2012 Annual Report

The Williams Companies, Inc.

We make energy happen.℠

Williams.

Financial Highlights

Dollars in millions, except per-share amounts

	2012	2011	2010	2009	2008
Revenues	**$7,486**	$7,930	$6,638	$ 5,278	$6,904
Income (loss) from continuing operations[1]	**929**	1,078	271	346	682
Amounts attributable to The Williams Companies, Inc.:					
Income (loss) from continuing operations	**723**	803	104	206	528
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	**1.15**	1.34	0.17	0.35	0.90
Total assets at December 31[2,3]	**24,327**	16,502	24,972	25,280	26,006
Short-term notes payable and long-term debt due within one year at December 31	**1**	353	508	17	18
Long-term debt at December 31[3]	**10,735**	8,369	8,600	8,259	7,683
Stockholders' equity at December 31[2,3]	**4,752**	1,296	6,803	7,990	7,983
Cash dividends declared per common share	**1.196**	0.775	0.485	0.44	0.43

[1] Income from continuing operations for 2011 includes $271 million of pre-tax early debt retirement costs and 2010 includes $648 million of pre-tax costs associated with our strategic restructuring transaction in the first quarter of 2010. See Note 5 of Notes to Consolidated Financial Statements for further discussion of asset sales and other accruals in 2012, 2011 and 2010.

[2] Total assets and stockholders' equity for 2011 decreased due to the special dividend to spin off our former exploration and production business.

[3] The increases in 2012 reflect assets and investments acquired, primarily related to the Caiman and Laser Acquisitions and our investment in Access Midstream Partners, as well as debt and equity issuances.

On the Cover: Williams' Fort Beeler gas processing facility in Marshall County, W. Va. is expanding to meet the growing needs of natural gas producers in the Northeast U.S.

***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 25 of the Form 10-K in the back of this report.*

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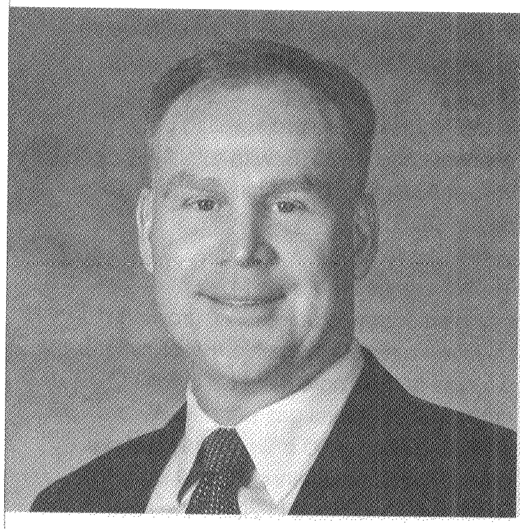

President and Chief Executive Officer
Alan Armstrong

Dear fellow Williams shareholders,

Williams took major steps in 2012 toward our goal of becoming North America's premier provider of energy infrastructure. During the past year, we announced new expansion projects and completed others; increased our competitive footprint through acquisitions in the Northeast and a major investment; completed a strategic reorganization of the company; and delivered solid financial results in the face of declining natural-gas liquids margins.

From a business perspective, our course remained steady. We continued to make substantial capital investments to take full advantage of the extraordinary opportunities presented by the North American energy supercycle, spurred by the emergence of shale gas. One would have to go back decades to find a time when so much new infrastructure was required to accommodate the tremendous demand for domestic energy. We believe that Williams has the right combination of people and assets to thrive in this environment.

We are investing heavily in the most prolific, fastest growing basins. In fact, we're directing about half of our capital expenditures to growth projects in the Marcellus and Utica shales in the northeastern United States. It's important to understand that we're investing significant dollars — and significant periods of time for planning, permitting and construction — before these projects begin generating revenues. This growth strategically positions us to be among the top providers of gathering, processing and transmission services in those markets for many years to come. As our strategy has proven many times before, these positions will allow us to generate sustainable, above-market returns.

We continue to make significant progress in moving our revenue mix to greater reliance on fee-based business and diminishing our exposure to commodity-price volatility. In 2014, we expect to have grown our fee-based revenues to nearly $4 billion, up more than 50 percent from fee-based revenues in 2011. The oversupply of natural gas liquids is creating price volatility, so that the margins from which we have benefited in past years are no longer as predictable. Our focus on investing in fee-based businesses helps further inoculate us from those price

"We continued to make substantial capital investments to take full advantage of the extraordinary opportunities presented by the North American energy supercycle, spurred by the emergence of shale gas."

swings. In fact, we expect fee-based revenues will represent about 74 percent of our revenues by 2014.

Beyond those capital investments, we made a major investment in December last year that we expect to become a very important contributor to continued growth in our earnings, cash flows and dividends in 2015 and beyond. We acquired a 50 percent interest, including incentive-distribution rights, in Access Midstream Partners GP, LLC, and approximately 24 percent of the limited partner units of Access Midstream Partners, LP (NYSE: ACMP). This transaction significantly expands our exposure in the Marcellus and Utica basins. It also provides large-scale, strategy-consistent positions that expand our exposure to prolific basins that have been attractive targets for us. For 2013 and 2014, we forecast that Williams will receive distributions from this investment of $92 million and $133 million, respectively. Beyond 2014, we expect that growth to accelerate.

We continue to see incredible opportunity in supplying feedstock to the U.S. petrochemical industry. As that industry experiences a renaissance, we are uniquely positioned to provide the products and services necessary to enable the success of our petchem customers. That's why we are investing in numerous projects, especially in the Gulf of Mexico region. We are expanding our Geismar, La., olefins facility; we purchased several strategically located liquids pipelines serving the Houston Ship Channel; and we are pursuing joint development of a major NGL pipeline with Boardwalk Pipeline Partners.

That proposed pipeline, known as the Bluegrass Pipeline, is intended to connect Marcellus and Utica producers' NGLs to the Gulf Coast petchem and export facilities, as well as the developing petchem complex in the Northeast U.S. By using a mix of existing and new facilities, Bluegrass Pipeline would have an in-service date of late 2015. That timing is critical, since existing NGL systems in the Northeast are projected to be overwhelmed by 2016, with total NGL volumes topping 1.2 million barrels per day by 2020.

The Bluegrass Pipeline will be complementary to our strong, growing midstream assets in the Northeast, where we now gather more than 1.5 billion cubic feet of natural gas per day. We are gathering about 900 million cubic feet per day on the Susquehanna Supply Hub, which we announced in 2011. We have grown gathering volumes by 80 percent each in the Susquehanna Supply Hub in northeast Pennsylvania and our Laurel Mountain franchise in the southwestern part of the state.

As with NGLs and gathering capacity, interstate pipeline constraints also are slowing down shale gas development in the Northeast. To alleviate these bottlenecks, we continue to work on expanding our natural gas transportation capacity in the region. One of those projects, Constitution Pipeline, is a venture with Cabot Oil & Gas and Piedmont Natural Gas. Constitution will connect abundant Appalachian natural gas supplies in northern Pennsylvania with major northeastern markets by 2015. And that's just one of the many interstate gas pipeline expansions we're pursuing in the Northeast, where our Transco pipeline has operated for decades, serving New York City and other major markets.

To be sure, the energy supercycle is driving change in our industry. It also is driving change within our organization. At the beginning of 2013, we completed a major reorganization of our company in an effort to move from a holding-company design to a more-focused, operating-company mentality. We designed our new organization to maximize our capital investments by transferring knowledge from established operating areas to new basins and keeping our management focus on best-in-class development and execution of projects and operational excellence. We believe we have built the right organization to ensure that every employee, at every level, is committed to actions that best serve our customers and create value for shareholders.

On that note, we are pleased to continue increasing our cash dividends for shareholders. We have reaffirmed our annual dividend growth in each 2013 and 2014 of 20 percent — the best growth in our industry. This dividend growth is evidence of our long-term, value-creation strategy and our commitment to shareholders.

This upward trajectory of our dividends speaks to the confidence we have in our business strategy and in our investments. We certainly have our challenges, as a company and as an industry, in delivering on the tremendous opportunities in front of us. We firmly believe we will meet those challenges head on and push through to a new domestic energy economy that benefits everyone — investors, customers and consumers.

Getting there will take decisive leadership. For our part, we believe Williams is providing that leadership, as much through our actions as our words. We are investing in people. We are investing in technology. We are investing in infrastructure. And, most of all, we are investing in a future of renewed prosperity and energy security for North America.

Alan S. Armstrong
President and Chief Executive Officer

April 4, 2013

"We believe we have built the right organization to ensure that every employee, at every level, is committed to actions that best serve our customers and create value for shareholders."

DIRECTORS

ALAN S. ARMSTRONG, 50
Tulsa, Okla.
Director, President and
Chief Executive Officer, Williams.
Director since 2011.

JOSEPH R. CLEVELAND, 68
Windermere, Fla.
Former Chief Information Officer,
Lockheed Martin Corporation.
Director since 2008.

KATHLEEN B. COOPER, 68
Dallas, Texas
Senior Fellow, Tower Center for Political
Studies, Southern Methodist University.
Director since 2006.

JOHN A. HAGG, 65
Calgary, Alberta, Canada
Chairman, Strad Energy Services Ltd.
Director since 2012.

JUANITA H. HINSHAW, 68
St. Louis, Mo.
President and Chief Executive
Officer, H&H Advisors.
Director since 2004.

RALPH IZZO, 55
Newark, N.J.
Chairman, Chief Executive Officer and
President, Public Service Enterprise
Group, Inc.
Director since 2013.

FRANK T. MACINNIS, 66
Norwalk, Conn.
Chairman of the Board, Williams.
Director since 1998.

STEVEN W. NANCE, 56
The Woodlands, Texas
President and Manager,
Steele Creek Energy, LLC.
Director since 2012.

MURRAY D. SMITH, 63
Calgary, Alberta, Canada
President, Murray Smith
and Associates; former Minister
of Energy for Alberta, Canada.
Director since 2012.

JANICE D. STONEY, 72
Phoenix, Ariz.
Former Executive Vice President,
U S WEST Communications Group, Inc.
Director since 1999.

LAURA A. SUGG, 52
Katy, Texas
Former President,
Conoco Phillips Australasia Division.
Director since 2010.

HONORARY DIRECTORS

JOHN H. WILLIAMS, 94
Tulsa, Okla.
President and Chief Executive Officer
for Williams from 1949-71; Chairman and
Chief Executive Officer from 1971-79.
Elected to the board in 1949.

JOSEPH H. WILLIAMS, 79
Charleston, S.C.
Chairman and Chief Executive
Officer for Williams from 1979-94.
Elected to the board in 1969.

SENIOR OFFICERS

ALAN S. ARMSTRONG
Director, President and
Chief Executive Officer

FRANK E. BILLINGS
Senior Vice President,
Northeast G&P

ALLISON G. BRIDGES
Senior Vice President,
West

DONALD R. CHAPPEL
Senior Vice President and
Chief Financial Officer

ROBYN L. EWING
Senior Vice President and
Chief Administrative Officer

RORY L. MILLER
Senior Vice President,
Atlantic - Gulf

RANDY M. NEWCOMER
Interim Senior Vice President,
NGL & Petchem Services

FRED E. PACE
Senior Vice President,
E&C

BRIAN L. PERILLOUX
Senior Vice President,
Operational Excellence

CRAIG L. RAINEY
Senior Vice President
and General Counsel

JAMES E. SCHEEL
Senior Vice President,
Corporate Strategic Development

BOARD COMMITTEES

Audit Committee

Joseph R. Cleveland

Kathleen B. Cooper (Chair)

John A. Hagg

Juanita H. Hinshaw

Compensation Committee

Frank T. MacInnis

Steven W. Nance

Murray D. Smith

Janice D. Stoney (Chair)

Laura A. Sugg

Finance Committee

Joseph R. Cleveland

Kathleen B. Cooper

John A. Hagg

Juanita H. Hinshaw (Chair)

Laura A. Sugg

Nominating & Governance Committee

Frank T. MacInnis (Chair)

Steven W. Nance

Murray D. Smith

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, 2012

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 $18,031,364,160.

The number of shares outstanding of the registrant's common stock outstanding at February 21, 2013 was 681,532,705.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Definitive Proxy Statement for the Registrant's Annual Meeting of Stockholders to be held on May 16, 2013, 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: One barrel of petroleum products that equals 42 U.S. gallons.

Bcf : One billion cubic feet of natural gas.

Bcf/d: One bcf of natural gas per day.

British Thermal Unit (Btu): A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

Dekatherms (Dth): A unit of energy equal to one million Btus.

Mbbls/d: One thousand barrels per day.

Mdth/d: One thousand dekatherms per day.

MMcf/d: One million cubic feet per day.

MMdth: One million dekatherms or approximately one trillion Btus.

MMdth/d: One million dekatherms per day.

TBtu: One trillion Btus.

Other definitions:

FERC: Federal Energy Regulatory Commission.

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

LNG: Liquefied natural gas; natural gas which has been liquefied at cryogenic temperatures.

NGL: 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: NGL revenues less Btu replacement cost, plant fuel, transportation, and fractionation.

Partially Owned Entities: Entities in which we do not own a 100 percent ownership interest and which we account for as an equity investment, including principally Access Midstream Partners, L.P., Access Midstream Ventures, L.L.C., Caiman Energy II, LLC, Discovery Producer Services LLC, Gulfstream Natural Gas System, L.L.C., Laurel Mountain Midstream, LLC, Aux Sable Liquid Products L.P., and Overland Pass Pipeline Company LLC.

Throughput: 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 www.sec.gov.

Our Internet website is 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 energy infrastructure company focused on connecting North America's significant hydrocarbon resource plays to growing markets for natural gas, NGLs, and olefins. Our operations are located principally in the United States, but span from the deepwater Gulf of Mexico to the Canadian oil sands.

Our interstate gas pipeline, domestic midstream, and domestic olefins production interests are largely held through our significant investment in Williams Partners L.P. (WPZ), one of the largest energy master limited partnerships. We own the general partner interest and a 68 percent limited-partner interest in WPZ. We also own a Canadian midstream business, which processes oil sands offgas and produces olefins for petrochemical feedstocks, as well as a significant equity investment in Access Midstream Partners, which owns midstream assets in major unconventional producing areas.

We were founded in 1908, originally incorporated under the laws of the state of Nevada in 1949 and reincorporated under the laws of the state of Delaware in 1987. Williams' headquarters are located in Tulsa, Oklahoma, with other major offices in Salt Lake City, Houston, the Four Corners Area and Pennsylvania. Our telephone number is 918-573-2000.

ORGANIZATIONAL RESTRUCTURING

Following the spin-off of WPX Energy, Inc. (WPX) at the end of 2011 and in consideration of our growth plans, we initiated an organizational restructuring evaluation to better align resources to support an ongoing business strategy to provide large-scale energy infrastructure designed to maximize the opportunities created by the vast supply of natural gas, natural gas products, and crude oil that exists in North America. As a result of this evaluation, certain organizational changes were implemented January 1, 2013, that generally organize our businesses in geographically based operating areas and centralize certain operational support functions. This will have no impact on our segment presentation, including Williams Partners as it continues to be 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 (See Note 18 of Notes to Consolidated Financial Statements).

Information in this report has generally been prepared to be consistent with the reportable segment presentation in our consolidated financial statements in Part II, Item 8 of this document. Our reportable segment presentation will not change as a result of the restructuring. These segments are discussed in further detail in the following sections.

DIVIDEND GROWTH

We increased our quarterly dividends from $0.25 per share in the fourth quarter of 2011 to $0.325 per share in the fourth quarter of 2012. Also, consistent with our expectation of receiving increasing cash distributions from our interest in WPZ and Access Midstream Partners, we expect to increase our dividend on a quarterly basis. Our Board of Directors has approved a dividend of $0.33875 per share for the first quarter of 2013 and we expect total 2013 dividends to be $1.44 per share, which is approximately 20 percent higher than 2012. We expect 2014 dividends to be $1.75.

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. Our activities in 2012 were primarily operated through the following business segments:

- *Williams Partners* — comprised of our master limited partnership 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; an olefin production business and is comprised of several wholly owned and partially owned subsidiaries and joint venture investments.
- *Williams NGL & Petchem Services* (formerly referred to as *Midstream Canada & Olefins)* — primarily comprised of our Canadian midstream operations and certain of our recently acquired domestic olefins pipeline assets. Our Canadian operations include an oil sands offgas processing plant located near Fort McMurray, Alberta, and an NGL/olefin fractionation facility and butylenes/butane splitter (B/B splitter) facility, both of which are located at Redwater, Alberta, which is near Edmonton, Alberta.
- *Access Midstream Partners* — comprised of an indirect equity interest in Access Midstream Partners GP, L.L.C. (Access GP) and limited partner interests in Access Midstream Partners, L.P. (ACMP), which we purchased in the fourth quarter of 2012. ACMP is a publicly-traded master limited partnership that provides gathering, processing, treating and compression services to Chesapeake Energy Corporation and other producers under long-term, fee-based contracts. Access GP is the general partner of ACMP. (See Note 2 of Notes to Consolidated Financial Statements.)
- *Other* — primarily comprised of corporate operations.

This report is organized to reflect this structure. Detailed discussion of each of our business segments follows.

Williams Partners

Gas Pipeline Business

Williams Partners owns and operates a combined total of approximately 13,700 miles of pipelines with a total annual throughput of approximately 3,400 TBtu of natural gas and peak-day delivery capacity of approximately 14 MMdth 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 50 percent interest in Gulfstream Natural Gas System, LLC (Gulfstream) and a 51 percent interest in Constitution Pipeline Company, LLC (Constitution).

Transco

Transco is an interstate natural gas transmission company that owns and operates a 9,800-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, Delaware, Pennsylvania and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 12 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, 2012, Transco's system had a mainline delivery capacity of approximately 5.8 MMdth of natural gas per day from its production areas to its primary markets, including delivery capacity from the mainline to locations on its Mobile Bay Lateral. Using its Leidy Line along with market-area storage and transportation capacity, Transco can deliver an additional 4.0 MMdth of natural gas per day for a system-wide delivery capacity total of approximately 9.8 MMdth 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 we own and operate. 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 Bcf of natural gas. At December 31, 2012, our customers had stored in our facilities approximately 150 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, an LNG storage facility with 4 Bcf 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 2012 or are future significant pipeline projects for which Transco has customer commitments.

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. The capital cost of the project is estimated to be approximately $200 million. Transco placed the first phase of the project into service in September 2012, which increased capacity by 95 Mdth/d. Transco plans to place the second phase into service in June 2013, which is expected to increase capacity by an additional 130 Mdth/d.

Mid-Atlantic Connector

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. The capital cost of the project was approximately $60 million. The project was placed into service in the first quarter of 2013, increasing capacity by 142 Mdth/d.

Northeast Supply Link

In November 2012, Transco received approval from the FERC to expand its 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. The capital cost of the project is estimated to be approximately $390 million. Transco plans to place the project into service in November 2013, and it is expected to increase capacity by 250 Mdth/d.

Rockaway Delivery Lateral

In January 2013, Transco filed an application with the FERC for the construction of a three-mile offshore lateral to a distribution system in New York. The capital cost of the project is estimated to be approximately $180 million. Transco plans to place the project into service during the second half of 2014, with an expected capacity of 647 Mdth/d.

Virginia Southside

In December 2012, Transco filed an application with the FERC to expand Transco's existing natural gas transmission system from the Zone 6 Station 210 Pooling Point in New Jersey to Dominion Virginia Power's proposed power station in Brunswick County, Virginia, and our Cascade Creek interconnect with East Tennessee Natural Gas and our Pleasant Hill delivery point to Piedmont Natural Gas Company, Inc. in North Carolina. The capital cost of the project is estimated to be approximately $300 million. Transco plans to place the project into service in September 2015, and is expected to increase capacity by 270 Mdth/d.

Leidy Southeast

The Leidy Southeast Project involves an expansion of Transco's existing natural gas transmission system from the Marcellus Shale production region in Pennsylvania to a pooling point in Alabama. Transco anticipates filing an application with the FERC in the fourth quarter of 2013. The capital cost of the project is estimated to be approximately $600 million. Transco plans to place the project into service in December 2015, and it is expected to increase capacity by 469 Mdth/d.

Northwest Pipeline

Northwest Pipeline is an interstate natural gas transmission 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 Washington, Oregon, Idaho, Wyoming, Nevada, Utah, Colorado, New Mexico, California and Arizona directly or indirectly through interconnections with other pipelines.

Pipeline system and customers

At December 31, 2012, Northwest Pipeline's system, having long-term firm transportation agreements including peaking service of approximately 3.9 MMdth/d, 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 472,000 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 14.2 MMdth of natural gas, which is substantially utilized for third-party natural gas. These natural gas storage facilities enable Northwest Pipeline to balance daily receipts and deliveries and provide storage services to certain customers.

Northwest Pipeline expansion project

North and South Seattle Lateral Delivery Expansions

Northwest Pipeline has executed agreements with a customer to expand the North and South Seattle laterals and provide additional lateral capacity of approximately 80 Mdth/d and 74 Mdth/d, respectively. The total estimated cost of the project is between $32 and $36 million. We placed North Seattle into service in November 2012. South Seattle is currently targeted for service in fall 2013.

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 50 percent interest in Gulfstream. Spectra Energy Corporation, through its subsidiary, and Spectra Energy Partners, LP, own the other 50 percent interest. Williams Partners shares operating responsibilities for Gulfstream with Spectra Energy Corporation and accounts for this using the equity method as described in Note 1 of our Notes to Consolidated Financial Statements.

Constitution Pipeline

In April 2012, Williams Partners began the FERC pre-filing process for a new interstate gas pipeline project. We currently own 51 percent of Constitution Pipeline with two other parties holding 25 percent and 24 percent, respectively. Williams Partners will be the operator of Constitution Pipeline. The new 120-mile Constitution Pipeline will connect Williams Partners' gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems. The total cost of the entire project is estimated to be $680 million. Williams Partners plans to place the project into service in March 2015, with an expected capacity of 650 thousand dekatherms per day (Mdth/d). The pipeline is fully subscribed with two shippers. Williams Partners expects to file a FERC application during the second quarter of 2013.

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, Louisiana, Pennsylvania, West Virginia, New York, and Ohio. The primary businesses are: (1) natural gas gathering, treating, and processing; (2) NGL fractionation, storage and transportation; (3) oil transportation; and (4) olefins production. These 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;
- Producer drilling activities impacting natural gas supplies supporting our gathering and processing volumes;
- Prices impacting commodity-based activities.

Expansion Projects

The midstream projects listed below were completed during 2012 or are future significant projects.

Northeast

Ohio Valley

In April 2012, WPZ completed the acquisition of 100 percent of the ownership interest in Caiman Eastern Midstream, LLC (Caiman Acquisition). The acquisition provides us with a significant footprint and growth potential in the natural gas liquids-rich Ohio River Valley area of the Marcellus Shale. Several projects were completed in the fourth quarter of 2012 increasing our gathering, processing and fractionating capacities. The Fort Beeler plant complex has 320 MMcf/d of cryogenic processing capacity currently available. The Moundsville fractionator is now in service with approximately 13 Mbbls/d of NGL handling capacity. An NGL pipeline, connecting the Fort Beeler plant to the Moundsville fractionator has also been completed and is in service.

We also have expansions currently under construction to our natural gas gathering system, processing facilities and fractionator in our Ohio Valley Midstream business of the Marcellus Shale including a third turbo-expander at our Fort Beeler facility which is expected to add 200 MMcf/d of processing capacity in the first quarter of 2013. By the end of 2013, we expect our first turbo-expander at our Oak Grove facility to add 200 MMcf/d of processing capacity and additional fractionation capacity at our Moundsville fractionators bringing the NGL handling capacity to approximately 43 Mbbls/d.

Caiman II

In July 2012, WPZ formed Caiman Energy II, LLC with Caiman Energy, LLC and others to develop large-scale natural gas gathering and processing and the associated liquids infrastructure serving oil and gas producers in the Utica shale, primarily in Ohio and northwest Pennsylvania. As a result, through our 47.5 percent ownership, WPZ plans to contribute $380 million through 2014 to fund a portion of Blue Racer Midstream, a joint project formed in December 2012 between Caiman Energy II, LLC and another party.

