILY VOLUMES TRADED
(thousands of shares)



WMB PRICE RANGES
($/share) High Low



WILLIAMS DAILY PRICES
($/share)

	2010		2009	
	High	Low	High	Low
1st Quarter	23.76	19.51	16.87	9.52
2nd Quarter	24.66	18.16	17.99	11.30
3rd Quarter	21.00	17.53	19.21	13.59
4th Quarter	24.89	18.88	21.54	16.57

(800) WILLIAMS I www.williams.com I

Ingenuity takes energy.®

Williams®

SUSTAINABLE FORESTRY INITIATIVE

Certified Fiber Sourcing

www.sfiprogram.org