Susquehanna Supply Hub

In February 2012, WPZ completed the acquisition of 100 percent of the ownership interests in certain entities from Delphi Midstream Partners, LLC (Laser Acquisition). The gathering system is comprised of 33 miles of 16-inch natural gas pipeline and associated gathering facilities in Susquehanna County, in northeastern Pennsylvania, as well as 10 miles of gathering pipeline in southern New York. The acquisition is supported by existing long-term gathering agreements that provide acreage dedications and volume commitments.

Our Springville pipeline, a 33-mile, 24-inch diameter natural gas gathering pipeline, connecting a portion of our gathering assets into the Transco pipeline, was placed into service in January 2012, and expansions were completed in the third quarter of 2012 allowing us to deliver approximately 625 MMcf/d into the Transco pipeline. This new take-away capacity allows full use of approximately 1.6 Bcf/d of capacity from various compression and dehydration expansion projects to our gathering business in northeastern Pennsylvania's Marcellus Shale which we acquired at the end of 2010.

As production in the Marcellus increases and expansion projects are completed, the Susquehanna Supply Hub is expected to reach a natural gas take away capacity of 3 Bcf/d by 2015, including capacity contributions from the Constitution Pipeline.

Laurel Mountain Midstream

In addition, we plan expansions to our gathering system infrastructure through capital to be invested within our Laurel Mountain equity investment, also in the Marcellus Shale region.

Atlantic-Gulf

Gulfstar FPS™ Deepwater Project

We will design, construct, and install our Gulfstar FPS™, a spar-based floating production system that utilizes a standard design approach with a capacity of 60 Mbbls/d of oil, up to 200 MMcf/d of natural gas, and the capability to provide seawater injection services. We expect Gulfstar FPS™ to be capable of serving as a central host facility for other deepwater prospects in the area. Construction is underway and the project is expected to be in service in 2014. In January 2013, WPZ agreed to sell a 49 percent ownership interest in its Gulfstar FPS™ project to a third party. The transaction is expected to close in second-quarter 2013, at which time we expect the third party will contribute $225 million to fund its proportionate share of the project costs, following with monthly capital contributions to fund its share of ongoing construction.

Keathley Canyon Connector™

Our equity investee which we operate, Discovery Producer Services LLC (Discovery), plans to construct, own, and operate a new 215-mile, 20-inch deepwater lateral pipeline from a third-party floating production facility located in the Keathley Canyon production area in the central deepwater Gulf of Mexico. Discovery has signed long-term agreements with anchor customers for natural gas gathering and processing services for production from the Keathley Canyon and Green Canyon areas. The Keathley Canyon Connector™ lateral will originate from a third-party floating production facility in the southeast portion of the Keathley Canyon area and will connect to Discovery's existing 30-inch offshore natural gas transmission system. The lateral pipeline is estimated to have the capacity to flow more than 400 MMcf/d and will accommodate the tie-in of other deepwater prospects. Pre-construction activities have begun; the pipeline is expected to be laid in 2013 and in service in mid-2014.

West

Parachute

In conjunction with a basin-wide agreement for all gathering and processing services provided by us to WPX in the Piceance basin, we plan to construct a 350 MMcf/d cryogenic natural gas processing plant. The Parachute TXP I plant is expected to be in service in 2014.

NGL & Petchem Services

Overland Pass Pipeline

Through our equity investment in Overland Pass Pipeline Company LLC, we are participating in the construction of a pipeline connection and capacity expansions, expected to be complete in early 2013, to increase the pipeline's capacity to the maximum of 255 Mbbls/d, to accommodate new volumes coming from the Bakken Shale in the Williston basin.

Geismar

With the benefit of a $350-$400 million expansion under way and scheduled for completion by late 2013, the facility's annual ethylene production capacity will grow by 600 million pounds to 1.95 billion pounds. Along with ethane, propane and ethylene, the Geismar facility also produces propylene, butadiene, and debutanized aromatic concentrate (DAC). The additional capacity will be wholly owned by us and is expected to increase our share of the Geismar production facility to over 88 percent.

In the fourth quarter of 2012, we also completed the construction of a pipeline which is capable of supplying 12 Mbbls/d of ethane to our Geismar olefins production facility from Discovery's Paradis fractionator.

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. Williams Partners' treating facilities remove water vapor, carbon dioxide, and other contaminants and collect condensate, but do not extract NGLs. Williams Partners' is generally paid a fee based on the volume of natural gas gathered and/or treated, generally measured in the Btu heating value.

In addition, natural gas contains various amounts of NGLs, which generally have a higher value when separated from the natural gas stream. Our processing plants extract the NGLs in addition to removing water vapor, carbon dioxide, and other contaminants. 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, isobutane and natural gasoline, primarily used by the refining industry as blending stocks for motor gasoline or as a petrochemical feedstock.

Our gas processing services generate revenues primarily from the following three types of contracts:

- Fee-based: We are paid a fee based on the volume of natural gas processed, generally measured in the Btu heating value. Our customers are entitled to the NGLs produced in connection with this type of processing agreement. Beginning in 2013, a portion of our fee-based processing revenues will include a share of the margins on the NGLs produced. For the year ended December 31, 2012, 63 percent of the NGL production volumes were under fee-based contracts.
- Keep-whole: Under keep-whole contracts, we (1) process natural gas produced by customers, (2) retain some or all of the extracted NGLs as compensation for our services, (3) replace the Btu content of the retained NGLs that were extracted during processing with natural gas purchases, also known as shrink replacement gas, and (4) deliver an equivalent Btu content of natural gas for customers at the plant outlet. NGLs we retain in connection with this type of processing agreement are referred to as our equity NGL production. Under these agreements, we have commodity price exposure on the difference between NGL and natural gas prices. For the year ended December 31, 2012, 34 percent of the NGL production volumes were under keep-whole contracts.
- Percent-of-Liquids: Under percent-of-liquids processing contracts, we (1) process natural gas produced by customers, (2) deliver to customers an agreed-upon percentage of the extracted NGLs, (3) retain a portion of the extracted NGLs as compensation for our services, and (4) deliver natural gas to customers at the plant outlet. Under this type of contract, we are not required to replace the Btu content of the retained NGLs that were extracted during processing, and are therefore only exposed to NGL price movements. NGLs we retain in connection with this type of processing agreement are also referred to as our equity NGL production. For the year ended December 31, 2012, 3 percent of the NGL production volumes were under percent-of-liquids contracts.

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.

Demand for new gas gathering and processing services is dependent on producers' drilling activities, which is impacted by the strength of the economy, natural gas prices, and the resulting demand for natural gas by manufacturing and industrial companies and consumers. 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 2012, Williams Partners' facilities gathered and processed gas for approximately 220 customers. Williams Partners' top six gathering and processing customers accounted for approximately 54 percent of our gathering and processing revenue.

Demand for our equity NGLs is affected by economic conditions and the resulting demand from industries using these commodities to produce petrochemical-based products such as plastics, carpets, packing materials and blending stocks for motor gasoline and the demand from consumers using these commodities for heating and fuel. NGL products are currently the preferred feedstock for ethylene and propylene production, which has been shifting away from the more expensive crude-based feedstocks.

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. Our San Juan basin, southwest Wyoming and Piceance systems are capable of delivering residue gas volumes into Northwest Pipeline's interstate system in addition to third-party interstate systems. Our gathering system in Pennsylvania delivers residue gas volumes into Transco's pipeline in addition to third-party interstate systems.

Williams Partners owns and operates gas gathering, processing and treating assets within the states of Wyoming, Colorado, New Mexico, Pennsylvania, and West Virginia. We also own and operate gas gathering and processing assets and pipelines primarily within the onshore, offshore shelf, and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi, and Alabama.

The following table summarizes our significant operated natural gas gathering assets as of December 31, 2012:

	Natural Gas Gathering Assets				
	Location	**Pipeline Miles**	**Inlet Capacity (Bcf/d)**	**Ownership Interest**	**Supply Basins**
West					
Rocky Mountain	Wyoming	3,587	1.1	100%	Wamsutter & SW Wyoming
Four Corners	Colorado & New Mexico	3,823	1.8	100%	San Juan
Piceance	Colorado	328	1.4	(2)	Piceance
Northeast					
Ohio Valley	West Virginia	101	0.8	100%	Appalachian
Pennsylvania & New York	Pennsylvania & New York	191	1.7	100%	Appalachian
Laurel Mountain (1)	Pennsylvania	2,013	0.6	51%	Appalachian
Atlantic-Gulf					
Canyon Chief & Blind Faith	Deepwater Gulf of Mexico	139	0.5	100%	Eastern Gulf of Mexico
Seahawk	Deepwater Gulf of Mexico	115	0.4	100%	Western Gulf of Mexico
Perdido Norte	Deepwater Gulf of Mexico	105	0.3	100%	Western Gulf of Mexico
Offshore shelf & other	Gulf of Mexico	46	0.2	100%	Eastern Gulf of Mexico
Offshore shelf & other	Gulf of Mexico	245	0.9	100%	Western Gulf of Mexico
Discovery (1)	Gulf of Mexico	358	0.6	60%	Central Gulf of Mexico

(1) Statistics reflect 100 percent of the assets from the jointly owned investments that we operate, however our financial statements report equity method income from these investments based on our equity ownership percentage.

(2) We own 60 percent of a gathering system in the Ryan Gulch area, which we operate, with 140 miles of pipeline and 200 MMcf/d of inlet capacity. We own and operate 100 percent of the balance of the piceance gathering system.

In addition we own and operate several natural gas treating facilities in New Mexico, Colorado, Texas and Louisiana which bring natural gas to specifications allowable by major interstate pipelines. At our Milagro treating 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.

The following table summarizes our significant operated natural gas processing facilities as of December 31, 2012:

	Natural Gas Processing Facilities				
	Location	Inlet Capacity (Bcf/d)	NGL Production Capacity (Mbbls/d)	Ownership Interest	Supply Basins
West					
Opal	Opal, WY	1.5	70	100%	SW Wyoming
Echo Springs	Echo Springs, WY	0.7	58	100%	Wamsutter
Ignacio	Ignacio, CO	0.5	23	100%	San Juan
Kutz	Bloomfield, NM	0.2	12	100%	San Juan
Willow Creek	Rio Blanco County, CO	0.5	30	100%	Piceance
Parachute	Garfield County, CO	1.4	7	(2)	Piceance
Northeast					
Fort Beeler	Marshall County, WV	0.3	37	100%	Appalachian
Atlantic-Gulf					
Markham	Markham, TX	0.5	45	100%	Western Gulf of Mexico
Mobile Bay	Coden, AL	0.7	30	100%	Eastern Gulf of Mexico
Discovery (1)	Larose, LA	0.6	32	60%	Central Gulf of Mexico

(1) Statistics reflect 100 percent of the assets from the jointly owned investments that we operate, however our financial statements report equity method income from these investments based on our equity ownership percentage.

(2) We own 60 percent of the Sagebrush plant, which we operate, with an inlet capacity of 35 MMcf/d and NGL handling capacity of less than 1 Mbbls/d. We own and operate 100 percent of the balance of the parachute plant complex.

Crude Oil Transportation and Production Handling Assets

In addition to our natural gas assets, we own and operate four deepwater crude oil pipelines and own production platforms serving the deepwater in the Gulf of Mexico. Our crude oil transportation revenues are typically volumetric-based fee arrangements. However, a portion of our marketing revenues are recognized from purchase and sale arrangements whereby the oil that we transport is purchased and sold as a function of the same index-based price. Our 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.

The following table summarizes our significant crude oil transportation pipelines as of December 31, 2012:

	Crude Oil Pipelines			
	Pipeline Miles	Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Mountaineer & Blind Faith	155	150	100%	Eastern Gulf of Mexico
BANJO	57	90	100%	Western Gulf of Mexico
Alpine	96	85	100%	Western Gulf of Mexico
Perdido Norte	74	150	100%	Western Gulf of Mexico

The following table summarizes our production handling platforms as of December 31, 2012:

	Production Handling Platforms			
	Gas Inlet Capacity (MMcf/d)	**Crude/NGL Handling Capacity (Mbbls/d)**	**Ownership Interest**	**Supply Basins**
Devils Tower	210	60	100%	Eastern Gulf of Mexico
Canyon Station	500	16	100%	Eastern Gulf of Mexico
Discovery Grand Isle 115 (1)	150	10	60%	Central Gulf of Mexico

(1) Statistics reflect 100 percent of the assets from the jointly owned investments that we operate, however our financial statements report equity method income from these investments based on our equity ownership percentage.

Gulf Olefins

In November 2012, we contributed to WPZ an 83.3 percent undivided interest and operatorship of the olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf region. Our olefins business also operates an ethylene storage hub at Mont Belvieu using leased third-party underground storage caverns.

Our olefins production facility has 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, these assets 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. In the fourth quarter of 2012, we placed a pipeline in service that has the capacity to supply 12 Mbbls/d of ethane from Discovery's Paradis fractionator to the Geismar plant.

Our refinery grade propylene splitter has 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 this asset is 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.

Marketing Services

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 our processing plants, and also markets NGLs on behalf of third-party NGL producers, including some of our fee-based processing customers, and the NGL volumes owned by 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, we may purchase products in the spot market for resale. Other than a long-term agreement to sell our equity NGLs transported on Overland Pass Pipeline to ONEOK Hydrocarbon L.P., the majority of sales are based on supply contracts of one year or less in duration. Sales to ONEOK Hydrocarbon L.P., accounted for 14 percent, 17 percent, and 15 percent of our consolidated revenues in 2012, 2011, and 2010, respectively.

In certain situations to facilitate our gas gathering and processing activities, we buy natural gas from our producer customers for resale.

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

Other NGL & Petchem Operations

We own interests in and/or operate 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. We also own approximately 20 million barrels of NGL storage capacity in central Kansas near Conway.

We own approximately 178 miles of pipelines in the Houston Ship Channel area which transport a variety of products including ethane, propane, ammonia, tertiary butyl alcohol and other industrial products used in the petrochemical industry. We also own a tunnel crossing pipeline under the Houston Ship Channel which contains multiple pipelines which are leased to third parties.

We also own a 14.6 percent equity interest in Aux Sable Liquid Products L.P. (Aux Sable) 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 102 Mbbls/d of extracted liquids into NGL products. Additionally, in June 2011, Aux Sable acquired an 80 MMcf/d gas conditioning plant and a 12-inch, 83-mile gas pipeline infrastructure in North Dakota that provides additional NGLs to Channahon from the Bakken Shale in the Williston basin.

Operated Equity Investments

Discovery

We own a 60 percent equity interest in and operate 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

We own 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 2,000 miles of pipeline with a capacity of approximately 630 MMcf/d. Laurel Mountain has a long-term, dedicated, volumetric-based fee agreement, with some exposure to natural gas prices, to gather the anchor customer's production in the western Pennsylvania area of the Marcellus Shale. Construction is ongoing for numerous new pipeline segments and compressor stations, the largest of which is our Shamrock compressor station.

Overland Pass Pipeline

We operate and own a 50 percent ownership interest in Overland Pass Pipeline Company LLC (OPPL). OPPL includes a 760-mile NGL pipeline from Opal, Wyoming, to the Mid-Continent NGL market center near Conway, Kansas, along with 150- and 125-mile extensions into the Piceance and Denver-Julesberg 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 transportation agreement. We are constructing a pipeline connection and capacity expansions expected to be complete in early 2013, to increase the pipeline's capacity to the maximum of 255 Mbbls/d, to accommodate new volumes coming from the Bakken Shale in the Williston basin.

Operating Statistics

The following table summarizes our significant operating statistics for Williams Partners' midstream business:

	2012	2011	2010
Volumes: (1)			
Gathering (Tbtu)	1,616	1,377	1,262
Plant inlet natural gas (Tbtu)	1,638	1,592	1,599
NGL production (Mbbls/d) (2)	206	189	178
NGL equity sales (Mbbls/d) (2)	77	77	80
Crude oil transportation (Mbbls/d) (2)	126	105	94
Geismar ethylene sales (millions of pounds)	1,058	1,038	981

(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.

Williams NGL & Petchem Services

The Williams NGL & Petchem Services segment, formerly referred to as Midstream Canada & Olefins, consists primarily of our Canadian midstream business and certain domestic olefins pipeline assets.

Our Canadian operations include an oil sands offgas processing plant located near Fort McMurray, Alberta, and an NGL/olefin fractionation facility and butylene/butane splitter (B/B splitter) facility, both of which are located at Redwater, Alberta, which is near Edmonton, Alberta and the Boreal Pipeline which transports NGLs and olefins from our Fort McMurray plant to our Redwater fractionation facility. We operate the Fort McMurray area processing plant, while another party operates the Redwater facilities on our behalf. The B/B splitter was completed and placed into service in August 2010. Our Fort McMurray area facilities extract liquids from the offgas produced by a third-party oil sands bitumen upgrader. Our arrangement with the third-party upgrader is a "keep-whole" type where we remove a mix of NGLs and olefins from the offgas and return the equivalent heating value to the third-party upgrader in the form of natural gas, as well as a profit share where a portion above a threshold is shared with the third party. We extract, fractionate, treat, store, terminal and sell the propane, propylene, normal butane (butane), isobutane/butylene (butylene) and condensate recovered from this process. The commodity price exposure of this asset 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 offgas. Our extraction of liquids from upgrader offgas streams allows the upgraders to burn cleaner natural gas streams and reduces their overall air emissions.

The Fort McMurray extraction plant has processing capacity of 121 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 B/B splitter, which has a production capacity of 3.7 Mbbls/d of butylene and 3.7 Mbbls/d of butane, further fractionates the butylene/butane mix produced at our Redwater fractionators into separate butylene and butane products, which receive higher values and are in greater demand. We also purchase small volumes of olefin/NGLs mixes from third-party gas processors, fractionate the olefins and NGLs at our Redwater plant and sell the resulting products. The Boreal Pipeline was completed and placed into service in June 2012. The Boreal Pipeline is a 261-mile pipeline in Canada that transports recovered NGLs and olefins from our extraction plant in Fort McMurray to our Redwater fractionation facility. The pipeline has an initial capacity of 43 Mbbls/d that can be increased to an ultimate capacity of 125 Mbbls/d with additional pump stations. Our products are sold within Canada and the United States.

Expansion Projects

Construction began in the fourth quarter of 2011 on the ethane recovery project that will allow us to produce ethane/ethylene mix from our operations that process offgas from the Alberta oil sands. We are modifying our oil sands offgas extraction plant near Fort McMurray, Alberta, and constructing a de-ethanizer at our Redwater fractionation facility. Our de-ethanizer, which will have a production capacity of 17,000 bbls/d, will enable us to initially produce approximately 10,000 bbls/d of ethane/ethylene mix. We have signed a long-term contract to provide the ethane/ethylene mix to a third-party customer. We expect the project to be constructed using cash previously generated from Canadian and other international projects and we expect to complete the expansions and begin producing ethane/ethylene mix in mid-year 2013.

During the third quarter of 2012, we signed a long-term agreement to provide gas processing to a second bitumen upgrader in Canada's oils sands near Fort McMurray, Alberta. To support the new agreement, we plan to build a new liquids extraction plant, supporting facilities and an extension of the Boreal Pipeline to enable transportation of the NGL/olefins mixture to our Redwater facility. The NGL/olefins recovered are initially expected to be approximately 12,000 bbls/d by mid-2015, growing to approximately 15,000 bbls/d by 2018. The NGL/olefins mixture will be fractionated at our Redwater facilities into an ethane/ethylene mix, propane, polymer grade propylene, normal butane, an alkylation feed and condensate. To mitigate the ethane price risk associated with this deal, we have a long-term supply agreement with a third party customer. We expect to fund construction using cash from Canadian operations as well as international cash on-hand.

During the fourth quarter of 2012, we acquired 10 liquids pipelines in the Gulf Coast region. The acquired pipelines will be combined with an organic build-out of several projects to expand our petrochemical services in that region. The projects include the construction and commissioning of pipeline systems capable of transporting various products in the Gulf Coast region. The projects are expected to be placed into service beginning in late 2014.

Operating statistics

The following table summarizes our significant operating statistics:

	2012	2011	2010
Volumes:			
Canadian propylene sales (millions of pounds)	153	139	127
Canadian NGL sales (millions of gallons)	165	163	145

Access Midstream Partners

Our Access Midstream Partners segment consists of our recent investment in Access GP and ACMP. We now own a 50 percent interest in Access Midstream Ventures, L.L.C., which owns Access GP and its 2 percent general partner interest in ACMP and incentive distribution rights. In addition, we hold approximately 24 percent of ACMP's outstanding limited partnership units, for a combined ownership interest of approximately 25 percent of ACMP. Access Midstream Partners provides gathering, treating, and compression services to Chesapeake Energy Corporation and other leading producers under long-term, fee-based contracts. For the year ended December 31, 2012, ACMP's assets gathered approximately 2.8 Bcf of natural gas per day. ACMP's primary gathering systems consist of the following:

Barnett Shale

These assets consist of 25 interconnected gathering systems and 850 miles of pipeline. Average throughput for the year ended December 31, 2012, was 1.195 Bcf/d.

Eagle Ford Shale

These assets consist of 10 gathering systems and 624 miles of pipeline. Gross throughput for the year ended December 31, 2012, was just under 0.2 Bcf/d.

Haynesville Shale

The Springridge gathering system consists of 263 miles of pipeline. Average throughput for the year ended December 31, 2012, was 0.36 Bcf/d.

The Mansfield gathering system consists of 307 miles of pipeline. Average throughput for the year ended December 31, 2012, was 0.72 Bcf/d.

Marcellus Shale

ACMP operates and owns a 47 percent interest in a gathering system consisting of 10 gathering systems and 549 miles of pipeline. Average net throughput for the year ended December 31, 2012, was 0.7 Bcf/d. In addition to the partially owned systems, during December 2012, 622 miles of pipeline was acquired with an average throughput of 0.026 Bcf/d.

Niobrara Shale

This gathering system consists of two interconnected gathering systems and 105 miles of pipeline. Average throughput for the year ended December 31, 2012, was 0.013 Bcf/d.

Utica Shale

This gathering system consists of 371 miles of pipeline.

Mid-Continent

This gathering system consists of 2,584 miles of pipeline. Average throughput for the year ended December 31, 2012, was 0.56 Bcf/d.

Additional Business Segment Information

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

Operations related to certain assets in "Discontinued Operations" have been reclassified to "Discontinued Operations" in the accompanying financial statements and Notes to Consolidated 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, distributions and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, and, if needed, external financings, and net proceeds from asset sales. The terms of certain 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. Our interstate 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.

Revenues by service that exceeded 10 percent of consolidated revenue include:

	2012	2011	2010
		(Millions)	
Service:			
Regulated natural gas transportation and storage	1,609	1,569	1,506
Gathering & processing	1,100	948	840

REGULATORY MATTERS

Williams Partners

FERC

Williams Partners' gas pipeline 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. 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.

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. 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.

Williams Partners 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. In addition, Williams Partners owns a 50 percent interest in, and is the operator of OPPL, which is an interstate natural gas liquids pipeline regulated by the FERC pursuant to the Interstate Commerce Act. OPPL provides transportation service pursuant to tariffs filed with the FERC.

Pipeline Safety

Williams Partners' gas pipeline and midstream pipelines are subject to the Natural Gas Pipeline Safety Act of 1968, as amended, the Pipeline Safety Improvement Act of 2002, and the Pipeline Safety, Regulatory

Certainty, and Jobs Creation Act of 2011 (Pipeline Safety Act), which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. The U.S. Department of Transportation (USDOT) administers federal pipeline safety laws.

Federal pipeline safety laws authorize USDOT to establish minimum safety standards for pipeline facilities and persons engaged in the transportation of gas or hazardous liquids by pipeline. These safety standards apply to the design, construction, testing, operation, and maintenance of gas and hazardous liquids pipeline facilities affecting interstate or foreign commerce. USDOT has also established reporting requirements for operators of gas and hazardous liquid pipeline facilities, as well as provisions for establishing the qualification of pipeline personnel and requirements for managing the integrity of gas transmission and distribution lines and certain hazardous liquid pipelines. To ensure compliance with these provisions, USDOT performs pipeline safety inspections and has the authority to initiate enforcement actions.

Federal pipeline safety regulations contain an exemption that applies to gathering lines in certain rural locations. A substantial portion of our gathering lines qualify for that exemption and are currently not regulated under federal law. However, USDOT is completing a congressionally-mandated review of the adequacy of the existing federal and state regulations for gathering lines and has indicated that it may apply additional safety standards to rural gas gathering lines in the future.

States are preempted by federal law from regulating pipeline safety for interstate pipelines but most are certified by USDOT to assume responsibility for enforcing intrastate pipeline safety regulations and inspecting intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, they vary considerably in their authority and capacity to address pipeline safety. Our pipelines are designed, operated, and maintained to keep the facilities in compliance with state pipeline safety requirements.

On January 3, 2012, the Pipeline Safety Act was enacted. The Pipeline Safety Act requires USDOT to complete a number of reports in preparation for potential rulemakings. The issues addressed in these rulemaking provisions include, but are not limited to, the use of automatic or remotely-controlled shut-off valves on new or replaced transmission line facilities, modifying the requirements for pipeline leak detection systems, and expanding the scope of the pipeline integrity management requirements. USDOT is considering these and other provisions in the Pipeline Safety Act and has sought public comment on changes to the standards in its pipeline safety regulations.

Pipeline Integrity Regulations

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 completed assessment within required timeframe, with one exception which was reported to PHMSA. We estimate that the cost to complete the remediation associated with the 2012 assessments will be approximately $20 million, most of which we expect to be 2013 capital expenditures. 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.

State Gathering Regulation

Our onshore midstream gathering operations are subject to regulation by states in which we operate. Of the states where our 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.

OCSLA

Our offshore midstream gathering is subject to the Outer Continental Shelf Lands Act (OCSLA). 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."

Domestic Olefins

Williams Partners domestic olefins assets are regulated by the Louisiana Department of Environmental Quality, the Texas Railroad Commission, and various other state and federal entities regarding our liquids pipelines.

Williams NGL & Petchem Services

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 17 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, local 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:

- Leakage from gathering systems, underground gas storage caverns, pipelines, processing or treating facilities, transportation facilities and storage tanks;
- Damage to facilities resulting from accidents during normal operations;
- Damages to onshore and offshore equipment and facilities resulting from storm events or natural disasters;
- Blowouts, cratering and explosions.

In addition, we may be liable for environmental damage caused by former owners or operators of our properties.

We believe compliance with current environmental laws and regulations will not have a material adverse effect on our capital expenditures, earnings or current 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 additional information regarding the potential impact of federal, state, tribal or local regulatory measures on our business and specific environmental issues, please refer to "Risk Factors — *We are subject to risks associated with climate change and the regulation of greenhouse gas emissions,"* — *"Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs, liabilities and expenditures and could exceed current expectations,"* and — *Increased regulation of energy extraction activities, including hydraulic fracturing, could result in reductions or delays in drilling and completing new oil and natural gas wells, which could decrease the volume of natural gas and other products that we transport, gather, process and treat"* and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Environmental" and "Environmental Matters" in Note 17 of our Notes to Consolidated Financial Statements.

COMPETITION

Williams Partners

For Williams Partners' 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. More recently large reserves of shale gas have been discovered, in many cases much closer to major market centers. As a result, pipeline capacity is being used more efficiently and competition among pipeline suppliers to attach growing supply to market has increased.

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. The state plans have in some cases discouraged LDCs from signing long-term contracts for new capacity.

States have developed new plans that require utilities to encourage energy saving measures and diversify their energy supplies to include renewable sources. This has lowered the growth of residential gas demand. However, due to relatively low prices of natural gas, demand for electric power generation has increased.

These factors have increased the risk that customers will reduce their contractual commitments for pipeline capacity from traditional producing areas. Future utilization of pipeline capacity will depend on these factors and others impacting both U.S. and global demand for natural gas.

In Williams Partners' 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.

Ethylene and propylene markets, and therefore Williams Partners' olefins business, compete in a worldwide marketplace. Due to our NGL feedstock position at Geismar, we expect to 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. Accordingly, we believe that we are often not considered by such companies to be a direct competitor. We compete on the basis of service, price and availability of the products we produce.

Williams NGL & Petchem Services

Our Canadian midstream facilities continue to be the only NGL/olefins fractionator in western Canada and the only treater/processor of oil sands upgrader offgas. Our extraction of liquids from the upgrader offgas 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.

For additional information regarding competition for our services or otherwise affecting our business, please refer to "Risk Factors — *The long-term financial condition of our natural gas transportation and midstream businesses is dependent on the continued availability of natural gas supplies in the supply basins that we access, demand for those supplies in our traditional markets, and the prices of natural gas,*" "*— Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results,*" and "*— We may not be able to replace, extend, or add additional customer contracts or contracted volumes on favorable terms, if at all, which could affect our financial condition, the amount of cash available to pay dividends, and our ability to grow.*"

EMPLOYEES

At February 1, 2013, we had approximately 4,639 full-time employees.

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," "assumes," "guidance," "outlook,""in service date," 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;
- Cash flow from operations or results of operations;
- The levels of dividends to stockholders;
- Seasonality of certain business components; and
- Natural gas, natural gas liquids and olefins 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:

- Whether we have sufficient cash to enable us to pay current and expected levels of dividends;
- Availability of supplies, 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;
- Ability to acquire new businesses and assets and integrate those operations and assets into our existing businesses, as well as expand our facilities;
- Development of alternative energy sources;
- The impact of operational and development hazards;

- Costs of, changes in, or the results of laws, government regulations (including safety and environmental regulations), 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 and counterparties;
- 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;
- The amount of cash distributions from and capital requirements of our investments and joint ventures in which we participate;
- Risks associated with future weather conditions;
- Acts of terrorism, including cybersecurity threats and related disruptions; and
- 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.

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

Our revenues, operating results, future rate of growth and the value of certain components of our businesses depend primarily upon the prices of NGLs, olefins, 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, olefins, natural gas, oil 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, olefins, oil, petroleum, and related commodities;
- Turmoil in the Middle East and other producing regions;
- The activities of the Organization of Petroleum Exporting Countries;
- Terrorist attacks on production or transportation assets;
- Weather conditions;
- The level of consumer demand;
- The price and availability of other types of fuels or feedstocks;
- The availability of pipeline capacity;
- Supply disruptions, including plant outages and transportation disruptions;
- The price and quantity of foreign imports of natural gas and oil;
- 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; and
- The adoption of regulations or legislation relating to climate change and changes in natural gas production from exploration and production areas that we serve.

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

The development of the additional natural gas reserves that are essential for our natural gas transportation and midstream businesses to thrive requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to our pipeline systems. Low prices for natural gas, regulatory limitations, 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 and gathering 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 in which we have a limited or no presence, 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 systems 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.

We may not be able to grow or effectively manage our growth.

A principal focus of our strategy is to capitalize on growth opportunities. Our future growth will depend upon our ability to successfully identify, finance, acquire, integrate and operate projects and businesses. Failure to achieve any of these factors would adversely affect our ability to achieve growth.

We have recently completed, or are in the process of completing, significant growth acquisitions and construction projects and may engage in similar growth activities in the future to capture anticipated future demand for natural gas, NGL and olefins infrastructure. This demand may not ultimately materialize. As a result, our new or expanded facilities or businesses may not achieve profitability. In addition, the process of integrating newly acquired or constructed assets into our operations may result in unforeseen operating difficulties, may absorb significant management attention and may require financial resources that would otherwise be available for the ongoing development and expansion of our existing operations. Acquisitions or construction projects may require substantial new capital and could result in the incurrence of indebtedness, additional liabilities and excessive costs that could have a material adverse effect on our business, results of operations, financial condition and our ability to pay dividends to our stockholders. If we issue additional equity in connection with future growth activities, stockholders' ownership interest in us may be diluted and dividends we pay to our stockholders may be reduced. Further, any limitations on our access to capital, including limitations caused by illiquidity in the capital markets, may impair our ability to complete future acquisitions and construction projects on favorable terms, if at all.

Our acquisition attempts may not be successful or may result in completed acquisitions that do not perform as anticipated.

We have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- Some of the acquired businesses or properties may not produce revenues, earnings or cash flow at anticipated levels or could have environmental, permitting or other problems for which contractual protections prove inadequate;

- We may lose all or part of the value of our investment or be required to contribute additional capital to support businesses or properties acquired;
- We may assume liabilities that were not disclosed to us or that exceed our estimates;
- We may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and
- Acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures.

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.

Our growth may be dependent upon the construction of new natural gas gathering, transportation, compression, processing or treating pipelines and facilities, NGL fractionation or storage facilities or olefins processing 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; and
- 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.

We do not own all of the interests in the Partially Owned Entities, which could adversely affect our ability to operate and control these assets in a manner beneficial to us.

Because we do not control the Partially Owned Entities, we may have limited flexibility to control the operation of or cash distributions received from these entities. The Partially Owned Entities' organizational documents require distribution of their available cash to their members on a quarterly basis; however, in each case, available cash is reduced, in part, by reserves appropriate for operating the businesses. At December 31, 2012, our investments in the Partially Owned Entities accounted for approximately 16 percent of our total consolidated assets. We expect that conflicts of interest may arise in the future between us, on the one hand, and our Partially Owned Entities, on the other hand, with regard to our Partially Owned Entities' governance, business and operations. If a conflict of interest arises between us and a Partially Owned Entity, other owners may control the Partially Owned Entity's actions with respect to such matter (subject to certain limitations), which could be detrimental to our business. Any future disagreements with the other co-owners of these assets could adversely affect our ability to respond to changing economic or industry conditions, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Holders of our common stock may not receive dividends in the amount identified in guidance or any dividends at all.

We may not have sufficient cash flow each quarter to make dividends or maintain current or expected levels of dividends. The actual amount of cash we dividend will depend on the following factors, some of which are beyond our control, among others:

- The amount of cash that WPZ and our other subsidiaries and the Partially Owned Entities distribute to us;
- The amount of cash we generate from our operations, which is subject to prices we obtain for our services, the prices of natural gas, NGLs and olefins, and the volumes of gas we process and NGLs and olefins we fractionate and store, and our operating costs;
- The level of capital expenditures we make;
- The restrictions contained in our indentures and Credit Facility and our debt service requirements;
- The cost of acquisitions, if any;
- Fluctuations in our working capital needs; and
- Our ability to borrow.

Our cash flow depends heavily on the earnings and distributions of WPZ

Our partnership interest in WPZ is our largest cash-generating asset. Therefore, our cash flow is heavily dependent upon the ability of WPZ to make distributions to its partners. A significant decline in WPZ's earnings and/or distributions would have a corresponding negative impact on us.

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. Some of our competitors are large oil, natural gas and petrochemical companies that have greater access to supplies of natural gas and NGLs than we do. 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. 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. 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. There can be no assurance that we will be able to compete successfully against current and future competitors and any failure to do so could have a material adverse effect on our business, results of operations, financial condition and cash flows.

We may not be able to replace, extend, or add additional customer contracts or contracted volumes on favorable terms, if at all, which could affect our financial condition, the amount of cash available to pay dividends, and our ability to grow.

We rely on a limited number of customers and producers for a significant portion of our revenues and supply of natural gas and NGLs. Although many of our customers and suppliers are subject to long-term contracts, if we are unable to replace or extend such contracts or add additional customers, each on favorable terms, if at all, our financial condition, growth plans, and the amount of cash available to pay distributions could be adversely affected. Our ability to replace, extend, or add additional significant customer or supplier contracts on favorable terms is subject to a number of factors, some of which are beyond our control, including, but not limited to:

- The level of existing and new competition in our businesses or from alternative fuel sources, such as electricity, coal, fuel oils, or nuclear energy.

- Natural gas, NGL, and olefins prices, demand, availability and margins in our markets. Higher prices for energy commodities related to our businesses could result in a decline in the demand for those commodities and, therefore, in customer contracts or throughput on our pipeline systems. Also, lower energy commodity prices could result in a decline in the production of energy commodities resulting in reduced customer contracts, supply contracts, and throughput on our pipeline systems.
- General economic, financial markets and industry conditions.
- The effects of regulation on us, our customers and contracting practices.

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

There are operational risks associated with the gathering, transporting, storage, processing and treating of natural gas, the fractionation, transportation and storage of NGLs, processing of olefins, and crude oil transportation and production handling, including:

- Hurricanes, tornadoes, floods, fires, extreme weather conditions, and other natural disasters;
- Aging infrastructure and mechanical problems;
- Damages to pipelines and pipeline blockages or other pipeline interruptions;
- Uncontrolled releases of natural gas (including sour gas), NGLs, brine or industrial chemicals;
- Collapse or failure of storage caverns;
- Operator error;
- Damage caused by third-party activity, such as operation of construction equipment;
- Pollution and other environmental risks;
- Fires, explosions, craterings and blowouts;
- Truck and rail loading and unloading;
- Operating in a marine environment; and
- 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.

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 certain physical assets that 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 be 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. Offshore assets are covered for property damage when loss is due to a named windstorm event but coverage for loss caused by a named windstorm is significantly sub-limited and subject to a large deductible. 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, to the insurance coverage described above, we are a member of Oil Insurance Limited (OIL), an energy industry mutual insurance company, which provides coverage for damage to our property. As an insured member of OIL, we share in the losses among other OIL members even if our property is not damaged.

Furthermore, 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, results of operations, financial condition, cash flows and our ability to repay our debt.

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

Our assets and operations, especially those located offshore, can be adversely affected by hurricanes, floods, earthquakes, landslides, tornadoes and other natural phenomena and weather conditions, including extreme or unseasonable temperatures, making it more difficult for us to realize the historic rates of return associated with these assets and operations. A significant disruption in operations or a significant liability for which we are not fully insured could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

Our business could be negatively impacted by security threats, including cybersecurity threats, and related disruptions.

We rely on our information technology infrastructure to process, transmit and store electronic information, including information we use to safely operate our assets. While we believe that we maintain appropriate information security policies and protocols, we face cybersecurity and other security threats to our information technology infrastructure, which could include threats to our operational and safety systems that operate our pipelines, plants and assets. We could face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, whether state-sponsored groups, "hacktivists," or private individuals. The age, operating systems or condition of our current information technology infrastructure and software assets and our ability to maintain and upgrade such assets could affect our ability to resist cybersecurity threats. We could also face attempts to gain access to information related to our assets through attempts to obtain unauthorized access by targeting acts of deception against individuals with legitimate access to physical locations or information.

Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-to-day operations. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, safety incidents, damage to the environment, potential liability or the loss of contracts, and have a material adverse effect on our operations, financial position and results of operations.

We could be subject to penalties and fines if we fail to comply with laws governing our businesses.

Our businesses are regulated by numerous governmental agencies including, but not limited to, the FERC, the EPA and the PHMSA. Should we fail to comply with applicable statutes, rules, regulations and orders, our businesses could be subject to substantial penalties and fines. For example, 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 and under the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, the PHMSA has civil penalty authority up to $200,000 per day, with a maximum of $2 million for any related series of violations. Any material penalties or fines under these or other statutes, rules, regulations or orders could have a material adverse impact on our 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 interstate pipelines and storage facilities;
- Acquisition, extension, disposition or abandonment of existing interstate pipelines and storage facilities;
- Accounts and records;
- Depreciation and amortization policies;
- Relationships with affiliated companies who are involved in marketing functions of the natural gas business; and
- Market manipulation in connection with interstate sales, purchases or transportation of natural gas.

Under the NGA, the 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 the FERC. In addition, the 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.

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.

We are subject to risks associated with climate change and the regulation of greenhouse gas emissions.

Climate change and the costs that may be associated with its impacts and with the regulation of emissions of greenhouse gases (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.

In addition, legislative and regulatory responses related to GHGs and climate change create the potential for financial risk.

The U.S. Environmental Protection Agency (EPA) has issued a final determination that six GHG emissions are a threat to public safety and welfare and implemented permitting for new and/or modified large sources of GHG emissions. Increased public awareness and concern over climate change may result in additional state, regional and/or federal requirements to reduce or mitigate GHG emissions. The U.S. Congress and certain states have for some time been considering various forms of legislation related to GHG emissions and additional regulation of GHG emissions in our industry may be implemented under existing Clean Air Act programs. There have also been international efforts seeking legally binding reductions in emissions of GHGs.

Regulatory actions by the EPA or the passage of new 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. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products and services by making our products and services less desirable than competing sources of energy.

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

Substantial costs, liabilities, delays and other significant issues related to environmental laws and regulations are inherent in the gathering, transportation, storage, processing and treating of natural gas, fractionation, transportation and storage of NGLs, processing of olefins, and crude oil transportation and production handling, as a result, we may be required to make substantial expenditures that could exceed current expectations. Our operations are subject to extensive federal, state, tribal and local laws and regulations governing environmental protection, endangered and threatened species, the discharge of materials into the environment and the security of chemical and industrial facilities.

Various governmental authorities, including the EPA, the U.S. Department of the Interior, the Bureau of Indian Affairs and analogous state agencies and tribal governments, 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, the issuance of injunctions limiting or preventing some or all of our operations and delays in granting permits.

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 as they are gathered, transported, processed, fractionated and stored, air emissions related to our operations, historical industry operations, waste and 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, for the remediation of contaminated areas and in connection with spills or releases of materials associated with natural gas, oil 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 noncompliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party hydrocarbon storage and processing or oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. 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 changed regulations and increased costs due to stricter pollution control requirements or liabilities resulting from noncompliance with required operating or other regulatory permits. We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretation of those laws and regulations. If the interpretation of the laws and regulations themselves change, our assumptions and expectations may also 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. 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.

Increased regulation of energy extraction activities, including hydraulic fracturing, could result in reductions or delays in drilling and completing new oil and natural gas wells, which could decrease the volumes of natural gas and other products that we transport, gather, process and treat.

Hydraulic fracturing, a practice involving the injection of water, sand and chemicals under pressure into tight geologic formations to stimulate oil and natural gas production, is currently exempt from federal regulation pursuant to the federal Safe Drinking Water Act (except when the fracturing fluids or propping agents contain diesel fuels). However, public concerns have been raised related to its potential environmental impact and there have been recent initiatives at the federal, state and local levels to regulate or otherwise restrict the use of hydraulic fracturing. Several states have adopted regulations that impose permitting, disclosure and well-completion requirements on hydraulic fracturing operations. The EPA has also announced regulatory and enforcement initiatives related to hydraulic fracturing and other natural gas extraction and production activities. We cannot predict whether any additional federal, state or local laws or regulations will be enacted in this area and if so, what their provisions would be. If new regulations are imposed related to oil and gas extraction, or if additional levels of reporting, regulation or permitting moratoria are required or imposed related to hydraulic fracturing, the volumes of natural gas and other products that we transport, gather, process and treat could decline and our results of operations could be adversely affected.

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 other facilities, their continuing operation is not within our control. If these pipelines or facilities were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to 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.

Legal and regulatory proceedings and investigations relating to the energy industry have adversely affected our business and may continue to do so. The operation of our businesses might also be adversely affected by changes in government regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Public and regulatory scrutiny of the energy industry has resulted in increased regulations being either proposed or implemented. Such scrutiny has also resulted in various inquiries, investigations and court proceedings. 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 ongoing inquiries, investigations and court 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.

In addition, 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, cash flows and ability to pay interest on our indebtedness. For example, various legislative and regulatory reforms associated with pipeline safety and integrity have been proposed or enacted, including the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 enacted on January 3, 2012. This law will result in the promulgation of new regulations to be administered by PHMSA affecting the operations of our gas pipelines including, but not limited to, requirements relating to pipeline inspection, installation of additional valves and other equipment and records verification. These reforms and any future changes in related laws and regulations could significantly increase our costs and impact our operations. In addition, the FERC or competition in our markets may not allow us to recover such costs in the rates we charge for our services.

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.

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

Revenues from certain components 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.

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, financial condition and cash flows.

Difficult conditions in the global capital markets, the credit markets and the economy in general could negatively affect our business and results of operations.

Our businesses may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are reduced energy 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 reduce our access to credit markets, raise the cost of such access or require us to provide additional collateral to our counterparties. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures. In addition, financial markets have recently been affected by concerns over U.S. fiscal policy, including uncertainty regarding federal spending and tax policy, as well as the U.S. federal government's debt ceiling and the federal deficit. These concerns, as well as actions taken by the U.S. federal government in response to these concerns, could significantly and adversely impact the global and U.S. economies and financial markets, which could negatively impact us in the manners described above.

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

A downgrade of our credit ratings 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 ratings and other disruptions. Such disruptions could include:

- Economic downturns;
- Deteriorating capital market conditions;
- Declining market prices for natural gas, NGLs, olefins, oil and other commodities;
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies; and
- 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. This 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.

We are exposed to the credit risk of our customers and counterparties, 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 and counterparties 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 and counterparty credit risk. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers' and counterparties' creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties, 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.

Restrictions in our debt agreements and our leverage may affect our future financial and operating flexibility.

Our total outstanding long-term debt (including current portion) as of December 31, 2012, was $10.7 billion.

The agreements governing our indebtedness contain covenants that restrict our and our material subsidiaries' ability to incur certain liens to support indebtedness and our ability to merge or consolidate or sell all or substantially all of our assets. In addition, certain of our debt agreements contain various covenants that restrict or limit, among other things, our ability to make certain distributions during the continuation of an event of default, the ability of our subsidiaries to incur additional debt, and our and our material subsidiaries' ability to enter into certain affiliate transactions and certain restrictive agreements. Certain of our debt agreements also contain, and those we enter into in the future may contain, financial covenants and other limitations with which we will need to comply.

Our debt service obligations and the covenants described above could have important consequences. For example, they could:

- Make it more difficult for us to satisfy our obligations with respect to our indebtedness, which could in turn result in an event of default on such indebtedness;

- Impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes;
- Adversely affect our ability to pay cash dividends to stockholders;
- Diminish our ability to withstand a continued or future downturn in our business or the economy generally;
- Require us to dedicate a substantial portion of our cash flow from operations to debt service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes;
- Limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate, including limiting our ability to expand or pursue our business activities and preventing us from engaging in certain transactions that might otherwise be considered beneficial to us;
- Place us at a competitive disadvantage compared to our competitors that have proportionately less debt.

Our ability to comply with our debt covenants, 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 and may differ materially from our current assumptions. 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 comply with these covenants, meet our debt service obligations or obtain future credit on favorable terms, or 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.

Our failure to comply with the covenants in the documents governing our indebtedness could result in events of default, which could render such indebtedness due and payable. We may not have sufficient liquidity to repay our indebtedness in such circumstances. In addition, cross-default or cross-acceleration provisions in our debt agreements could cause a default or acceleration to have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. 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".

We are not prohibited under our indentures from incurring additional indebtedness. Our incurrence of significant additional indebtedness would exacerbate the negative consequences mentioned above, and could adversely affect our ability to repay our existing indebtedness.

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

In certain areas of our business, institutional knowledge resides with employees who have many years of service. As these employees reach retirement age their services are no longer available to us, 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.

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, olefins, 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.

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

The systems we use to quantify commodity price risk associated with our businesses 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 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; and
- 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 "Dodd-Frank Act") was enacted. The Dodd-Frank Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Among other things, the Dodd-Frank Act provides for the creation of position limits for certain derivatives transactions, as well as requiring certain transactions to be transacted on exchanges for which cash collateral will be required. These new rules and regulations could increase the cost 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 to a large extent be exempt from the requirement to trade these transactions on exchanges and to clear these transactions through a central clearing house or to post collateral, the impact upon our businesses will depend on the outcome of the implementing regulations that are continuing to be adopted by the Commodities Futures Trading Commission.

A number of our financial derivative transactions used for hedging purposes are currently executed on exchanges and cleared through clearing houses that already require the posting of margins based on initial and variation requirements. Final rules promulgated under the Dodd-Frank Act may require us to post additional cash or new margin to the clearing house or to our counterparties in connection with our hedging transactions. Posting such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures or other corporate purposes. 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 Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

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 post-retirement 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 interest 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 that any such new laws or regulations could have. In addition, the Financial Accounting Standards Board, the SEC or the FERC could enact new accounting standards or the FERC could issue rules 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, political and legal conditions and regulatory environment in the countries in which we have interests or in which we might pursue acquisition or investment opportunities present risks that are different from or greater than those in the United States. These risks include 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, including with respect to the prices we realize for the commodities we produce and sell. 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.

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

Certain of our accounting and information technology services are currently provided by third party vendors, and sometimes from service centers outside of the United States. Service provided pursuant to these agreements could be disrupted. Similarly, the expiration of such agreements or the transition of services between providers could lead to loss of institutional knowledge or service disruptions.

If there is a determination that the spin-off of WPX Energy, Inc. (WPX) stock to our stockholders is taxable for U.S. federal income tax purposes because the facts, representations or undertakings underlying an IRS private letter ruling or a tax opinion are incorrect or for any other reason, then we and our stockholders could incur significant income tax liabilities.

In connection with our original separation plan that called for an initial public offering (IPO) of stock of WPX and a subsequent spin-off of our remaining shares of WPX to our stockholders, we obtained a private letter ruling from the Internal Revenue Service (IRS) and an opinion of our outside tax advisor, to the effect that the distribution by us of WPX shares to our stockholders, and any related restructuring transaction undertaken by us, would not result in recognition for U.S. federal income tax purposes, of income, gain or loss to us or our stockholders under section 355 and section 368(a)(1)(D) of the Internal Revenue Code of 1986 (the Code), except for cash payments made to our stockholders in lieu of fractional shares of WPX common stock. In addition, we received an opinion from our outside tax advisor to the effect that the spin-off pursuant to our revised separation plan which was ultimately consummated on December 31, 2011, which did not involve an IPO of WPX shares, would not result in the recognition, for federal income tax purposes, of income, gain or loss to us or our stockholders under section 355 and section 368(a)(1)(D) of the Code, except for cash payments made to our stockholders in lieu of fractional shares of WPX. The private letter ruling and opinion have relied on or will rely on certain facts, representations, and undertakings from us and WPX regarding the past and future conduct of the companies' respective businesses and other matters. If any of these facts, representations, or undertakings are, or become, incorrect or are not otherwise satisfied, including as a result of certain significant changes in the stock ownership of us or WPX after the spin-off, or if the IRS disagrees with any such facts and representations upon audit, we and our stockholders may not be able to rely on the private letter ruling or the opinion of our tax advisor and could be subject to significant income tax liabilities.

The spin-off may expose us to potential liabilities arising out of state and federal fraudulent conveyance laws and legal dividend requirements that we did not assume in our agreements with WPX.

The spin-off is subject to review under various state and federal fraudulent conveyance laws. A court could deem the spin-off or certain internal restructuring transactions undertaken by us in connection with the separation to be a fraudulent conveyance or transfer. Fraudulent conveyances or transfers are defined to include transfers made or obligations incurred with the actual intent to hinder, delay or defraud current or future creditors or transfers made or obligations incurred for less than reasonably equivalent value when the debtor was insolvent, or that rendered the debtor insolvent, inadequately capitalized or unable to pay its debts as they become due. A court could void the transactions or impose substantial liabilities upon us, which could adversely affect our financial condition and our results of operations. Whether a transaction is a fraudulent conveyance or transfer will vary depending upon the jurisdiction whose law is being applied. Under the separation and distribution agreement between us and WPX, from and after the spin-off, each of WPX and we are responsible for the debts, liabilities and other obligations related to the business or businesses which each owns and operates. Although we do not expect to be liable for any such obligations not expressly assumed by us pursuant to the separation and distribution agreement, it is possible that a court would disregard the allocation agreed to between the parties, and require that we assume responsibility for obligations allocated to WPX, particularly if WPX were to refuse or were unable to pay or perform the subject allocated obligations.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

Please read "Business" for a description of the location and general character of our principal physical properties. We generally own facilities, although a substantial portion of our pipeline and gathering facilities is constructed and maintained pursuant to rights-of-way, easements, permits, licenses or consents on and across properties owned by others.

Item 3. *Legal Proceedings*

Environmental

Certain reportable legal proceedings involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment are described below. While it is not possible for us to predict the final outcome of the proceedings which are still pending, we do not anticipate a material effect on our consolidated financial position if we receive an unfavorable outcome in any one or more of such proceedings.

In September 2007, the EPA requested, and Transco later provided, information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA's investigation of Transco's 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. Transco met with the EPA in May 2008 and submitted a response denying the allegations in June 2008. In May 2011, Transco provided additional information to the EPA pertaining to these compressor stations in response to a request they had made in February 2011. In August 2010, the EPA requested, and Transco provided, similar information for a compressor station in Maryland.

In September 2011, the Colorado Department of Public Health and Environment proposed a penalty of $301,000 for alleged violations of the Colorado Clean Water Act related to excavation work being done for our Crawford Trail Pipeline. Under a settlement reached with the agency in November 2011, we agreed to pay $275,000, which was paid in November 2012.

Other

The additional information called for by this item is provided in Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8. Financial Statements of this report, which information is incorporated by reference into this item.

Item 4. *Mine Safety Disclosures*

Not applicable.

Executive Officers of the Registrant

The name, age, period of service, and title of each of our executive officers as of February 22, 2013, are listed below.

Alan S. Armstrong . . . . Director, Chief Executive Officer, and President

Age: 50

Position held since January 2011.

From February 2002 until January 2011 Mr. Armstrong was Senior Vice President-Midstream and acted as President of our midstream business. From 1999 to February 2002, he was Vice President, Gathering and Processing for our midstream business. From 1998 to 1999 he was Vice President, Commercial Development for Midstream. Mr. Armstrong served as Senior Vice President — Midstream of the general partner of WPZ and Chief Operating Officer from 2005 until February 2010. Mr. Armstrong also serves as Chairman of the Board and Chief Executive Officer of Williams Partners GP LLC, the general partner of WPZ. Since December 2012, Mr. Armstrong has served as a director of Access Midstream Partners GP, L.L.C., the general partner of Access Midstream Partners, L.P. (a midstream natural gas service provider), in which we own an interest.

Francis (Frank) E. Billings	Senior Vice President — Northeast G&P Age: 50 Position held since January 2013. Mr. Billings served as a Vice President of our midstream gathering and processing business from January 2011 until January 2013 and as Vice President, Business Development from August 2010 to January 2011. Mr. Billings served as President of Cumberland Plateau Pipeline Company (a privately held company developing an ethane pipeline to serve the Marcellus shale area) from July 2009 until July 2010. From July 2008 to June 2009, Mr. Billings served as Senior Vice President of Commercial for Crosstex Energy, Inc. and Crosstex Energy L.P. (an independent midstream energy services master limited partnership and its parent corporation). In 1988, Mr. Billings joined MAPCO Inc., which merged with a Williams subsidiary in 1998, serving in various management roles, including in 2008 as a Vice President in the midstream business. Since January 2013, Mr. Billings has also served as Senior Vice President — Northeast G&P of the general partner of WPZ.
Allison G. Bridges	Senior Vice President — West Age 53 Position held since January 2013. Ms. Bridges served as the Vice President and General Manager of Williams Gas Pipeline — West from July 2010 until January 2013. From May 2003 to July 2010, Ms. Bridges was Vice President Commercial Operations for Northwest Pipeline. Ms. Bridges joined Transco in 1981, now a subsidiary of us and WPZ, holding various management positions in accounting, rates, planning and business development. Since January 2013, Ms. Bridges has also served as the Senior Vice President — West of Williams Partners GP LLC, the general partner of WPZ.
Donald R. Chappel	Senior Vice President and Chief Financial Officer Age: 61 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. Since December 2012, Mr. Chappel has served as a director of Access Midstream Partners GP, L.L.C., the general partner of Access Midstream Partners, L.P. (a midstream natural gas service provider) in which we own an interest. Mr. Chappel has also served as a member of the Management Committee of Northwest Pipeline since October 2007. He was Chief Financial Officer from August 2007 and a director from January 2008 of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P., until its merger with WPZ in August 2010. Mr. Chappel is a director of SUPERVALU, Inc. (a grocery and pharmacy company), chairman of its finance committee and a member of its audit committee.

Robyn L. Ewing .... Senior Vice President and Chief Administrative Officer

Age: 57

Position held since April 2008.

From May 2004 to April 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.

Rory L. Miller .... Senior Vice President — Atlantic — Gulf

Age: 52

Position held since January 2013.

From January 2011 until January 2013, Mr. Miller served as Senior Vice President — Midstream of us and the general partner of WPZ, acting as President of our midstream business. He was a Vice President of our midstream business from May 2004 until January 2011. Mr. Miller also serves as a director and as Senior Vice President — Atlantic-Gulf of the general partner of WPZ.

Craig L. Rainey .... Senior Vice President and General Counsel

Age: 60

Position held since January 2012.

Mr. Rainey has served as Senior Vice President and General Counsel since January 2012. From February 2001 to January 2012, Mr. Rainey served as an Assistant General Counsel of Williams, primarily supporting our midstream business and former exploration and production business. He joined Williams in 1999 as a senior counsel and has practiced law since 1977. He has also served as the General Counsel of the general partner of WPZ since January 2012.

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

Age: 56

Position held since July 2005.

Mr. Timmermans served as Assistant Controller of Williams from April 1998 to July 2005. Mr. Timmermans is also Vice President, Controller & Chief Accounting Officer of the general partner of WPZ and served as Chief Accounting Officer of Williams Pipeline Partners GP LLC, the general partner of Williams Pipeline Partners L.P. from January 2008 until its merger with WPZ in August 2010.

Randy M. Newcomer .... Interim Senior Vice President — NGL & Petchem Services

Age: 60

Position held since January 2013.

Mr. Newcomer served as Vice President — Operations Performance of our midstream business since 2010, managing since 2011 the team that reorganized our senior management structure. From 2004 to 2010, he was a vice president for Williams' olefins and natural gas liquids business. From 1996 to 2004, he was a vice president for refining and marketing operations of Williams or MAPCO Inc. which merged with Williams in 1998. Since January 2013, Mr. Newcomer has also served as Interim Senior Vice President — NGL & Petchem Services of the general partner of WPZ.

Fred E. Pace .... Senior Vice President — E&C (Engineering and Construction)

Age: 51

Position held since January 2013.

From January 2011 until January 2013, Mr. Pace served Williams in project engineering and development roles, including service as Vice President Engineering and Construction for our midstream business. From December 2009 to January 2011, Mr. Pace was the managing member of PACE Consulting, LLC (an engineering and consulting firm serving the energy industry). In August 2003, Mr. Pace co-founded Clear Creek Natural Gas, LLC, later known as Clear Creek Energy Services, LLC (a provider of engineering, construction, and operational services to the energy industry) where he served as Chief Executive Officer until December 2009. Mr. Pace has over 25 years of experience in the engineering, construction, operation, and project management areas of the energy industry, including prior service with Williams from 1985 to 1990. Since January 2013, Mr. Pace has also served as Senior Vice President — E&C of the general partner of WPZ.

Brian L. Perilloux .... Senior Vice President — Operational Excellence

Age: 51

Position held since January 2013.

Mr. Perilloux served as a Vice President of our midstream business from January 2011 until January 2013. From August 2007 to January 2011, Mr. Perilloux served in various roles in our midstream business, including engineering and construction roles. Prior to joining Williams, Mr. Perilloux was an officer of a private international engineering and construction company. Since January 2013, Mr. Perilloux has also served as Senior Vice President — Operational Excellence of Williams Partners GP LLC, the general partner of WPZ.

James E. Scheel . . . . Senior Vice President — Corporate Strategic Development

Age: 48

Position held since February 2012.

From January 2011 until February 2012, Mr. Scheel served as Vice President of Business Development for our midstream business. He joined Williams in 1988 and has served in leadership roles in business strategic development, engineering and operations, our NGL business, and international operations. Since December 2012, Mr. Scheel has served as a director of Access Midstream Partners GP, L.L.C., the general partner of Access Midstream Partners, L.P. (a midstream natural gas service provider), in which we own an interest. Mr. Scheel also serves as a director and as Senior Vice President — Corporate Strategic Development of the general partner of WPZ.

PART II

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

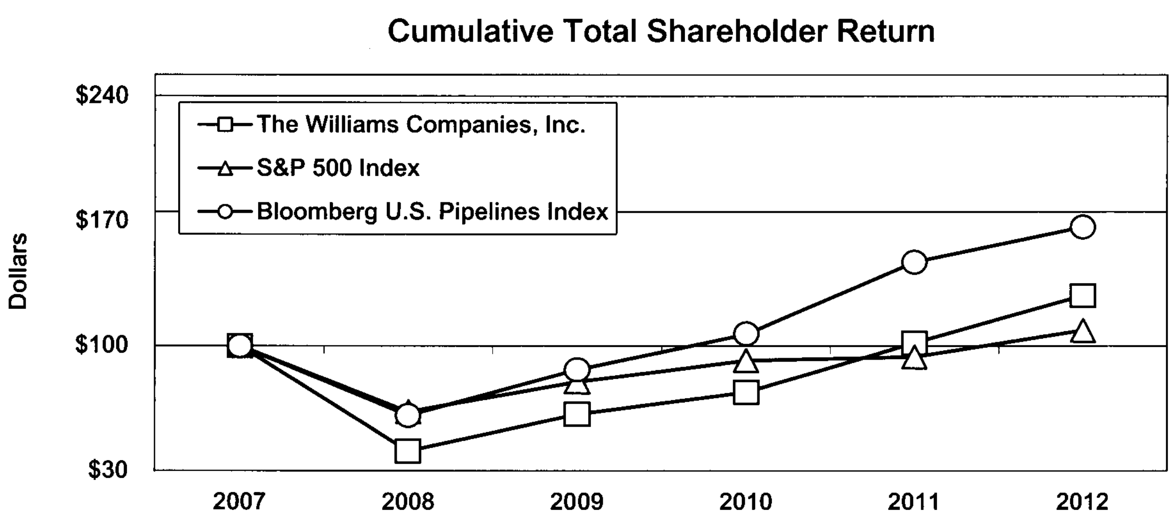
Our common stock is listed on the New York Stock Exchange under the symbol "WMB." At the close of business on February 21, 2013, we had approximately 8,843 holders of record of our common stock. The high and low sales price ranges (New York Stock Exchange composite transactions) and dividends declared by quarter for each of the past two years are as follows:

	2012			2011		
Quarter	High	Low	Dividend	High	Low	Dividend
1st	$32.09	$26.21	$0.25875	$31.77	$24.26	$0.125
2nd	$34.63	$27.25	$ 0.30	$33.47	$27.92	$ 0.20
3rd	$35.39	$28.47	$ 0.3125	$33.16	$23.46	$ 0.20
4th	$37.56	$30.55	$ 0.325	$33.11	$21.90	$ 0.25

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, 2008. The Bloomberg U.S. Pipeline Index is composed of Enbridge, Kinder Morgan, ONEOK, Inc., Spectra Energy, TransCanada Corp., and Williams. The graph below assumes an investment of $100 at the beginning of the period.



	2007	2008	2009	2010	2011	2012
The Williams Companies, Inc.	100.0	41.2	61.7	74.0	101.4	128.0
S&P 500 Index	100.0	63.0	79.7	91.7	93.6	108.6
Bloomberg U.S. Pipelines Index	100.0	61.1	86.6	106.5	146.8	166.6

The information presented in the performance graph has been recast to reflect the WPX spin-off completed on December 31, 2011.

Item 6. *Selected Financial Data*

The following financial data at December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, 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.

	2012	2011	2010	2009	2008
	(Millions, except per-share amounts)				
Revenues	$ 7,486	$ 7,930	$ 6,638	$ 5,278	$ 6,904
Income (loss) from continuing operations (1)	929	1,078	271	346	682
Amounts attributable to The Williams Companies, Inc.:					
Income (loss) from continuing operations	723	803	104	206	528
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	1.15	1.34	0.17	0.35	0.90
Total assets at December 31 (2) (3)	24,327	16,502	24,972	25,280	26,006
Short-term notes payable and long-term debt due within one year at December 31	1	353	508	17	18
Long-term debt at December 31 (3)	10,735	8,369	8,600	8,259	7,683
Stockholders' equity at December 31 (2) (3)	4,752	1,296	6,803	7,990	7,983
Cash dividends declared per common share	1.196	0.775	0.485	0.44	0.43

(1) Income from continuing operations for 2011 includes $271 million of pre-tax early debt retirement costs and 2010 includes $648 million of pre-tax costs associated with our strategic restructuring transaction in the first quarter of 2010. See Note 5 of Notes to Consolidated Financial Statements for further discussion of asset sales and other accruals in 2012, 2011, and 2010.

(2) Total assets and stockholders' equity for 2011 decreased due to the special dividend to spin off our former exploration and production business.

(3) The increases in 2012 reflect assets and investments acquired, primarily related to the Caiman and Laser Acquisitions and our investment in Access Midstream Partners, as well as debt and equity issuances.

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

General

We are an energy infrastructure company focused on connecting North America's significant hydrocarbon resource plays to growing markets for natural gas, natural gas liquids (NGLs), and olefins. Our operations span from the deepwater Gulf of Mexico to the Canadian oil sands and include midstream gathering and processing assets, an olefins production facility, and interstate natural gas pipelines held through our significant investment in Williams Partners L.P. (NYSE: WPZ), of which we currently own approximately 70 percent, including the general partner interest. We also process oil sands offgas in Canada and hold an overall approximate 25 percent interest in Access Midstream Partners, L.P. (NYSE: ACMP), including a 50 percent interest in the general partner and the associated incentive distribution rights. ACMP owns and operates midstream assets located in the Barnett, Eagle Ford, Haynesville, Marcellus, Niobrara and Utica shales and Mid-Continent region.

We are organized into the Williams Partners, Williams NGL & Petchem Services, and Access Midstream Partners reportable segments. All remaining business activities are included in Other. (See Note 1 of Notes to Consolidated Financial Statements 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.

Acquisitions

In February 2012, WPZ completed the acquisition of 100 percent of the ownership interests in certain entities from Delphi Midstream Partners, LLC (Laser Acquisition). These entities primarily own the Laser Gathering System, which is comprised of 33 miles of 16-inch natural gas pipeline and associated gathering facilities in the Marcellus Shale in Susquehanna County, Pennsylvania, as well as 10 miles of gathering lines in southern New York. This acquisition represents a strategic platform to enhance WPZ's expansion in the Marcellus Shale by providing our customers with both operational flow assurance and marketing flexibility. (See Results of Operations — Segments, Williams Partners.)

In April 2012, WPZ completed the acquisition of 100 percent of the ownership interest in Caiman Eastern Midstream, LLC (Caiman Acquisition). The acquired entity operates a gathering and processing business in northern West Virginia, southwestern Pennsylvania and eastern Ohio. WPZ believes this acquisition will provide it with a significant footprint and growth potential in the NGL-rich portion of the Marcellus Shale. (See Results of Operations — Segments, Williams Partners.)

In December 2012, we made significant investments in Access Midstream Partners GP, L.L.C. (Access GP) and Access Midstream Partners, L.P. (ACMP) (collectively referred to as Access Midstream Partners). We now own a 50 percent indirect interest in Access GP which holds the 2 percent general partner interest in ACMP and incentive distribution rights. In addition, we hold approximately 24 percent limited partner interest in ACMP for a combined ownership interest of approximately 25 percent of ACMP. ACMP is a publicly traded master limited partnership that owns, operates, develops and acquires natural gas gathering systems and other midstream energy assets, which bolsters our position in the Marcellus and Utica shale plays and adds diversity via the Eagle Ford, Haynesville, Barnett, Mid-Continent and Niobrara areas. (See Results of Operations — Segments, Access Midstream Partners.)

Dividend Growth

We increased our quarterly dividends from $0.25 per share in the fourth quarter of 2011 to $0.325 per share in the fourth-quarter of 2012. Also, consistent with our expectation of receiving increasing cash distributions from our interests in WPZ and Access Midstream Partners, we expect to increase our dividend on a quarterly basis. Our Board of Directors has approved a dividend of $0.33875 per share for the first quarter of 2013 and we expect a 20 percent annual increase in total dividends in both 2013 and 2014.

Overview

During the second quarter 2012, NGL margins declined sharply largely attributable to a record-warm winter, a slowing global economy, and growing NGL supplies. The downward trend of per-unit NGL margins leveled-off during the second-half of 2012. We have been impacted by this environment as our 2012 *income (loss) from continuing operations attributable to The Williams Companies, Inc.* decreased by $80 million compared to 2011. This decrease is primarily due to an unfavorable change in *operating income (loss)* and the absence of certain income tax provision benefits recognized in 2011, partially offset by the absence of *early debt retirement costs* incurred in 2011. See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for 2012 decreased $1.604 billion compared to 2011, largely due to the absence of operating cash flows from our former exploration and production business and lower operating results.

Abundant and low-cost natural gas reserves in the United States continue to drive strong demand for midstream and pipeline infrastructure. We believe we have successfully positioned our energy infrastructure businesses for significant future growth, as highlighted by the following accomplishments during 2012 through the present:

Recent Events

In addition to the previously discussed acquisitions, we note the following:

- In February 2012, we announced a new interstate gas pipeline project. The new 120-mile Constitution Pipeline will connect Williams Partners' gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems. We currently own 51 percent of Constitution Pipeline with two other parties holding 25 percent and 24 percent, respectively. This project, along with the newly acquired Laser Gathering System and our Springville pipeline, are key steps in Williams Partners' strategy to create the Susquehanna Supply Hub, a major natural gas supply hub in northeastern Pennsylvania. In April 2012, we began the Federal Energy Regulatory Commission (FERC) pre-filing process for the Constitution Pipeline and expect to file a FERC application during the second quarter of 2013.
- In March 2012, a settlement agreement was reached under which our majority-owned entities that owned and operated the El Furrial and PIGAP II gas compression facilities in Venezuela sold the assets of these facilities following their expropriation by the Venezuelan government in 2009. In connection with the settlement, we received $98 million of cash and the right to receive quarterly installments of $15 million through the first quarter of 2016. Also as part of this settlement, we received $63 million in cash in March 2012 related to a previous agreement to sell our interest in Accroven SRL. (See Notes 3 and 4 of Notes to Consolidated Financial Statements.)
- In April 2012, we issued 30 million shares of common stock in a public offering at a price of $30.59 per share. We used the net proceeds of $887 million to fund a portion of the purchase of additional WPZ common units in connection with WPZ's Caiman Acquisition.
- In April 2012, WPZ completed an equity issuance of 10 million common units representing limited partner interests at a price of $54.56 per unit. Subsequently, WPZ sold an additional 973,368 common units for $54.56 per unit to the underwriters upon the underwriters' exercise of their option to purchase additional common units. The net proceeds were used for general partnership purposes, including funding a portion of the cash purchase price of WPZ's Caiman Acquisition.
- In July 2012, Transcontinental Gas Pipe Line Company, LLC (Transco) issued $400 million of 4.45 percent senior unsecured notes due 2042 to investors in a private debt placement. A portion of these proceeds was used to repay Transco's $325 million 8.875 percent senior unsecured notes that matured

on July 15, 2012. 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 November 2012 and completed in December 2012.

- In July 2012, WPZ formed Caiman Energy II, LLC with Caiman Energy, LLC and others to develop large-scale natural gas gathering and processing and the associated liquids infrastructure serving oil and gas producers in the Utica shale, primarily in Ohio and northwest Pennsylvania. As a result, WPZ plans to contribute $380 million through 2014 to fund a portion of Blue Racer Midstream, a joint project formed in December 2012 between Caiman Energy II, LLC and another party.
- In August 2012, WPZ completed an equity issuance of 8,500,000 common units representing limited partner interests at a price of $51.43 per unit. Subsequently, WPZ sold an additional 1,275,000 common units for $51.43 per unit to the underwriters upon the underwriters' exercise of their option to purchase additional common units. The net proceeds of these transactions were primarily used to repay outstanding borrowings on WPZ's senior unsecured revolving credit facility (WPZ's revolver).
- In August 2012, WPZ completed a public offering of $750 million of 3.35 percent senior unsecured notes due 2022. The net proceeds were used to repay outstanding borrowings on WPZ's revolver and for general partnership purposes.
- In November 2012, we contributed to WPZ our 83.3 percent undivided interest and operatorship of an olefins-production facility located in Geismar, Louisiana, along with our refinery grade propylene splitter and pipelines in the Gulf region. These businesses were previously reported through our Williams NGL & Petchem Services segment; however, they are now reported in our Williams Partners segment and prior period segment disclosures have been recast for this transaction. WPZ funded substantially all of the transaction with the issuance of limited partner units to us.
- In November 2012, we completed the purchase of 10 liquids pipelines in the Gulf Coast region. The acquired pipelines will be combined with an organic build-out of several projects to expand our petrochemical services in that region. The projects are expected to be placed into service beginning in late 2014.
- In December 2012, we issued approximately 53 million shares of common stock in a public offering at a price of $31 per share. We used the net proceeds of $1.6 billion to fund a portion of our investment in Access Midstream Partners. (See Note 2 of Notes to Consolidated Financial Statements).
- In December 2012, we completed a public offering of $850 million of 3.7 percent senior unsecured notes due 2023. We used the net proceeds to fund a portion of our investment in Access Midstream Partners. (See Note 2 of Notes to Consolidated Financial Statements).
- In January 2013, WPZ agreed to sell a 49 percent ownership interest in its Gulfstar FPS™ project to a third party. The transaction is expected to close in second-quarter 2013, at which time we expect the third party will contribute $225 million to fund its proportionate share of the project costs, following with monthly capital contributions to fund its share of ongoing construction.

Outlook for 2013

Our strategy is to provide large-scale energy infrastructure designed to maximize the opportunities created by the vast supply of natural gas, natural gas products, and crude oil that exists in North America. We seek to accomplish this through further developing our scale positions in current key markets and basins and entering new growth markets and basins where we can become the large-scale service provider. We will maintain a strong commitment to operational excellence and customer satisfaction. We believe that accomplishing these goals will position us to deliver an attractive return to our stockholders.

Fee-based businesses are a significant component of our portfolio. As we continue to transition to an overall business mix that is increasingly fee-based, the influence of commodity price fluctuations on our operating results and cash flows is expected to become somewhat less significant.

In light of the above, our business plan for 2013 continues to reflect both significant capital investment and dividend growth. Our planned consolidated capital investments for 2013 total approximately $4.275 billion, of which we expect to fund primarily through cash on hand, cash flow from operations, and debt and equity issuances by WPZ. We also expect 20 percent growth in total 2013 dividends, which we expect to fund primarily with distributions received from WPZ. Our structure is designed to drive lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions.

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

- General economic, financial markets, or industry downturn;
- Availability of capital;
- Lower than expected levels of cash flow from operations;
- Counterparty credit and performance risk;
- Decreased volumes from third parties served by our midstream businesses;
- Unexpected significant increases in capital expenditures or delays in capital project execution;
- Lower than anticipated energy commodity prices and margins;
- Changes in the political and regulatory environments;
- Physical damages to facilities, especially damage to offshore facilities by named windstorms.

We continue to address these risks through maintaining a strong financial position and ample liquidity, as well as managing a diversified portfolio of energy infrastructure assets.

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.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Net periodic benefit cost 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 cost and the benefit obligations are shown in Note 8 of Notes to Consolidated Financial Statements.

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

	Benefit Cost		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Millions)			
Pension benefits:				
Discount rate	$ (8)	$ 9	$(148)	$175
Expected long-term rate of return on plan assets	(10)	10	—	—
Rate of compensation increase	2	(1)	9	(7)
Other postretirement benefits:				
Discount rate	(4)	5	(42)	53
Expected long-term rate of return on plan assets	(2)	2	—	—
Assumed health care cost trend rate	7	(5)	46	(38)

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 rates 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 period of at least ten years and take into account 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 rates are an estimate of future results and, thus, likely to be different than actual results.

In 2012, the benefit plans' assets reflected strong equity performance coupled with modest returns from the fixed income strategies. While the 2012 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 7.5 percent since 2010. In 2012, we reduced our expected long-term rate of return on pension assets to 6.3 percent. This reduction was implemented due to a downward trend in long-term capital market expectations and a more conservative asset allocation in the investment portfolio reflecting some shift to more fixed income securities relative to equity securities. The 2012 actual return on plan assets for our pension plans was approximately 12.1 percent. The ten-year average rate of return on pension plan assets through December 2012 was approximately 6.8 percent.

The discount rates are used to measure the benefit obligations of our pension and other postretirement benefit plans. The objective of the discount rates is to determine the amount, if invested at the December 31 measurement date in a portfolio of high-quality debt securities, that will provide the necessary cash flows when benefit payments are due. Increases in the discount rates decrease the obligation and, generally, decrease the related cost. 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 8 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 weighted-average discount rate used to measure our pension plans' benefit obligation declined during 2012 by 55 basis points, which significantly contributed to the actuarial loss of $98 million in the current year.

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

Goodwill and Intangible Assets

At December 31, 2012, our Consolidated Balance Sheet includes $649 million of goodwill and $1.7 billion in intangible assets related to the Laser and Caiman Acquisitions, which were completed earlier this year.

Goodwill

We performed our annual assessment of goodwill for impairment as of October 1. All of our goodwill is allocated to WPZ's midstream business (the reporting unit). In our evaluation, our estimate of the fair value of the reporting unit significantly exceeded its carrying value, including goodwill, and thus no impairment loss was recognized in 2012. If the carrying value of the reporting unit had exceeded its fair value, a computation of the implied fair value of the goodwill would have been compared with its related carrying value. If the carrying value of the reporting unit goodwill had exceeded the implied fair value of that goodwill, an impairment loss would have been recognized in the amount of the excess.

The fair value of WPZ's midstream business was estimated by both an income approach utilizing discounted cash flows and a market approach utilizing EBITDA multiples.

Other intangible assets

We evaluate *other intangible assets* for both changes in the expected remaining useful lives and impairment when events or changes in circumstances indicate, in our management's judgment, that the estimated useful lives have changed or the carrying value of such assets may not be recoverable. Changes in an estimated remaining useful life would be reflected prospectively through amortization over the revised remaining useful life. When an indicator of impairment has occurred, we compare our management's estimate of undiscounted future cash flows attributable to the intangible 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. 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. Indicators of potential impairment may include:

- Laws prohibiting the production of reserves in the areas where our assets from the Laser and Caiman Acquisitions operate;
- The development of alternative energy sources that would halt the production of reserves in these areas; or
- The loss of or failure to renew customer contracts. A significant portion of the value allocated to these contracts in our purchase price allocation was based on our assumptions regarding our ability and intent to renew or renegotiate existing customer contracts. (See Note 2 of Notes to Consolidated Financial Statements.)

We have not evaluated our intangible assets for impairment as of December 31, 2012, as there were no indicators of potential impairment.

Equity-method Investments

At December 31, 2012, our Consolidated Balance Sheet includes approximately $4 billion of investments that are accounted for under the equity method of accounting. We evaluate these 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. We generally estimate the fair value of our investments using an income approach where significant judgments and assumptions include expected future cash flows and the appropriate discount rate. In some cases, we may utilize a form of market approach to estimate the fair value of our investments.

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. Events or changes in circumstances that may be indicative of an other-than-temporary decline in value will vary by investment, but may include:

- A significant or sustained decline in the market value of a publicly-traded investee;
- Lower than expected cash distributions from investees (including incentive distributions);
- Significant asset impairments or operating losses recognized by investees;
- Significant delays in or lack of producer development or significant declines in producer volumes in markets served by investees; and,
- Significant delays in or failure to complete significant growth projects of investees.

No impairments of investments accounted for under the equity method have been recorded for the year ended December 31, 2012.

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, 2012. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2012	$ Change from 2011*	% Change from 2011*	2011	$ Change from 2010*	% Change from 2010*	2010
				(Millions)			
Revenues:							
Service revenues	$2,729	+197	+8%	$2,532	+173	+7%	$ 2,359
Product sales	4,757	-641	-12%	5,398	+1,119	+26%	4,279
Total revenues	7,486			7,930			6,638
Costs and expenses:							
Product costs	3,496	+438	+11%	3,934	-674	-21%	3,260
Operating and maintenance expenses	1,027	-37	-4%	990	-120	-14%	870
Depreciation and amortization expenses	756	-95	-14%	661	-49	-8%	612
Selling, general, and administrative expenses	571	-94	-20%	477	+27	+5%	504
Other (income) expense — net	24	-23	NM	1	-16	NM	(15)
Total costs and expenses	5,874			6,063			5,231
Operating income (loss)	1,612			1,867			1,407
Equity earnings (losses)	111	-44	-28%	155	+12	+8%	143
Interest expense	(509)	+64	+11%	(573)	+19	+3%	(592)
Other investing income — net	77	+64	NM	13	-32	-71%	45
Early debt retirement costs	—	+271	+100%	(271)	+335	+55%	(606)
Other income (expense) — net	(2)	-13	NM	11	+23	NM	(12)
Income (loss) from continuing operations before income taxes	1,289			1,202			385
Provision (benefit) for income taxes	360	-236	-190%	124	-10	-9%	114
Income (loss) from continuing operations	929			1,078			271
Income (loss) from discontinued operations	136	+553	NM	(417)	+776	+65%	(1,193)
Net income (loss)	1,065			661			(922)
Less: Net income attributable to noncontrolling interests	206	+79	+28%	285	-110	-63%	175
Net income (loss) attributable to The Williams Companies, Inc.	$ 859			$ 376			$(1,097)

* + = 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.

2012 vs. 2011

The increase in *service revenues* is primarily due to Williams Partners' higher fee revenues resulting from increased gathering and processing fee revenues from higher volumes in the Marcellus Shale, including new volumes on our recently acquired gathering and processing assets in our Ohio Valley Midstream and Susquehanna Supply Hub businesses and higher volumes in the western deepwater Gulf of Mexico and in the Piceance basin. Additionally, natural gas transportation revenues increased from expansion projects placed into service in 2011 and 2012.

The decrease in *product sales* is primarily due to Williams Partners' lower NGL and olefin production revenues reflecting an overall decrease in average per-unit sales prices, and lower marketing revenues primarily due to significant decreases in NGL and olefin prices, partially offset by higher NGL and crude volumes, as well as new volumes from natural gas marketing activities. In addition, Williams NGL & Petchem Services' production revenues decreased primarily due to lower average per-unit sales prices.

The decrease in *product costs* is primarily due to Williams Partners' lower olefins feedstock costs reflecting a decrease in average per-unit prices and lower costs associated with the production of NGLs primarily resulting from a decrease in average natural gas prices. Marketing purchases at Williams Partners also decreased primarily due to significantly lower average NGL prices, partially offset by higher NGL and crude volumes, as well as new volumes from natural gas marketing activities. Additionally, Williams NGL & Petchem Services' NGL feedstock costs decreased resulting from lower average per-unit costs.

The increase in *operating and maintenance expenses* is primarily due to Williams Partners' increased maintenance expenses primarily associated with its new assets acquired in 2012 and increased employee-related benefit costs, partially offset by lower costs in our Four Corners area related to the consolidation of certain operations.

The increase in *depreciation and amortization expenses* is primarily associated with Williams Partners' new assets acquired in 2012 (see Note 2 of Notes to Consolidated Financial Statements).

The increase in *selling, general, and administrative expenses (SG&A)* is primarily due to an increase at Williams Partners reflecting $23 million of acquisition and transition-related costs as well as higher employee-related and information technology expenses driven by general growth within Williams Partners' business operations. *SG&A* also includes $26 million of reorganization-related costs incurred in 2012 primarily relating to our engagement of a consulting firm to assist in better aligning resources to support our business strategy following the spin-off of WPX and is substantially offset by the absence of general corporate expenses related to the spin-off of WPX, which was completed on December 31, 2011.

The unfavorable change in *other (income) expense — net* within *operating income (loss)* primarily reflects the absence of the Gulf Liquids litigation contingency accrual reduction of $19 million in 2011 at Williams NGL & Petchem Services (see Notes 5 and 17 of Notes to Consolidated Financial Statements).

The unfavorable change in *operating income (loss)* generally reflects lower NGL production and marketing margins, as well as previously described increases in *operating and maintenance expenses, depreciation and amortization expenses, SG&A* and an unfavorable change in *other (income) expense — net.* Higher fee revenues and olefin production margins partially offset these decreases.

The unfavorable change in *equity earnings (losses)* is primarily due to lower Laurel Mountain Midstream, LLC (Laurel Mountain), Aux Sable Liquid Products L.P. (Aux Sable) and Discovery Producer Services LLC (Discovery) equity earnings at Williams Partners primarily reflecting lower operating results of these investees and the impairment of two minor NGL processing plants at Laurel Mountain.

Interest expense decreased due to an increase in *interest capitalized* related to construction projects primarily at Williams Partners, as well as a decrease in *interest incurred* related to corporate debt retirements in December 2011, partially offset by an increase in borrowings at Williams Partners (see Note 12 of Notes to Consolidated Financial Statements) and the absence of a $14 million reduction of an interest accrual related to a litigation contingency in 2011 at Williams NGL & Petchem Services as previously discussed.

The favorable change in *other investing income — net* is primarily due to $63 million of income, including interest, recognized in 2012 as compared to an $11 million gain in 2011 at Other related to the 2010 sale of our interest in Accroven SRL. (See Note 4 of Notes to Consolidated Financial Statements.)

Early debt retirement costs in 2011 reflect costs related to corporate debt retirements in December 2011, including $254 million in related premiums.

Provision (benefit) for income taxes changed unfavorably primarily due to higher pre-tax income, the absence of approximately $147 million tax benefit from federal settlements and an international revised assessment in 2011, and the absence of $66 million deferred tax benefit recognized in 2011 related to the undistributed earnings of certain foreign operations that we considered to be permanently reinvested. See Note 6 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both years.

Income (loss) from discontinued operations in 2012 primarily includes a gain on reconsolidation following the sale of certain of our former Venezuela operations. *Income (loss) from discontinued operations* in 2011 primarily reflects the results of operations of our former exploration and production business as discontinued operations following the spin-off of WPX. See Note 3 of Notes to Consolidated Financial Statements for a more detailed discussion of the items in *income (loss) from discontinued operations.*

The favorable change in *net income attributable to noncontrolling interests* primarily reflects lower operating results at WPZ and higher income allocated to the general partner driven by incentive distribution rights, partially offset by our decreased percentage of limited partner ownership of WPZ, which was 68 percent at December 31, 2012, compared to 73 percent at December 31, 2011.

2011 vs. 2010

The increase in *service revenues* is primarily due to higher Williams Partners' gathering and processing fee revenue in the Marcellus Shale related to gathering assets acquired at the end of 2010, in the western deepwater Gulf of Mexico related to assets placed into service in late 2010, and in the Piceance basin as a result of an agreement executed in November 2010. These increases are partially offset by a decline in fee revenue in the eastern deepwater Gulf of Mexico primarily due to natural field declines. Williams Partners' natural gas transportation revenues increased primarily due to expansion projects placed in service in 2010 and 2011.

The increase in *product sales* is primarily due to higher marketing and NGL and olefin production revenues at Williams Partners as a result of higher average energy commodity prices, partially offset by a decrease in NGL production volumes. Williams NGL & Petchem Services' production revenues increased primarily resulting from higher average energy commodity prices and higher volumes.

The increase in *product costs* is primarily due to increased marketing purchases and olefin feedstock costs at Williams Partners primarily resulting from higher average energy commodity prices. These increases are partially offset by decreased costs associated with production of NGLs reflecting lower average natural gas prices and lower NGL production volumes at Williams Partners.

The increase in *operating and maintenance expenses* is due to increased maintenance expenses and higher property insurance expenses primarily at Williams Partners.

The increase in *depreciation and amortization expenses* is primarily due to assets placed in service late in 2010, along with increased depreciation of a facility, which was idled in 2012, at Williams Partners.

The decrease in *SG&A* is primarily due to the absence of $45 million of transaction costs incurred in 2010 associated with our strategic restructuring transaction.

The unfavorable change in *other (income) expense — net* within *operating income (loss)* primarily reflects:

- $15 million of lower involuntary conversion gains in 2011 as compared to 2010 at Williams Partners due to insurance recoveries that are in excess of the carrying value of the assets;

- The absence of a $12 million gain in 2010 on the sale of certain assets at Williams Partners;
- The absence of a $6 million favorable customer settlement in 2010 at Williams NGL & Petchem Services;
- $4 million lower sales of base gas from Hester Storage field in 2011 compared to 2010 at Williams Partners.

These unfavorable changes are partially offset by:

- $19 million of income related to a litigation contingency accrual reduction in 2011 at Williams NGL & Petchem Services as previously discussed;
- $8 million related to the net reversal of project feasibility costs from expense to capital in 2011 at Williams Partners (see Note 5 of Notes to Consolidated Financial Statements).

The favorable change in *operating income (loss)* generally reflects an improved energy commodity price environment in 2011 compared to 2010, increased fee revenues, and the absence of costs associated with the strategic restructuring in 2010, partially offset by higher operating costs and an unfavorable change in *other (income) expense — net* as previously discussed.

The favorable change in *equity earnings (losses)* is primarily due to an increased ownership interest in Overland Pass Pipeline Company LLC (OPPL) at Williams Partners.

The unfavorable change in *other investing income — net* is primarily due to $32 million of decreased gains recognized in 2011 related to the 2010 sale of our interest in Accroven SRL. (See Note 4 of Notes to Consolidated Financial Statements.)

Early debt retirement costs in 2011 reflect costs related to corporate debt retirements in December 2011, including $254 million in related premiums. *Early debt retirement costs* in 2010 reflect costs related to corporate debt retirements associated with our first quarter 2010 strategic restructuring transaction, including premiums of $574 million.

Other (income) expense — net below *operating income (loss)* changed favorably primarily due to an $11 million decrease in environmental accruals in 2011 as compared to 2010.

Provision (benefit) for income taxes changed unfavorably primarily due to higher pre-tax income, partially offset by federal settlements in 2011 and an adjustment to reverse taxes on undistributed earnings of certain foreign operations that were considered permanently reinvested. See Note 6 of Notes to Consolidated Financial Statements for a reconciliation of the effective tax rates compared to the federal statutory rate for both years.

Income (loss) from discontinued operations reflects the results of operations of our former exploration and production business as discontinued operations. (See Note 3 of Notes to Consolidated Financial Statements.)

The unfavorable change in *net income attributable to noncontrolling interests* reflects higher operating results at WPZ and increased noncontrolling interest ownership of WPZ as a result of WPZ equity issuances in 2010. These changes are partially offset by our greater ownership interest related to WPZ's merger with Williams Pipeline Partners L.P., which was completed in 2010.

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, processing, and treating facilities and oil gathering and transportation facilities located primarily in the Rocky Mountain, Gulf Coast, and Marcellus Shale regions of the United States. WPZ also owns a 5/6 interest in an olefin production facility, along with a refinery grade propylene splitter and pipelines in the Gulf region. As of December 31, 2012, we own approximately 70 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 2012

Significant events during 2012 include the following:

Gulf Olefins production facilities acquisition

In November 2012, we contributed to WPZ an 83.3 percent undivided interest and operatorship of the olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf region. This business was previously reported within our Williams NGL & Petchem Services segment. The acquisition is expected to bring more certainty to cash flows that are currently exposed to volatile ethane prices by shifting the commodity price exposure to ethylene. Located south of Baton Rouge, Louisiana, the Geismar facility is a light-end NGL cracker with current feedstock volumes of 39,000 barrels per day (bpd) of ethane and 3,000 bpd of propane and annual production of 1.35 billion pounds of ethylene. With the benefit of a \$350-\$400 million expansion under way and scheduled for completion by late 2013, the facility's annual ethylene production capacity will grow by 600 million pounds to 1.95 billion pounds. Along with ethane, propane and ethylene, the Geismar facility also produces propylene, butadiene, and debutanized aromatic concentrate (DAC). Prior period segment disclosures have been recast for this transaction.

In the fourth quarter of 2012, we also completed the construction of a pipeline which is capable of supplying 12 Mbbls/d of ethane to our Geismar olefins production facility from Discovery's Paradis fractionator.

Caiman Acquisition

In April 2012, we completed the Caiman Acquisition for consideration valued at approximately \$2.3 billion. The transition of operations is complete.

The acquisition provides us with a significant footprint and growth potential in the natural gas liquids-rich Ohio River Valley area of the Marcellus Shale. The existing physical assets that we acquired include a gathering system, two processing facilities and a fractionator located in northern West Virginia and establish our new Ohio Valley Midstream business. In addition to the acquisition cost, we committed a large portion of our 2012 capital expenditures and continue to commit planned capital expenditures in 2013 and beyond for ongoing expansions to the gathering system, processing facilities, and fractionator, which are currently under construction. NGL pipelines are also planned. The assets are anchored by long-term contracted commitments, including 236,000 dedicated gathering acres from 10 producers in West Virginia, Ohio, and Pennsylvania.

Several projects were completed in the fourth quarter of 2012 increasing our gathering, processing and fractionating capacities. The Fort Beeler plant complex has 320 million cubic feet per day (MMcf/d) of cryogenic processing capacity currently available with another 200 MMcf/d expected during the first quarter of 2013. The Moundsville fractionator is now in service with approximately 13 thousand barrels per day (Mbbls/d) of NGL handling capacity. An NGL pipeline, connecting the Fort Beeler plant to the Moundsville fractionator has also been completed and is in service.

Utica Shale infrastructure project

In July 2012, WPZ formed Caiman Energy II, LLC with Caiman Energy, LLC and others to develop large-scale natural gas gathering and processing and the associated liquids infrastructure serving oil and gas producers in the Utica shale, primarily in Ohio and northwest Pennsylvania. As a result, through our 47.5 percent ownership, WPZ plans to contribute $380 million through 2014 to fund a portion of Blue Racer Midstream, a joint project formed in December 2012 between Caiman Energy II, LLC and another party.

Susquehanna Supply Hub, northeastern Pennsylvania

In April 2012, we began the FERC pre-filing process for a new interstate gas pipeline project. We currently own 51 percent of Constitution Pipeline with two other parties holding 25 percent and 24 percent, respectively. We will be the operator of Constitution Pipeline. The new 120-mile Constitution Pipeline will connect our gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems. The total cost of the entire project is estimated to be $680 million. We plan to place the project into service in March 2015, with an expected capacity of 650 thousand dekatherms per day (Mdth/d). The pipeline is fully subscribed with two shippers. We expect to file a FERC application during the second quarter of 2013.

In February 2012, we completed the Laser Acquisition for $325 million in cash, net of cash acquired in the transaction and subject to certain closing adjustments, and 7,531,381 of our common units valued at $441 million. The gathering system is comprised of 33 miles of 16-inch natural gas pipeline and associated gathering facilities in Susquehanna County, Pennsylvania, as well as 10 miles of gathering pipeline in southern New York. The acquisition is supported by existing long-term gathering agreements that provide acreage dedications and volume commitments.

Our Springville pipeline, a 33-mile, 24-inch diameter natural gas gathering pipeline, connecting a portion of our gathering assets into the Transco pipeline, was placed into service in January 2012, and expansions were completed in the third quarter of 2012 allowing us to deliver approximately 625 MMcf/d into the Transco pipeline. This new take-away capacity allows full use of approximately 1.6 billion cubic feet per day (Bcf/d) of capacity from various compression and dehydration expansion projects to our gathering business in northeastern Pennsylvania's Marcellus Shale which we acquired at the end of 2010.

As production in the Marcellus increases and expansion projects are completed, the Susquehanna Supply Hub is expected to reach a natural gas take away capacity of 3 Bcf/d by 2015, including capacity contributions from the Constitution Pipeline.

Mid-Atlantic Connector

In July 2011, we received approval from the FERC to expand our existing natural gas transmission system from North Carolina to markets as far downstream as Maryland. The capital cost of the project was approximately $60 million. The project was placed into service in the first quarter of 2013, increasing capacity by 142 Mdth/d.

Volume impacts in 2012

Due to third-party NGL pipeline capacity restrictions from our Four Corners plants beginning in late September and to unfavorable ethane economics in December, we reduced our recoveries of ethane in our onshore plants which resulted in 7 percent lower NGL equity sales volumes in the fourth quarter of 2012 compared to the third quarter of 2012.

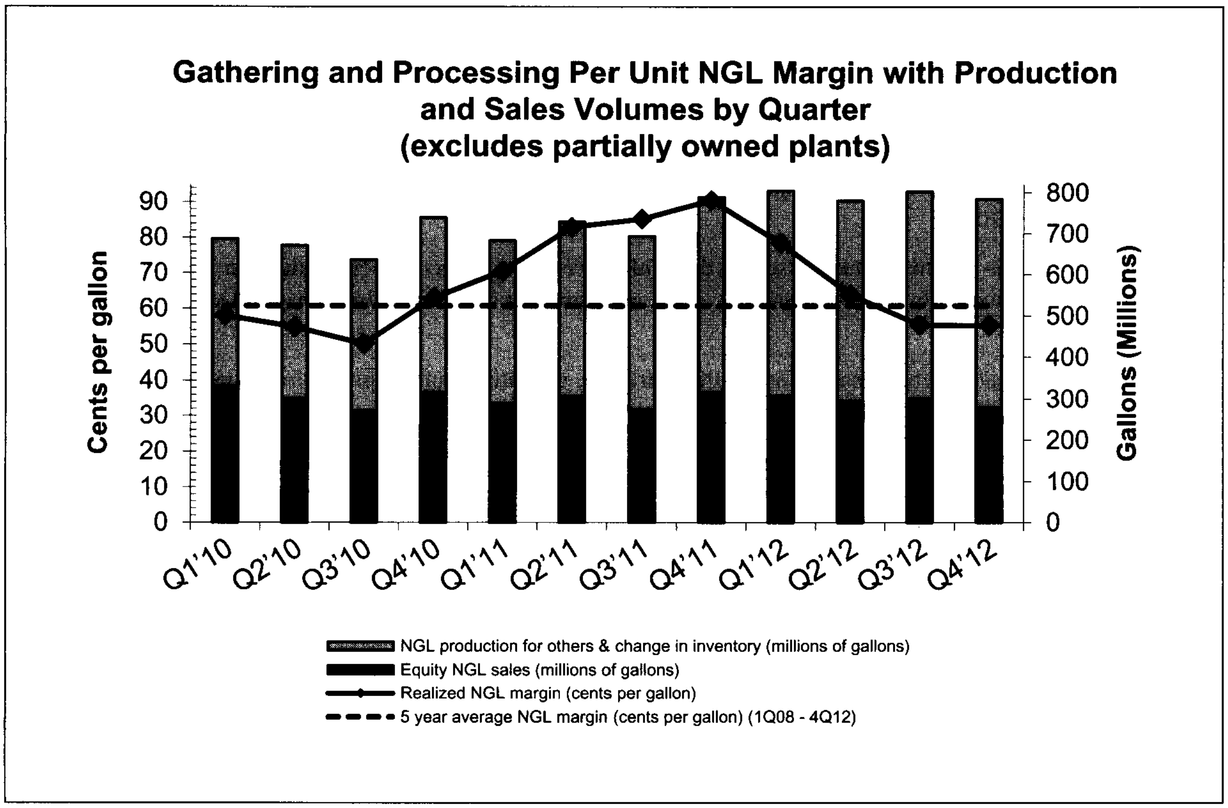
Our NGL equity sales volumes for the third quarter of 2012 were modestly impacted by maintenance on the Overland Pass Pipeline for approximately 5 days. As a result of the NGL pipeline maintenance, NGL takeaway capacity from our western plants on the Overland Pass Pipeline was reduced, which forced our western plants to reduce NGL recoveries.

In the Gulf Coast, our Mobile Bay plant was shut down for 10 days due to Hurricane Isaac. The plant and offshore platforms were evacuated during the storm. Afterwards, the plant remained shut down due to flooding issues on a third-party pipeline limiting the NGL takeaway capacity. In addition, production into Devils Tower was shut-in for various time periods due to third-party hurricane related issues. These events related to Hurricane Isaac did not have a material impact to our overall NGL production or NGL equity sales.

Volatile commodity prices

Driven primarily by a sharp decline in NGL prices during the second quarter of 2012, followed by increasing natural gas prices in the latter half of 2012, average per-unit NGL margins declined during 2012 and were approximately 23 percent lower in 2012 than in 2011. Because we typically realize lower per-unit margins for ethane versus other NGLs, if we had produced the same mix of ethane and non-ethane NGLs during the fourth quarter of 2012 as we generally have in prior periods, the average per-unit margin in the fourth quarter of 2012 would have been lower. Key factors in the NGL market weakness have been high propane inventories caused by the extremely warm winter and the effect of the propane oversupply on ethane inventories and pricing. Despite an increase in natural gas prices during the latter half of 2012, we have benefited from lower natural gas prices in 2012 than in 2011, driven by abundant natural gas supplies.

NGL margins are defined as NGL revenues less any applicable British thermal unit (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. Our equity volumes include NGLs where we own the rights to the value from NGLs recovered at our plants under both "keep-whole" processing agreements, where we have the obligation to replace the lost heating value with natural gas, and "percent-of-liquids" agreements whereby we receive a portion of the extracted liquids with no obligation to replace the lost heating value.



Outlook for 2013

The following factors, among others, could impact our business in 2013.

Commodity price changes

- We expect a decline in ethane and propane prices and an increase in natural gas prices such that our full year 2013 NGL margins are expected to be lower than our rolling five-year average and 2012 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, difficult to predict, and are often not highly correlated. 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.
- While per-unit ethylene margins are volatile and highly dependent upon continued demand within the global economy, we believe that our average per-unit ethylene margin will improve over 2012 levels, benefiting from higher ethylene prices and lower ethane and propane feedstock prices. 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.

Gathering, processing, and NGL sales volumes

- The growth of natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities, which are influenced by natural gas prices.
- We anticipate significant growth in our natural gas gathering volumes as our infrastructure grows to support drilling activities in the Marcellus Shale region.

- We anticipate equity NGL volumes in 2013 to be lower than 2012 due in part to a change in a customer's contract in the onshore business from percent-of-liquids to fee-based processing, with a portion of the fee representing a share of the associated NGL margins. We also expect lower equity NGL volumes due to periods when we expect it will not be economical to recover ethane. Our expectations of sustained low natural gas prices are expected to discourage producer drilling activities in the western onshore area and unfavorably impact the supply of natural gas available to gather and process in 2013.
- In Williams Partners' businesses in the Gulf Coast, we expect lower production handling and crude transportation volumes compared to 2012, as production flowing through our Devils Tower facility declines.
- We anticipate higher general and administrative, operating, and depreciation expense supporting our growing operations in the Marcellus Shale area.

Olefin production volumes

- We expect lower ethylene volumes in 2013 as compared to 2012 primarily due to major maintenance planned for 2013. With the completion of our Geismar expansion in the latter part of 2013, as discussed below, we expect growth in production volumes in the fourth quarter of 2013.

Expansion projects

We expect to invest total capital of $3.6 billion to $4.0 billion in 2013. The ongoing major expansion projects include the following:

Virginia Southside

In December 2012, we filed an application with the FERC to expand our existing natural gas transmission system from New Jersey to a proposed power station in Virginia and a delivery point in North Carolina. The capital cost of the project is estimated to be approximately $300 million. We plan to place the project into service in September 2015, which is expected to increase capacity by 270 Mdth/d.

Mid-South

In August 2011, we received approval from 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 $200 million. We placed the first phase of the project into service in September 2012, which increased capacity by 95 Mdth/d. We plan to place the second phase of the project into service in June 2013, which is expected to increase capacity by an additional 130 Mdth/d.

Rockaway Delivery Lateral

In January 2013, we filed an application with the FERC to construct a three-mile offshore lateral to a distribution system in New York. The capital cost of the project is estimated to be approximately $180 million. We plan to place the project into service during the second half of 2014, with an expected capacity of 647 Mdth/d.

Northeast Supply Link

In November 2012, we received approval from the FERC to expand our 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. The cost of the project is estimated to be $390 million and is expected to increase capacity by 250 Mdth/d. We plan to place the project into service in November 2013.

Marcellus Shale Expansions

- Expansion of our Susquehanna Supply Hub in northeastern Pennsylvania, as previously discussed.
- Expansions currently under construction to our natural gas gathering system, processing facilities and fractionator in our Ohio Valley Midstream business of the Marcellus Shale including a third turbo-expander at our Fort Beeler facility which is expected to add 200 MMcf/d of processing capacity in the first quarter of 2013. By the end of 2013, we expect our first turbo-expander at our Oak Grove facility to add 200 MMcf/d of processing capacity and additional fractionation capacity at our Moundsville fractionators bringing the NGL handling capacity to approximately 43 Mbbls/d.
- Expansions to our gathering system infrastructure through capital to be invested within our Laurel Mountain equity investment, also in the Marcellus Shale region.

Gulfstar FPS™ Deepwater Project

We will design, construct, and install our Gulfstar FPS™, a spar-based floating production system that utilizes a standard design approach with a capacity of 60 Mbbls/d of oil, up to 200 MMcf/d of natural gas, and the capability to provide seawater injection services. We expect Gulfstar FPS™ to be capable of serving as a central host facility for other deepwater prospects in the area. Construction is underway and the project is expected to be in service in 2014. In January 2013, WPZ agreed to sell a 49 percent ownership interest in its Gulfstar FPS™ project to a third party. The transaction is expected to close in second-quarter 2013, at which time we expect the third party will contribute $225 million to fund its proportionate share of the project costs, following with monthly capital contributions to fund its share of ongoing construction.

Parachute

In conjunction with a basin-wide agreement for all gathering and processing services provided by us to WPX in the Piceance basin, we plan to construct a 350 MMcf/d cryogenic natural gas processing plant. The Parachute TXP I plant is expected to be in service in 2014.

Geismar

An expansion of our Geismar olefins production facility is under way which is expected to increase the facility's ethylene production capacity by 600 million pounds per year to a new annual capacity of 1.95 billion pounds. The additional capacity will be wholly owned by us and is expected to increase our share of the Geismar production facility to over 88 percent. We expect to complete the expansion in the latter part of 2013.

Keathley Canyon Connector™

Our equity investee which we operate, Discovery, plans to construct, own, and operate a new 215-mile, 20-inch deepwater lateral pipeline from a third-party floating production facility located in the Keathley Canyon production area in the central deepwater Gulf of Mexico. Discovery has signed long-term agreements with anchor customers for natural gas gathering and processing services for production from the Keathley Canyon and Green Canyon areas. The Keathley Canyon Connector™ lateral will originate from a third-party floating production facility in the southeast portion of the Keathley Canyon area and will connect to Discovery's existing 30-inch offshore natural gas transmission system. The lateral pipeline is estimated to have the capacity to flow more than 400 MMcf/d and will accommodate the tie-in of other deepwater prospects. Pre-construction activities have begun; the pipeline is expected to be laid in 2013 and in service in mid-2014.

Overland Pass Pipeline Expansion

Through our equity investment in OPPL, we are participating in the construction of a pipeline connection and capacity expansions, expected to be complete in early 2013, to increase the pipeline's capacity to the maximum of 255 Mbbls/d, to accommodate new volumes coming from the Bakken Shale in the Williston basin.

Eminence Storage Field leak

On December 28, 2010, we detected a leak in one of the seven underground natural gas storage caverns at our Eminence Storage Field in Mississippi. Due to the leak and related damage to the well at an adjacent cavern, both caverns are out of service. In addition, two other caverns at the field, which were constructed at or about the same time as those caverns, have experienced operating problems, and we have determined that they should also be retired. The event has not affected the performance of our obligations under our service agreements with our customers.

In September 2011, we filed an application with the FERC seeking authorization to abandon these four caverns. In February 2013, the FERC issued an order approving the abandonment. We estimate the total abandonment costs, which will be capital in nature, will be approximately $92 million, which is expected to be spent through the end of 2013. As of December 31, 2012, we have incurred approximately $69 million in cumulative abandonment costs. This estimate is subject to change as work progresses and additional information becomes known. Management considers these costs to be prudent costs incurred in the abandonment of these caverns and expects to recover these costs, net of insurance proceeds, in future rate filings. To the extent available, the abandonment costs will be funded from the ARO Trust. (See Note 15 of Notes to Consolidated Financial Statements.)

Filing of rate cases

On August 31, 2012, Transco filed a general rate case with the FERC for an overall increase in rates. In September 2012, with the exception of certain rates that reflected a rate decrease, the FERC accepted and suspended our general rate filing to be effective March 1, 2013, subject to refund and the outcome of a hearing. We expect that our new rates, although still subject to refund until the rate case is resolved, will contribute to a modest increase in revenue in 2013. The specific rates that reflected a rate decrease were accepted, without suspension, to be effective October 1, 2012 and will not be subject to refund. The impact of these specific new rates that became effective October 1, 2012 is expected to reduce revenues by approximately $2 million for the period from January 1, 2013 until the remaining rates that are currently suspended become effective on March 1, 2013.

During the first quarter of 2012, Northwest Pipeline filed a Stipulation and Settlement Agreement with the FERC for an increase in their rates. Northwest Pipeline received FERC approval during the second quarter of 2012. The new rates, which as filed are 7.4 percent higher than the formerly applicable rates, became effective January 1, 2013.

Year-Over-Year Operating Results

	Year ended December 31,		
	2012	2011	2010
		(Millions)	
Segment revenues	$7,320	$7,714	$6,459
Segment profit	$1,812	$2,035	$1,666

2012 vs. 2011

The decrease in *segment revenues* includes:

- A $366 million decrease in revenues from our equity NGLs primarily reflecting a decrease of $354 million associated with an overall 26 percent decrease in average NGL per-unit sales prices. Average ethane and non-ethane per-unit prices decreased by 49 percent and 15 percent, respectively.
- A $77 million decrease in olefin sales revenues including $42 million lower ethylene production sales revenues primarily due to 10 percent lower average per-unit sales prices and $26 million lower propylene production sales revenues primarily due to 17 percent lower average per-unit sales prices.
- Marketing revenues are $93 million lower primarily due to a significant decrease in NGL and olefin prices, partially offset by higher NGL and crude volumes, as well as new volumes from natural gas marketing activities.
- A $39 million decrease in system management gas sales from our gas pipeline businesses (offset in segment costs and expenses).
- A $163 million increase in fee revenues primarily due to higher volumes in the Marcellus Shale, including new volumes on our recently acquired gathering and processing assets in our Ohio Valley Midstream and Susquehanna Supply Hub businesses; higher volumes in the western deepwater Gulf of Mexico, including higher volumes on our Perdido Norte natural gas and oil pipelines; and higher volumes in the Piceance basin.
- A $40 million increase in transportation revenues associated with natural gas pipeline expansion projects placed in service during 2011 and 2012.

The decrease in segment costs and expenses of $202 million includes:

- A $183 million decrease in olefin feedstock costs including $130 million lower ethylene feedstock costs driven by 38 percent lower average per-unit feedstock costs and $28 million lower propylene feedstock costs primarily due to 20 percent lower per-unit feedstock costs.
- A $137 million decrease in costs associated with our equity NGLs primarily due to a 31 percent decrease in average natural gas prices.
- A $39 million decrease in system management gas costs from our gas pipeline businesses (offset in *segment revenues*).
- A $46 million decrease in marketing purchases primarily due to significantly lower average NGL prices, partially offset by higher NGL and crude volumes, as well as new volumes from natural gas marketing activities. The changes in natural gas marketing purchases are more than offset by similar changes in natural gas marketing revenues.
- A $132 million increase in operating costs including higher depreciation and amortization of assets and intangibles, along with maintenance costs associated with assets acquired in 2012, partially offset by lower costs in our Four Corners area related to the consolidation of certain operations.
- An $81 million increase in general and administrative expenses including $23 million of Caiman and Laser acquisition and transition-related costs, as well as increases in employee-related and information technology expenses driven by general growth within our business operations.

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

- A $229 million decrease in NGL margins driven primarily by commodity price changes including lower NGL prices, partially offset by lower natural gas prices.
- A $132 million increase in operating costs as previously discussed.
- An $81 million increase in general and administrative expenses as previously discussed.

- A $47 million decrease in margins related to the marketing of NGLs primarily due to the impact of a significant and rapid decline in NGL prices, primarily during the second quarter of 2012, while product was in transit and a $7 million unfavorable change in write-downs of inventories to lower of cost or market. These unfavorable variances compare to periods of increasing prices during 2011.
- A $31 million decrease in equity earnings primarily due to $19 million lower Laurel Mountain equity earnings driven by lower gathering rates indexed to natural gas prices, higher operating costs, including depreciation, and the impairment of two minor NGL processing plants, partially offset by higher gathered volumes; $12 million lower Aux Sable equity earnings primarily due to lower NGL margins; and $12 million lower Discovery equity earnings primarily due to lower NGL margins and volumes. These decreases are partially offset by $11 million higher Gulfstream equity earnings primarily due to WPZ's acquisition of additional interest in Gulfstream, which was previously reflected in Other.
- A $163 million increase in fee revenues as previously discussed.
- A $106 million increase in olefin product margins including $88 million higher ethylene production margins primarily due to 38 percent lower average per-unit feedstock prices, partially offset by 10 percent lower average per-unit sales prices. DAC production margins were also $13 million higher, primarily resulting from higher average per-unit margins driven primarily by lower average per-unit feedstock prices.
- A $40 million increase in transportation revenues as previously discussed.

2011 vs. 2010

The increase in *segment revenues* includes:

- A $657 million increase in marketing revenues primarily due to higher average NGL, crude and propylene prices. These changes are substantially offset by similar changes in marketing purchases.
- A $244 million increase in revenues from our equity NGLs reflecting an increase of $272 million associated with a 25 percent increase in average NGL per-unit sales prices, partially offset by a decrease of $28 million associated with a 3 percent decrease in equity NGL volumes.
- A $167 million increase in olefin sales revenues including $126 million higher ethylene production sales revenues due to 28 percent higher average per-unit sales prices on 6 percent higher volumes primarily resulting from the absence of a four-week plant maintenance outage in 2010; and $30 million higher butadiene and DAC production sales revenues primarily due to higher average per-unit sales prices.
- A $107 million increase in fee revenues primarily due to higher gathering and processing fee revenues. We have fees from new volumes on our gathering assets in the Marcellus Shale in northeastern Pennsylvania, which we acquired at the end of 2010 and on our Perdido Norte gas and oil pipelines in the western deepwater Gulf of Mexico, which went into service in late 2010. In addition, higher fees in the Piceance basin are primarily a result of an agreement executed in November 2010. These increases are partially offset by a decline in gathering and transportation fees in the eastern deepwater Gulf of Mexico primarily due to natural field declines.
- A $68 million increase in transportation revenues associated with natural gas pipeline expansion projects placed in service in 2010 and 2011.

Segment costs and expenses increased $919 million including:

- A $641 million increase in marketing purchases primarily due to higher average NGL, crude and propylene prices. These changes are offset by similar changes in marketing revenues.
- A $117 million increase in olefin feedstock costs including $93 million higher ethylene feedstock costs resulting from higher average per-unit feedstock costs and 6 percent higher volumes and $11 million higher butadiene and DAC feedstock costs primarily due to higher per-unit feedstock costs.

- A $141 million increase in operating costs reflecting $90 million higher maintenance expenses, including maintenance expenses for our gathering assets in northeastern Pennsylvania acquired at the end of 2010, more maintenance performed on our assets in the western Onshore businesses, additional maintenance related to the Eminence storage leak, and higher property insurance expense. In addition, depreciation expense is $43 million higher primarily due to our new Perdido Norte pipelines and our Echo Springs expansion, both of which went into service in late 2010, along with increased depreciation of our Lybrook plant which was idled in January, 2012 when the gas was redirected to our Ignacio plant.
- The absence of $30 million in gains recognized in 2010 associated with sale of certain assets in Colorado's Piceance basin and involuntary conversion gains due to insurance recoveries in excess of the carrying value of certain Gulf Coast assets which were damaged by Hurricane Ike in 2008 and our Ignacio plant which was damaged by a fire in 2007.
- A $42 million decrease in costs associated with our equity NGLs reflecting a decrease of $21 million associated with a 5 percent decrease in average natural gas prices and a $21 million decrease reflecting lower equity NGL volumes.

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

- A $286 million higher NGL production margins reflecting favorable commodity price changes.
- A $107 million increase in fee revenues as previously discussed.
- A $68 million increase in transportation revenues associated with natural gas pipeline expansion projects placed in service in 2010 and 2011.
- A $50 million increase in olefin product margins including $33 million higher ethylene production margins due to 27 percent higher per-unit margins on 6 percent higher volumes and $19 million higher butadiene and DAC production margins primarily resulting from higher average per-unit margins.
- A $16 million increase in margins related to the marketing of NGLs, crude and propylene.
- A $33 million increase in equity earnings primarily due to the acquisition of additional interest in Gulfstream and an increased ownership interest in OPPL.
- A $141 million increase in operating costs as previously discussed.
- A $30 million unfavorable change primarily related to gains recognized in 2010 as previously discussed.

Williams NGL & Petchem Services

Our Williams NGL & Petchem Services segment includes our oil sands offgas processing plant near Fort McMurray, Alberta and our NGL/olefin fractionation facility and butylene/butane (B/B) splitter facility at Redwater, Alberta. We produce NGLs and propylene. Our NGL products include: propane, normal butane, isobutane/butylene (butylene), and condensate. Prior to the operation of the B/B splitter, which was placed into service in August 2010, we also produced and sold B/B mix product which is now separated and sold as butylene and normal butane.

Significant events for 2012

Boreal Pipeline

The Boreal Pipeline, which replaced third party transportation, was completed and placed into service in June 2012, requiring line fill that initially reduced volumes available for sale. The Boreal Pipeline is a 261-mile, 12-inch diameter pipeline in Canada that transports recovered NGLs and olefins from our extraction plant in Fort McMurray to our Redwater fractionation facility. The pipeline has an initial capacity of 43 Mbbls/d that can be increased to an ultimate capacity of 125 Mbbls/d with additional pump stations. The ultimate capacity provides sufficient capacity to transport additional recovered liquids in excess of those from our current agreements, including the anticipated ethane/ethylene mix resulting from ethane recovery projects expected to be placed into service in 2013.

Acquisition of liquids pipelines

In November 2012, we acquired 10 liquids pipelines in the Gulf Coast region. The acquired pipelines will be combined with an organic build-out of several projects to expand our petrochemical services in that region. The projects include the construction and commissioning of pipeline systems capable of transporting various products in the Gulf Coast region. The projects are expected to be placed into service beginning in late 2014.

Contribution of Gulf olefins production facilities

In November 2012, we contributed to WPZ our 83.3 percent interest and operatorship of the olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf region. Prior period segment disclosures have been recast for this transaction.

Outlook for 2013

The following factors could impact our business in 2013.

Commodity margin changes

While per-unit margins are volatile and highly dependent upon continued demand within the global economy, we believe that our gross commodity margins will be comparable or increase slightly over 2012 levels. 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 $390 million to $590 million in 2013 on capital projects. The major expansion projects include:

- The ethane recovery project, which is an expansion of our Canadian facilities that will allow us to recover ethane/ethylene mix from our operations that process offgas from the Alberta oil sands. We plan to modify our oil sands offgas extraction plant near Fort McMurray, Alberta, and construct a de-ethanizer at our Redwater fractionation facility. Our de-ethanizer is expected to initially process approximately 10,000 bbls/d of ethane/ethylene mix. We have signed a long-term contract to provide the ethane/ethylene mix to a third-party customer. We have begun construction and we expect to complete the expansions and begin producing ethane/ethylene mix in mid-year 2013.
- We have signed a long-term agreement to provide gas processing to a second bitumen upgrader in Canada's oils sands near Fort McMurray, Alberta. To support the new agreement, we plan to build a new liquids extraction plant, supporting facilities and an extension of the Boreal Pipeline to enable transportation of the NGL/olefins mixture to our Redwater facility. The NGL/olefins recovered are initially expected to be approximately 12,000 bbls/d by mid-2015. The NGL/olefins mixture will be fractionated at our Redwater facilities into an ethane/ethylene mix, propane, polymer grade propylene, normal butane, an alkylation feed and condensate. To mitigate the ethane price risk associated with this deal, we have a long-term supply agreement with a third party customer.
- As previously discussed, we will combine our new liquids pipelines with an organic build-out of several projects to expand our petrochemical services.

Year-Over-Year Operating Results

	Year ended December 31,		
	2012	2011	2010
		(Millions)	
Segment revenues	$279	$341	$238
Segment profit	$ 99	$157	$ 80

2012 vs. 2011

Segment revenues decreased primarily due to:

- $53 million lower NGL product sales revenues primarily due to 22 percent lower average per-unit sales prices.
- $12 million lower propylene product sales revenues primarily due to 22 percent lower average per-unit sales prices, partially offset by 10 percent higher sales volumes.

Segment costs and expenses decreased $4 million primarily as a result of $23 million lower NGL feedstock costs resulting from 25 percent lower average per-unit feedstock costs; substantially offset by the absence of $19 million of income related to the reduction of our accrual for the Gulf Liquids litigation in 2011 (See Note 17 of Notes to Consolidated Financial Statements.)

Segment profit decreased primarily due to:

- $30 million lower NGL product margins primarily due to 20 percent lower average per-unit margins.
- $12 million lower propylene product margins primarily due to 24 percent lower average per-unit margins on higher sales volumes.
- The absence of $19 million of income related to the reduction of our accrual for the Gulf Liquids litigation in 2011.

2011 vs. 2010

Segment revenues increased primarily due to:

- $79 million higher NGL production revenues primarily resulting from:
  - Higher average per-unit sales prices driven by a change in our Canadian product mix. Through mid-2010, we sold B/B mix product, but in August 2010, we began producing and selling both butylene and normal butane that was produced by our B/B splitter. The separated products receive higher values in the marketplace than the B/B mix sold previously.
  - Higher NGL sales prices resulting from higher market prices.
  - 29 percent increased sales volumes on our butylene and normal butane products primarily due to lower volume impact of operational and maintenance issues in 2011 as compared to 2010.
- $26 million higher propylene production revenues due to 30 percent higher average per-unit sales prices on 10 percent higher volumes primarily due to lower volume impact of operational and maintenance issues in 2011 as compared to 2010.

Segment costs and expenses increased $26 million primarily as a result of:

- $14 million higher operating and maintenance expenses primarily resulting from higher repairs and maintenance.

- $14 million higher NGL feedstock costs primarily due to higher average per-unit feedstock costs on certain products and increased volumes on our butylene and normal butane products primarily due to reduced maintenance and operational issues.
- $7 million higher costs relating to general and administrative expenses and asset retirements.
- The absence of a $6 million favorable customer settlement in 2010.

These increases were partially offset by $19 million of income related to the reduction of our accrual for the Gulf Liquids litigation in 2011.

Segment profit increased primarily due to:

- $42 million higher NGL production margins on the butylene and normal butane products primarily resulting from higher average per-unit margins primarily driven by a change in product mix, higher NGL sales prices, and higher volumes.
- $24 million higher propylene production margins resulting from 37 percent higher per-unit margins and 10 percent higher volumes.
- $23 million higher propane production margins due to 37 percent higher per-unit margins and 5 percent higher volumes.
- $19 million of income related to the reduction of our accrual for the Gulf Liquids litigation in 2011.

These increases were partially offset by $14 million higher operating and maintenance expenses, $7 million higher costs relating to general and administrative expenses and asset retirements, and the absence of a $6 million favorable customer settlement in 2010.

Access Midstream Partners

Our Access Midstream Partners segment includes our equity method investment in Access Midstream Partners. As of December 31, 2012, this investment includes a 24 percent limited partner interest in ACMP and a 50 percent indirect interest in Access GP, including incentive distribution rights. ACMP is a publicly traded master limited partnership that owns, operates, develops and acquires natural gas gathering systems and other midstream energy assets, which bolsters our position in the Marcellus and Utica shale plays and adds diversity via the Eagle Ford, Haynesville, Barnett, Mid-Continent, and Niobrara areas.

We acquired these interests in Access Midstream Partners on December 20, 2012, and the equity earnings recognized for the current period are insignificant.

Outlook for 2013

In conjunction with our investment in Access Midstream Partners in December 2012, Access Midstream Partners also completed the acquisition of the substantial majority of Chesapeake Energy's remaining midstream assets for approximately $2.16 billion. This acquisition significantly expanded the scale and geographic diversity of Access Midstream Partner's assets, which benefit from long-term fee-based contracts and extensive acreage dedications from producers. In addition to growth opportunities involving existing customers, Access Midstream Partners believes the scale of its operations in high-growth basins provides significant growth potential through business development. As a result of the stable cash flows from its businesses and the expected contribution from its recent acquisition, Access Midstream Partners expects its annual distributions to unitholders will grow by approximately 15 percent in 2013.

Considering the expected distribution growth from Access Midstream Partners, including the benefit we receive from our 50 percent indirect interest in Access GP and its incentive distribution rights, we expect to recognize growing equity earnings from our investment. Our earnings recognized, however, will be somewhat reduced by the non-cash amortization of the difference between the cost of our investment and our underlying share of the net assets of Access Midstream Partners. (See Notes 1 and 2 of Notes to Consolidated Financial Statements.)

Other

Other includes other business activities that are not operating segments as well as corporate operations.

Year-Over-Year Operating Results

	Year ended December 31,		
	2012	2011	2010
		(Millions)	
Segment revenues	$27	$25	$24
Segment profit	$49	$24	$68

2012 vs. 2011

The favorable change in *segment profit* is primarily due to $42 million of increased gains recognized related to the 2010 sale of our interest in Accroven SRL. As part of a settlement regarding certain Venezuelan assets in the first quarter of 2012, we received payment for all outstanding balances due from the sale. (See Note 4 of Notes to Consolidated Financial Statements.) The favorable change is partially offset by $12 million decreased equity earnings due to the contribution of a 24.5 percent interest in Gulfstream to WPZ in May 2011.

2011 vs. 2010

The unfavorable change in *segment profit* is primarily due to $32 million of decreased gains recognized in 2011 related to the 2010 sale of our interest in Accroven SRL and $21 million decreased equity earnings due to the contribution of the interest in Gulfstream in May 2011.

Management's Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2012, we continued to focus upon growth through disciplined investments. Examples of this growth included:

- Our investment in Access Midstream Partners;
- Williams Partners' Laser and Caiman Acquisitions;
- Continued investment in Williams Partners' gathering and processing capacity and infrastructure in the Marcellus Shale area, western United States, and deepwater Gulf of Mexico;
- Expansion of Williams Partners' interstate natural gas pipeline system to meet the demand of growth markets;

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

Outlook

We seek to manage our businesses with a focus on applying conservative financial policy and maintaining investment-grade credit metrics. Our plan for 2013 reflects our ongoing transition to an overall business mix that is increasingly fee-based. Although our cash flows are impacted by fluctuations in energy commodity prices, that impact is somewhat mitigated by certain of our cash flow streams that are not directly impacted by short-term commodity price movements, as follows:

- Firm demand and capacity reservation transportation revenues under long-term contracts from our gas pipelines;
- 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 capital and investment expenditures, dividends and distributions, working capital, and tax and debt interest payments while maintaining a sufficient level of liquidity. In particular, we note the following for 2013:

- We expect capital and investment expenditures to total between $3.975 billion and $4.575 billion in 2013. Of this total, maintenance capital expenditures, which are generally considered nondiscretionary and include expenditures to meet legal and regulatory requirements, to maintain and/or extend the operating capacity and useful lives of our assets, and to complete certain well connections, are expected to total between $355 million and $430 million. Expansion capital expenditures, which are generally more discretionary to fund projects in order to grow our business are expected to total between $3.62 billion and $4.145 billion. See Results of Operations — Segments, Williams Partners and Williams NGL & Petchem Services for discussions describing the general nature of these expenditures. In addition, we retain the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.
- We expect to pay total cash dividends of approximately $1.44 per common share, an increase of 20 percent over 2012 levels. We expect to increase our dividend quarterly through paying out substantially all of the cash distributions, net of applicable taxes, interest and costs, we receive from WPZ.
- We expect to fund capital and investment expenditures, tax and debt service payments, dividends and distributions, and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, utilization of our revolvers, and Williams and WPZ debt and/or equity securities as needed. Based on a range of market assumptions, we currently estimate our cash flow from operations will be between $2.075 billion and $2.55 billion in 2013.
- We expect to maintain consolidated liquidity (which includes liquidity at WPZ) of at least $1 billion from *cash and cash equivalents* and unused revolver capacity.

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 2013. Our internal and external sources of consolidated liquidity include cash generated from our operations, cash and cash equivalents on hand, and our revolvers. 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 revolver, and its access to capital markets. WPZ makes cash distributions to us in accordance with the partnership agreement, which considers our level of ownership and incentive distribution rights. As a result of our equity investment in Access Midstream Partners, we expect to receive quarterly cash distributions, based on 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.

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 Williams NGL & Petchem Services.

Available Liquidity	Expiration	December 31, 2012 WPZ	WMB	Total
			(Millions)	
Cash and cash equivalents		$ 20	$ 819(1)	$ 839
Available capacity under our $900 million revolver (2)	June 3, 2016		900	900
Capacity available to WPZ under its $2.4 billion revolver (3)	June 3, 2016	2,025		2,025
		$2,045	$1,719	$3,764

(1) Includes $531 million of *cash and cash equivalents* held primarily by certain international entities, that we intend to utilize to fund growth in our Canadian midstream operations and therefore, is not considered available for general corporate purposes. The remainder of our *cash and cash equivalents* is primarily held in government-backed instruments.

(2) At December 31, 2012, we are in compliance with the financial covenants associated with this revolver. (See Note 12 of Notes to Consolidated Financial Statements.)

(3) As of February 25, 2013, $975 million of loans are outstanding under this revolver. At December 31, 2012, WPZ is in compliance with the financial covenants associated with the WPZ revolver. The WPZ revolver is only available to WPZ, Transco and Northwest Pipeline as co-borrowers. (See Note 12 of Notes to Consolidated Financial Statements.)

In addition to the revolvers listed above, we have issued letters of credit totaling $27 million as of December 31, 2012, under certain bilateral bank agreements.

As described in Note 12 of Notes to Consolidated Financial Statements, we have determined that we have net assets that are technically considered restricted in accordance with Rule 4-08(e) of Regulation S-X of the Securities and Exchange Commission in excess of 25 percent of our consolidated net assets. We do not expect this determination will impact our ability to pay dividends or meet future obligations as the terms of WPZ's partnership agreement require it to make quarterly distributions of all available cash, as defined, to its unitholders.

Shelf Registrations

WPZ filed a shelf registration statement as a well-known, seasoned issuer in February 2012 to facilitate unlimited issuances 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 2012 to facilitate unlimited issuances of registered debt and equity securities.

Debt Offerings

In December 2012, we completed a public offering of $850 million of 3.7 percent senior unsecured notes due in 2023. We used the $842 million net proceeds to finance a portion of our investment in Access Midstream Partners.

In August 2012, WPZ completed a public offering of $750 million of its 3.35 percent senior unsecured notes due in 2022. WPZ used the $745 million net proceeds to repay outstanding borrowings under the WPZ revolver and for general partnership purposes.

In July 2012, Transco received net proceeds of $395 million from the issuance of $400 million of 4.45 percent senior unsecured notes due in 2042. These proceeds were used to repay Transco's $325 million 8.875 percent notes and for general corporate purposes, including capital expenditures.

Equity Offerings

In December 2012, we issued 46.5 million shares of common stock in a public offering at a price of $31.00 per share. We also sold an additional 7 million shares for $31.00 per share to the underwriters upon the underwriters' exercise of their option to purchase additional common shares. The net proceeds of $1.6 billion were used to fund the consideration for a portion of our investment in Access Midstream Partners, as well as related transaction expenses.

In August 2012, WPZ completed an equity issuance of 8,500,000 common units representing limited partner interests at a price of $51.43 per unit. Subsequently, WPZ sold an additional 1,275,000 common units for $51.43 per unit to the underwriters upon the underwriters' exercise of their option to purchase additional common units. The net proceeds of $488 million were used to repay outstanding borrowings under the WPZ revolver and for general partnership purposes.

In April 2012, we issued 30 million shares of common stock in a public offering at a price of $30.59 per share. We used the net proceeds of $887 million to fund a portion of the purchase of additional WPZ common units in connection with WPZ's Caiman Acquisition.

In April 2012, WPZ completed an equity issuance of 10,000,000 common units representing limited partner interests at a price of $54.56 per unit. Subsequently, WPZ sold an additional 973,368 common units for $54.56 per unit to the underwriters upon the underwriters' exercise of their option to purchase additional common units. The net proceeds of $581 million were used for general partnership purposes, including the funding of a portion of the cash purchase price of the Caiman Acquisition.

In January 2012, WPZ completed an equity issuance of 7,000,000 common units representing limited partner interests at a price of $62.81 per unit. In February 2012, WPZ sold an additional 1,050,000 common units for $62.81 per unit to the underwriters upon the underwriters' exercise of their option to purchase additional common units. The net proceeds of $490 million were used to fund capital expenditures and for general partnership purposes.

Acquisitions and Investments

In December 2012, we purchased an investment in Access Midstream Partners in exchange for approximately $2.19 billion in cash, including transaction costs.

In November 2012, WPZ completed the purchase of our 83.3 percent undivided interest and operatorship of the olefins production facility in Geismar, Louisiana, along with our refinery grade propylene splitter and pipelines in the Gulf region for total consideration of $2.364 billion. We received $25 million cash and 42,778,812 of WPZ common units. We have agreed to temporarily waive distributions otherwise due in respect of our incentive distribution rights (IDRs) of $16 million per quarter, beginning with the fourth quarter 2012 distribution until the later of December 31, 2013 or 30 days after the Geismar plant expansion is operational.

In April 2012, WPZ completed the Caiman Acquisition in exchange for aggregate consideration of $1.72 billion in cash, net of purchase price adjustments, and 11,779,296 of WPZ's common units. In connection with this acquisition, we made an additional investment in WPZ of $1 billion to facilitate the acquisition. We purchased 16,360,133 WPZ common units and have agreed to temporarily waive distributions otherwise due in respect of our IDRs related to these units and the units issued to the seller of Caiman Eastern Midstream, LLC, in connection with this acquisition, through 2013. The foregone IDRs would have yielded approximately $24 million in 2012.

In February 2012, WPZ completed the Laser Acquisition in exchange for $325 million in cash, net of cash acquired in the transaction, and 7,531,381 of WPZ's common units.

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:

	Rating Agency	Date of Last Change	Outlook	Senior Unsecured Debt Rating	Corporate Credit Rating
Williams:					
	Standard & Poor's	March 5, 2012	Stable	BBB-	BBB
	Moody's Investors Service	February 27, 2012	Stable	Baa3	N/A
	Fitch Ratings	February 9, 2012	Stable	BBB-	N/A
Williams Partners:					
	Standard & Poor's	March 5, 2012	Stable	BBB	BBB
	Moody's Investors Service	February 27, 2012	Stable	Baa2	N/A
	Fitch Ratings	February 9, 2012	Positive	BBB-	N/A

With respect to Standard and Poor's, a rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" indicates that the security has significant speculative characteristics. A "BB" rating indicates that Standard and 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 and Poor's may modify its ratings with a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

With respect to Moody's, a rating of "Baa" or above indicates an investment grade rating. A rating below "Baa" is considered to have speculative elements. 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 a ranking at the lower end of the category.

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

Credit rating agencies perform independent analyses when assigning credit ratings. No assurance can be given that the credit rating agencies will continue to assign us investment grade ratings even if we meet or exceed their current criteria for investment grade ratios. A downgrade of our credit rating might increase our future cost of borrowing and would require us to post additional collateral with third parties, negatively impacting our available liquidity. As of December 31, 2012, we estimate that a downgrade to a rating below investment grade for us or WPZ could require us to post up to $7 million or $429 million, respectively, in additional collateral with third parties.

Sources (Uses) of Cash

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 1,835	$ 3,439	$ 2,651
Financing activities	5,036	(342)	573
Investing activities	(6,921)	(3,003)	(4,296)
Increase (decrease) in cash and cash equivalents	$ (50)	$ 94	$(1,072)

Operating activities

Our *net cash provided by operating activities* in 2012 decreased from 2011 primarily due to the absence of cash flows from our former exploration and production business and lower operating results.

Our *net cash provided by operating activities* in 2011 increased from 2010 primarily due to higher operating income from our continuing businesses.

Financing activities

Significant transactions include:

2012

- $2.5 billion net proceeds received from our 2012 equity offerings;
- $1.559 billion received from WPZ's 2012 equity offerings;
- $842 million net proceeds received from our December 2012 public offering of $850 million 3.7 percent senior unsecured notes due 2023;
- $745 million net proceeds received from WPZ's August 2012 public offering of $750 million of senior unsecured notes due 2022;
- $395 million net proceeds received from Transco's July 2012 issuance of $400 million of senior unsecured notes;
- $1.49 billion received from WPZ revolver borrowings used for general partnership purposes, including capital expenditures;
- $1.115 billion of WPZ revolver borrowings paid;

- $325 million paid to retire Transco's 8.875 percent notes that matured in July 2012;
- We paid $742 million of quarterly dividends on common stock for the year ended December 31, 2012;
- We paid $387 million of dividends and distributions to noncontrolling interests;

2011

- $526 million of cash retained by WPX upon spin-off on December 31, 2011;
- $746 million of notes and debentures retired in December 2011 and $254 million paid in associated premiums;
- $1.5 billion received from WPX's issuance of senior unsecured notes in November 2011;
- $500 million received from WPZ's public offering of senior unsecured notes in November 2011 primarily used to repay borrowings on its credit facility mentioned below;
- $375 million received by Transco from the issuance of senior unsecured notes in August 2011;
- $300 million paid to retire Transco's senior unsecured notes that matured in August 2011;
- $300 million received in revolver borrowings from WPZ's $1.75 billion unsecured credit facility used for WPZ's acquisition of a 24.5 percent interest in Gulfstream from us in May 2011. This obligation was transferred to WPZ's new $2 billion unsecured credit facility at its inception in June 2011;
- $150 million paid to retire WPZ's senior unsecured notes that matured in June 2011;
- We paid $457 million of quarterly dividends on common stock for the year ended December 31, 2011;
- $425 million in net borrowings and payments related to WPZ's revolving credit facility;
- We paid $214 million of dividends and distributions to noncontrolling interests.

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 our former exploration and production business for WPZ's acquisition of certain gathering and processing assets in Colorado's Piceance basin;
- $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 2010 strategic restructuring;
- $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;

- $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;
- We paid $145 million of dividends and distributions to noncontrolling interests.

Investing activities

Significant transactions include:

2012

- Capital expenditures totaled $2.5 billion for 2012;
- Purchases of and contributions to our equity method investments were $2.7 billion, including $2.19 billion paid in December 2012 for our investment in Access Midstream Partners;
- $1.72 billion paid, net of purchase price adjustments, for WPZ's Caiman Acquisition in April 2012;
- $325 million paid, net of cash acquired in the transaction, for WPZ's Laser Acquisition in March 2012;
- $121 million received from the reconsolidation of the Wilpro entities. (See Note 3 of our Notes to Consolidated Financial Statements.) This cash is only considered available for use in our international operations;

2011

- Capital expenditures totaled $2.8 billion in 2011;
- We contributed $137 million to our Laurel Mountain equity investment.

2010

- Capital expenditures totaled $2.8 billion in 2010. Included is approximately $599 million, including closing adjustments, related to our former exploration and production business' acquisition in the Marcellus Shale in July 2010;
- We paid approximately $949 million, including closing adjustments, for our former exploration and production business' December 2010 business purchase, consisting primarily of oil and gas properties in the Bakken Shale;
- 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;
- We paid $150 million for WPZ's December 2010 business purchase, consisting primarily of certain midstream assets in the Marcellus Shale.

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

We have various other guarantees and commitments which are disclosed in Notes 10, 12, 16 and 17 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, 2012:

	2013	2014 - 2015	2016 - 2017	Thereafter	Total
			(Millions)		
Long-term debt, including current portion:					
Principal	$ —	$ 750	$1,535	$ 8,482	$10,767
Interest	575	1,123	1,008	4,751	7,457
Capital leases	1	1	—	—	2
Operating leases (1)	51	86	62	138	337
Purchase obligations (2)	1,675	273	215	504	2,667
Other long-term liabilities (3)(4)	1	1	—	1	3
Total	$2,303	$2,234	$2,820	$13,876	$21,233

(1) Includes a right-of-way agreement with the Jicarilla Apache Nation, which is considered an operating lease. We are required to make a fixed annual payment of $7.5 million and an additional annual payment, which varies depending on per-unit NGL margins and the volume of gas gathered by our gathering facilities subject to the right-of-way agreement. The table above for years 2014 and thereafter does not include such variable amounts related to this agreement as the variable amount is not yet determinable. The variable portion to be paid in 2013 based on 2012 gathering volumes is $7.3 million and is included in the table for year 2013.

(2) Includes approximately $1.3 billion in open property, plant and equipment purchase orders. Larger projects include Gulfstar and the Geismar plant expansion. Also includes an estimated $579 million long-term ethane purchase obligation with index-based pricing terms that is reflected in this table at December 31, 2012 prices. This obligation is part of an overall exchange agreement whereby volumes we transport on OPPL are sold at a third-party fractionator near Conway, Kansas, and we are subsequently obligated to purchase ethane volumes at Mont Belvieu. The purchased ethane volumes may be utilized or resold at comparable prices in the Mont Belvieu market. In addition, we have not included certain natural gas life-of-lease contracts for which the future volumes are indeterminable. We have not included commitments, beyond purchase orders, for the acquisition or construction of property, plant and equipment or expected contributions to our jointly owned investments (See Results of Operations — Segments).

(3) 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 $92 million in 2012 and $83 million in 2011. In 2013, we expect to contribute approximately $100 million to these plans (see Note 8 of Notes to Consolidated Financial Statements). Tax-qualified pension plans are required to meet minimum contribution requirements. In the past, we have contributed amounts to our tax-qualified pension plans in excess of the minimum required contribution. These excess amounts can be used to offset future minimum contribution requirements. During 2012, we contributed $70 million to our tax-qualified pension plans. In addition to these contributions, a portion of the excess contributions was used to meet the minimum contribution requirements. During 2013, we expect to contribute approximately $90 million to our tax-qualified pension plans and use excess amounts to satisfy minimum contribution requirements, if needed. 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.

(4) We have not included income tax liabilities in the table above. See Note 6 of Notes to Consolidated Financial Statements for a discussion of income taxes, including our contingent tax liability reserves.

Effects of Inflation

Our operations have historically not been materially affected by inflation. Approximately 52 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 17 of Notes to Consolidated Financial Statements). We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Current estimates of the most likely costs of such activities are approximately $46 million, all of which are included in *accrued liabilities* and *other noncurrent liabilities* on the Consolidated Balance Sheet at December 31, 2012. We will seek recovery of approximately $10 million of these accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2012, we paid approximately $7 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $12 million in 2013 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, 2012, certain assessment studies were still in process for which the ultimate outcome may yield 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.

In March 2008, the EPA promulgated a new, lower National Ambient Air Quality Standard (NAAQS) for ground-level ozone. 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 nonattainment 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. In September 2011, the EPA announced that it was proceeding with required actions to implement the 2008 ozone standard and area designations. In May 2012, the EPA completed designation of new eight-hour ozone non-attainment areas. Several Transco facilities are located in 2008 ozone nonattainment areas; however, each facility has been previously subjected to federal and/or state emission control requirements implemented to address preceding ozone standards. To date, no new federal or state actions have been proposed to mandate additional emission controls at these facilities. At this time, it is unknown whether future federal or state regulatory actions associated with implementation of the 2008 ozone standard will impact our operations and increase the cost of additions to *property, plant and equipment-net* on the Consolidated Balance Sheet. Until any additional federal or state regulatory actions are proposed, we are unable to estimate the cost of additions that may be required to meet this new regulation. Additionally, several non-attainment areas exist in or near areas where we have operating assets. States are required to develop implementation plans to bring these areas into compliance. Implementing regulations are expected to result in impacts to our operations and increase the cost of additions to *property, plant and equipment-net* on the Consolidated Balance Sheet for both new and existing facilities in affected areas.

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 capital costs in the range of $11 million to $13 million through 2013, the compliance date.

In June 2010, the EPA promulgated a final rule establishing a new one-hour sulfur dioxide (SO_2) NAAQS. The effective date of the new SO_2 standard was August 23, 2010. The EPA has not adopted final modeling guidance. We are unable at this time to estimate the cost of additions that may be required to meet this new regulation.

On January 22, 2010, the EPA set a new one-hour nitrogen dioxide (NO_2) NAAQS. The effective date of the new NO_2 standard was April 12, 2010. This standard is subject to challenge in federal court. On January 20, 2012, the EPA determined pursuant to available information that no area in the country is violating the 2010 NO_2 NAAQS and thus designated all areas of the country as "unclassifiable/attainment." Also, at that time the EPA noted its plan to deploy an expanded NO_2 monitoring network beginning in 2013. However on October 5, 2012, the EPA proposed a graduated implementation of the monitoring network between January 1, 2014 and January 1, 2017. Once three years of data is collected from the new monitoring network, the EPA will reassess attainment status with the one-hour NO_2 NAAQS. Until that time, the EPA or states may require ambient air quality modeling on a case by case basis to demonstrate compliance with the NO_2 standard. Because we are unable to predict the outcome of the EPA's or states' future assessment using the new monitoring network, we are unable to estimate the cost of additions that may be required to meet this 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. Our debt portfolio is primarily comprised of fixed rate debt, which mitigates 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. (See Note 12 of Notes to Consolidated Financial Statements.)

The tables below provide information by maturity date about our interest rate risk-sensitive instruments as of December 31, 2012 and 2011. 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.

	2013	2014	2015	2016	2017	Thereafter (1)	Total	Fair Value December 31, 2012
					(Millions)			
Long-term debt, including current portion (2):								
Fixed rate	$—	$—	$ 750	$375	$ 785	$8,449	$10,359	$12,013
Interest rate	5.5%	5.5%	5.6%	5.7%	5.6%	6.0%		
Variable rate	$—	$—	$—	$375	$—	$ —	$ 375	$ 375
Interest rate (3)								

	2012	2013	2014	2015	2016	Thereafter (1)	Total	Fair Value December 31, 2011
					(Millions)			
Long-term debt, including current portion (2):								
Fixed rate	$ 352	$—	$—	$750	$ 375	$7,241	$ 8,718	$10,043
Interest rate	6.0%	6.0%	6.0%	6.1%	6.2%	6.5%		

(1) Includes unamortized discount and premium.

(2) Excludes capital leases.

(3) The weighted average interest rate at December 31, 2012 was 2.7 percent.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of NGLs, olefins, and natural gas, 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 limited proprietary trading activities. Our management of the risks associated with these market fluctuations includes maintaining a conservative capital structure and significant liquidity, as well as 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 16 of Notes to Consolidated Financial Statements.)

We measure the risk in our portfolio using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolio. 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 portfolio. 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 portfolio will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

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

Trading

Our limited trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. At December 31, 2012, we had no trading derivatives in our portfolio. The fair value of our trading derivatives at December 31, 2011, was a net asset of less than $0.1 million. The value at risk for contracts held for trading purposes was zero at December 31, 2012, and less than $0.1 million at December 31, 2011.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from natural gas purchase and NGL purchase and sale activity. The fair value of our nontrading derivatives was a net asset of $4 million and $1 million at December 31, 2012, and 2011, respectively. The value-at-risk for derivative contracts held for nontrading purposes was less than $0.1 million at December 31, 2012, and zero at December 31, 2011. During the year ended December 31, 2012, our value at risk for these contracts ranged from a high of $2.3 million to a low of zero.

Certain of the derivative contracts held for nontrading purposes in 2012 were accounted for as cash flow hedges but realized during the year. As of December 31, 2012, the energy derivative contracts in our portfolio have not been designated as cash flow hedges.

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.

Foreign Currency Risk

Net assets of our consolidated foreign operations, whose functional currency is the local currency, located primarily in Canada were approximately $899 million and $779 million at December 31, 2012 and 2011, 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 *total stockholders' equity* by approximately $180 million at December 31, 2012.

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, 2012, 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, 2012, 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, 2012, 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, 2012, 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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2012, and our report dated February 27, 2013, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 27, 2013

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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedules listed in the index at Item 15(a). These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits. We did not audit the financial statements of Gulfstream Natural Gas System, L.L.C. (Gulfstream) (a limited liability corporation in which the Company has a 50 percent interest). The Company's investment in Gulfstream constituted one and two percent of the Company's assets as of December 31, 2012 and 2011, respectively, and the Company's equity earnings in the net income of Gulfstream constituted five, five, and seventeen percent of the Company's income from continuing operations before income taxes for the three years in the period ended December 31, 2012. Gulfstream's financial statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Gulfstream, is based solely on the report of the other auditors.

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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

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, 2012, 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 27, 2013, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the balance sheets of Gulfstream Natural Gas System, L.L.C., (the "Company"), as of December 31, 2012 and 2011, and the related statements of operations, comprehensive income, members' equity and cash flows for each of the three years in the period ended December 31, 2012. 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 audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits 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 audits provide 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, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 25, 2013

THE WILLIAMS COMPANIES, INC.
CONSOLIDATED STATEMENT OF OPERATIONS

	Years Ended December 31,		
	2012	2011	2010
	(Millions, except per-share amounts)		
Revenues:			
Service revenues	$ 2,729	$ 2,532	$ 2,359
Product sales	4,757	5,398	4,279
Total revenues	7,486	7,930	6,638
Costs and expenses:			
Product costs	3,496	3,934	3,260
Operating and maintenance expenses	1,027	990	870
Depreciation and amortization expenses	756	661	612
Selling, general, and administrative expenses	571	477	504
Other (income) expense — net	24	1	(15)
Total costs and expenses	5,874	6,063	5,231
Operating income (loss)	1,612	1,867	1,407
Equity earnings (losses)	111	155	143
Interest incurred	(568)	(598)	(628)
Interest capitalized	59	25	36
Other investing income — net	77	13	45
Early debt retirement costs	—	(271)	(606)
Other income (expense) — net	(2)	11	(12)
Income (loss) from continuing operations before income taxes	1,289	1,202	385
Provision (benefit) for income taxes	360	124	114
Income (loss) from continuing operations	929	1,078	271
Income (loss) from discontinued operations	136	(417)	(1,193)
Net income (loss)	1,065	661	(922)
Less: Net income attributable to noncontrolling interests	206	285	175
Net income (loss) attributable to The Williams Companies, Inc.	$ 859	$ 376	$ (1,097)
Amounts attributable to The Williams Companies, Inc.:			
Income (loss) from continuing operations	$ 723	$ 803	$ 104
Income (loss) from discontinued operations	136	(427)	(1,201)
Net income (loss)	$ 859	$ 376	$ (1,097)
Basic earnings (loss) per common share:			
Income (loss) from continuing operations	$ 1.17	$ 1.36	$ .17
Income (loss) from discontinued operations	.22	(.72)	(2.05)
Net income (loss)	$ 1.39	$ .64	$ (1.88)
Weighted-average shares (thousands)	619,792	588,553	584,552
Diluted earnings (loss) per common share:			
Income (loss) from continuing operations	$ 1.15	$ 1.34	$ .17
Income (loss) from discontinued operations	.22	(.71)	(2.03)
Net income (loss)	$ 1.37	$ .63	$ (1.86)
Weighted-average shares (thousands)	625,486	598,175	590,699

See accompanying notes.

THE WILLIAMS COMPANIES, INC.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)

(Millions)	Years Ended December 31, 2012	2011	2010
Net income (loss)	$1,065	$ 661	$ (922)
Other comprehensive income (loss):			
Cash flow hedging activities:			
Net unrealized gain (loss) from derivative instruments, net of taxes of ($7), ($152) and ($185) in 2012, 2011, and 2010	22	243	303
Reclassifications into earnings of net derivative instruments (gain) loss, net of taxes of $7, $124 and $131 in 2012, 2011, and 2010	(23)	(190)	(211)
Foreign currency translation adjustments	22	(18)	29
Pension and other postretirement benefits:			
Prior service credit (cost) arising during the year, net of taxes of ($1) and ($1) in 2012 and 2011	1	1	—
Amortization of prior service cost (credit) included in net periodic benefit cost, net of taxes of $1, $1 and $2 in 2012, 2011 and 2010	(1)	(2)	(2)
Net actuarial gain (loss) arising during the year, net of taxes of $19, $89 and $27 in 2012, 2011, and 2010	(30)	(152)	(56)
Amortization of actuarial (gain) loss included in net periodic benefit cost, net of taxes of ($22), ($16), and ($13) in 2012, 2011, and 2010	39	27	23
Equity securities:			
Unrealized gain (loss) on equity securities, net of taxes of ($2) in 2011	—	3	—
Reclassifications into earnings of (gain) loss on sale of equity securities, net of taxes of $2 in 2012	(3)	—	—
Other comprehensive income (loss)	27	(88)	86
Comprehensive income (loss)	1,092	573	(836)
Less: Comprehensive income (loss) attributable to noncontrolling interest	206	285	175
Comprehensive income (loss) attributable to The Williams Companies, Inc.	$ 886	$ 288	$(1,011)

See accompanying notes.

THE WILLIAMS COMPANIES, INC.
CONSOLIDATED BALANCE SHEET

	December 31, 2012	December 31, 2011
	(Millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 839	$ 889
Accounts and notes receivable (net of allowance of $0 at December 31, 2012 and $1 at December 31, 2011)	688	637
Deferred income tax asset	117	52
Inventories	175	169
Regulatory assets	39	40
Other current assets and deferred charges	66	107
Total current assets	1,924	1,894
Investments	3,987	1,391
Property, plant, and equipment — net	15,467	12,580
Goodwill	649	—
Other intangibles	1,704	44
Regulatory assets, deferred charges, and other	596	593
Total assets	$24,327	$16,502
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 920	$ 691
Accrued liabilities	628	631
Long-term debt due within one year	1	353
Total current liabilities	1,549	1,675
Long-term debt	10,735	8,369
Deferred income taxes	2,841	2,157
Other noncurrent liabilities	1,775	1,715
Contingent liabilities and commitments (Note 17)		
Equity:		
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 716 million shares issued at December 31, 2012 and 626 million shares issued at December 31, 2011)	716	626
Capital in excess of par value	11,134	7,920
Retained deficit	(5,695)	(5,820)
Accumulated other comprehensive income (loss)	(362)	(389)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders' equity	4,752	1,296
Noncontrolling interests in consolidated subsidiaries	2,675	1,290
Total equity	7,427	2,586
Total liabilities and equity	$24,327	$16,502

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 Income (Loss)	Treasury Stock	Total Stockholders' Equity	Noncontrolling Interest	Total
	(Millions)							
Balance, December 31, 2009	$618	$ 7,678	$ 903	$(168)	$(1,041)	$ 7,990	$ 572	$ 8,562
Net income (loss)	—	—	(1,097)	—	—	(1,097)	175	(922)
Other comprehensive income (loss)	—	—	—	86	—	86	—	86
Cash dividends — common stock (Note 13)	—	—	(284)	—	—	(284)	—	(284)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(145)	(145)
Issuance of common stock from debentures conversion (Note 13)	—	2	—	—	—	2	—	2
Stock-based compensation and related common stock issuances, net of tax	2	55	—	—	—	57	—	57
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	806	806
Changes in Williams Partners L.P. ownership interest, net	—	49	—	—	—	49	(77)	(28)
Balance, December 31, 2010	620	7,784	(478)	(82)	(1,041)	6,803	1,331	8,134
Net income (loss)	—	—	376	—	—	376	285	661
Other comprehensive income (loss)	—	—	—	(88)	—	(88)	—	(88)
Cash dividends — common stock (Note 13)	—	—	(457)	—	—	(457)	—	(457)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(214)	(214)
Issuance of common stock from debentures conversion (Note 13)	1	13	—	—	—	14	—	14
Stock-based compensation and related common stock issuances, net of tax	4	104	—	—	—	108	—	108
Changes in Williams Partners L.P. ownership interest, net	—	18	—	—	—	18	(30)	(12)
Distribution of WPX Energy, Inc. to stockholders (Note 3)	—	—	(5,261)	(219)	—	(5,480)	(81)	(5,561)
Other	1	1	—	—	—	2	(1)	1
Balance, December 31, 2011	626	7,920	(5,820)	(389)	(1,041)	1,296	1,290	2,586
Net income (loss)	—	—	859	—	—	859	206	1,065
Other comprehensive income (loss)	—	—	—	27	—	27	—	27
Cash dividends — common stock (Note 13)	—	—	(742)	—	—	(742)	—	(742)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(387)	(387)
Issuance of common stock from debentures conversion (Note 13)	1	5	—	—	—	6	—	6
Stock-based compensation and related common stock issuances, net of tax	6	98	—	—	—	104	—	104
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	1,559	1,559
Issuances of limited partner units of Williams Partners L.P. related to acquisitions	—	—	—	—	—	—	1,044	1,044
Changes in Williams Partners L.P. ownership interest, net	—	699	—	—	—	699	(1,115)	(416)
Sales of common stock (Note 13)	83	2,412	—	—	—	2,495	—	2,495
Reconsolidation of noncontrolling interest in Wilpro entities (Note 3)	—	—	—	—	—	—	65	65
Contributions to Constitution Pipeline Company, LLC (Note 1)	—	—	—	—	—	—	14	14
Other	—	—	8	—	—	8	(1)	7
Balance, December 31, 2012	$716	$11,134	$(5,695)	$(362)	$(1,041)	$ 4,752	$ 2,675	$ 7,427

See accompanying notes.

THE WILLIAMS COMPANIES, INC.
CONSOLIDATED STATEMENT OF CASH FLOWS

	2012	2011	2010
		Years Ended December 31, (Millions)	
OPERATING ACTIVITIES:			
Net income (loss)	$ 1,065	$ 661	$ (922)
Adjustments to reconcile to net cash provided (used) by operating activities:			
Depreciation, depletion, and amortization	756	1,614	1,507
Provision (benefit) for deferred income taxes	206	(179)	(155)
Provision for loss on goodwill, investments, property and other assets	—	882	1,735
Net (gain) loss on dispositions of assets	(52)	(1)	(82)
Gain on reconsolidation of Wilpro entities (Note 3)	(144)	—	—
Amortization of stock-based awards	36	52	48
Early debt retirement costs	—	271	606
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	27	(197)	(36)
Inventories	5	60	(81)
Other current assets and deferred charges	29	(15)	43
Accounts payable	(110)	250	(14)
Accrued liabilities	—	51	(29)
Other, including changes in noncurrent assets and liabilities	17	(10)	31
Net cash provided (used) by operating activities	1,835	3,439	2,651
FINANCING ACTIVITIES:			
Proceeds from long-term debt	3,486	3,172	5,129
Payments of long-term debt	(1,468)	(2,055)	(4,305)
Proceeds from issuance of common stock	2,550	49	12
Proceeds from sale of limited partner units of consolidated partnership	1,559	—	806
Dividends paid	(742)	(457)	(284)
Dividends and distributions paid to noncontrolling interests	(349)	(214)	(145)
Dividends paid to noncontrolling interests on sale of Wilpro assets (Note 3)	(38)	—	—
Cash of WPX Energy, Inc. at spin-off	—	(526)	—
Payments for debt issuance costs	(17)	(50)	(71)
Premiums paid on early debt retirements	—	(254)	(574)
Other — net	55	(7)	5
Net cash provided (used) by financing activities	5,036	(342)	573
INVESTING ACTIVITIES:			
Capital expenditures (1)	(2,529)	(2,796)	(2,788)
Purchases of and contributions to equity method investments	(2,651)	(211)	(488)
Purchases of businesses	(2,049)	(41)	(1,099)
Proceeds from dispositions of investments	79	16	46
Cash of Wilpro entities upon reconsolidation (Note 3)	121	—	—
Other — net	108	29	33
Net cash provided (used) by investing activities	(6,921)	(3,003)	(4,296)
Increase (decrease) in cash and cash equivalents	(50)	94	(1,072)
Cash and cash equivalents at beginning of year	889	795	1,867
Cash and cash equivalents at end of year	$ 839	$ 889	$ 795

	2012	2011	2010
(1) Increases to property, plant, and equipment	$(2,755)	$(2,953)	$(2,755)
Changes in related accounts payable and accrued liabilities	226	157	(33)
Capital expenditures	$(2,529)	$(2,796)	$(2,788)

See accompanying notes.

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

Description of Business

Our operations are located principally in the United States and are organized into the Williams Partners, Williams NGL & Petchem Services, previously referred to as Midstream Canada & Olefins, and Access Midstream Partners reportable segments. All remaining business activities are included in Other.

Williams Partners consists of our consolidated master limited partnership, Williams Partners L.P. (WPZ) and includes gas pipeline and domestic midstream businesses. The gas pipeline businesses primarily consist of 100 percent of Transcontinental Gas Pipe Line Company, LLC (Transco), 100 percent of Northwest Pipeline GP (Northwest Pipeline), 50 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream), and 51 percent of Constitution Pipeline Company, LLC (Constitution). WPZ's midstream operations are composed of significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, operations in the Marcellus Shale region, and various equity investments in domestic natural gas gathering and processing assets and natural gas liquid (NGL) fractionation and transportation assets. WPZ's midstream assets also include substantial operations and investments in the Four Corners region, the Piceance basin, an NGL fractionator and storage facilities near Conway, Kansas as well as an NGL light-feed olefins cracker in Geismar, Louisiana, along with associated ethane and propane pipelines, and a refinery grade splitter in Louisiana.

Williams NGL & Petchem Services includes a Canadian oil sands offgas processing plant located near Fort McMurray, Alberta, and an NGL/olefin fractionation facility and butylene/butane splitter facility at Redwater, Alberta.

Access Midstream Partners consists of our fourth-quarter 2012 purchase of an indirect equity interest in Access Midstream Partners, GP, L.L.C. (Access GP) and limited partner interests in Access Midstream Partners, L.P. (ACMP). ACMP is a publicly-traded master limited partnership that provides gathering, treating and compression services to producers under long-term, fee-based contracts. Access GP is the general partner of ACMP. (See Note 2).

Other includes other business activities that are not operating segments, as well as corporate operations.

Basis of Presentation

In November 2012, we contributed to WPZ our 83.3 percent undivided interest and operatorship of the olefins-production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf region for total consideration of 42,778,812 limited partner units of WPZ, $25 million in cash, and an increase in the capital account of its general partner to allow us to maintain our 2 percent general partner interest (Geismar Transaction). The operations of this business and the related assets and liabilities were previously reported in our Williams NGL & Petchem Services segment; however, they are now reported in our Williams Partners segment. Prior period segment disclosures have been recast for this transaction.

Following the Geismar Transaction, the Williams Partners segment includes operations related to the manufacture of olefin products. As a result, *revenues* within our Consolidated Statement of Operations are now presented as *service revenues* and *product sales.* We also revised the presentation of certain costs and operating expenses to align product costs with the presentation of our product sales. Costs and operating expenses has been separated into *product costs, operating and maintenance expenses,* and *depreciation and amortization expenses. Selling, general and administrative expenses* has also been combined with *general corporate expenses,* and depreciation and amortization expenses previously presented in *selling, general and administrative expenses* are now presented in *depreciation and amortization expenses.* All periods presented have been recast, along with corresponding information presented in the Notes to Consolidated Financial Statements, to reflect this change.

Certain prior period amounts reported within *total costs and expenses* in the Consolidated Statement of Operations have been reclassified to conform to the current presentation. The effect of the correction increased *operating and maintenance expenses* and decreased *selling, general, and administrative expenses*, with no net impact on *total costs and expenses*, *operating income (loss)* or *net income (loss)*. The adjustments were $14 million and $13 million in 2011 and 2010, respectively.

Consolidated master limited partnership

During the first quarter of 2012, WPZ completed a public equity issuance of 8,050,000 common units representing limited partner interests. WPZ also issued 7,531,381 common units to the seller in connection with its acquisition of certain entities from Delphi Midstream Partners, LLC. (See Note 2). During the second quarter of 2012, WPZ completed a public equity issuance of 10,973,368 common units representing limited partner interests. WPZ also issued 11,779,296 common units to the seller in connection with its acquisition of Caiman Eastern Midstream, LLC (See Note 2). In connection with the closing of this acquisition, we purchased 16,360,133 additional WPZ common units. In August 2012, WPZ completed a public equity issuance of 9,775,000 common units representing limited partner interests. Following these transactions, including the previously discussed limited partner units issued in the November 2012 Geismar Transaction, we own approximately 70 percent of the interests in WPZ, including the interests of the general partner, which are wholly owned by us, and incentive distribution rights as of December 31, 2012.

The previously described equity issuances by WPZ had the combined net impact of increasing our *noncontrolling interests in consolidated subsidiaries* by $1.488 billion, *capital in excess of par value* by $699 million and *deferred income taxes* by $416 million in the Consolidated Balance Sheet.

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.

Variable interest entities (VIEs)

We consolidate the activities of VIEs of which we are the primary beneficiary. The primary beneficiary of a VIE is the entity that has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits that could be significant to the VIE. As of December 31, 2012, WPZ has the following consolidated VIEs:

- Gulfstar One (Gulfstar) is a consolidated wholly-owned subsidiary that, due to certain risk sharing provisions in its customer contracts, is a VIE. WPZ, as construction agent for Gulfstar, will design, construct, and install a proprietary floating-production system, Gulfstar FPS™, and associated pipelines which will initially provide production handling and gathering services for the Tubular Bells oil and gas discovery in the eastern deepwater Gulf of Mexico. Construction is underway and the project is expected to be in service in 2014. WPZ, in combination with certain advance payments from the producer customers, is currently financing the asset construction. Gulfstar has construction work in process of $532 million and $103 million included in *property, plant, and equipment — net* as of December 31, 2012 and 2011, respectively, $109 million and $101 million of deferred revenue associated with customer advance payments included in *other noncurrent liabilities* as of December 31, 2012 and 2011, respectively, and $124 million and $33 million of *accounts payable* as of December 31, 2012 and 2011, respectively in the Consolidated Balance Sheet. We are committed to the producer customers to construct this system, and we currently estimate the remaining construction cost to be less than $475 million. If the producer customers do not develop the offshore oil and gas fields to be connected to Gulfstar, they will be responsible for the firm price of building the facilities. In January 2013, WPZ agreed to sell a 49 percent ownership interest in its Gulfstar FPS™ project to a third party. The transaction is expected to close in second-quarter 2013, at which time we expect the third party will contribute $225 million to fund its proportionate share of the project costs, following with monthly contributions to fund its share of ongoing construction.

- WPZ owns a 51 percent interest in Constitution, a subsidiary that, due to shipper fixed payment commitments under its firm transportation contracts, is a VIE. WPZ is the primary beneficiary because it has the power over the decisions that most significantly impact Constitution's economic performance. WPZ, as construction agent for Constitution, will build a pipeline connecting our gathering system in Susquehanna County, Pennsylvania to the Iroquois Gas Transmission and the Tennessee Gas Pipeline systems. WPZ plans to place the project in service in March 2015 and estimates the total cost of the project to be approximately $680 million, which will be funded with capital contributions from us, along with the other equity partners, proportional to ownership interest. As of December 31, 2012, the Consolidated Balance Sheet includes $8 million of *cash and cash equivalents*, $24 million of Constitution construction work in progress representing costs incurred to date, included in *property, plant and equipment — net* and $4 million of *accounts payable*.

WPZ has also identified certain interests in VIEs where it is not the primary beneficiary. These include WPZ's investments in Laurel Mountain Midstream, LLC (Laurel Mountain) and Discovery Producer Services LLC (Discovery). These entities are considered to be VIEs generally due to contractual provisions that transfer certain risks to customers. As certain significant decisions in the management of these entities require a unanimous vote of all members, WPZ is not the primary beneficiary. Our maximum exposure to loss is limited to the carrying value of our investments. (See Note 4).

Discontinued operations

On December 31, 2011, we completed the tax-free spin-off of our 100 percent interest in WPX Energy, Inc. (WPX), to our stockholders. The spin-off was completed by means of a special stock dividend, which consisted of a distribution of one share of WPX common stock for every three shares of our common stock. For periods prior to the spin-off, the accompanying Consolidated Statement of Operations reflects the results of operations of our former exploration and production business as discontinued operations. The Consolidated Statement of Comprehensive Income (Loss) for 2011 and 2010 and the Consolidated Statement of Cash Flows for 2011 and 2010 includes the results of our former exploration and production business. (See Note 3.)

Unless indicated otherwise, the information in the Notes to 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 and 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 and 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.

Equity method investment basis differences

Differences between the cost of our equity investments and our underlying equity in the net assets of investees are accounted for as if the investees were consolidated subsidiaries. *Equity earnings (losses)* in the Consolidated Statement of Operations includes our allocable share of net income (loss) of investees adjusted for any depreciation and amortization, as applicable, associated with basis differences.

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, property, plant and equipment, goodwill, and other identifiable intangible assets;
- Litigation-related contingencies;
- Environmental remediation obligations;
- Realization of deferred income tax assets;
- Depreciation and/or amortization of equity method investment basis differences;
- Asset retirement obligations;
- Pension and postretirement valuation variables;
- Acquisition related purchase price allocations.

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 nonregulated businesses. The components of our regulatory assets and liabilities relate to the effects of deferred taxes on equity funds used during construction, asset retirement obligations, fuel cost differentials, levelized incremental depreciation, negative salvage, and postretirement benefits. We have regulatory assets of $405 million and $411 million at December 31, 2012 and 2011, respectively and regulatory liabilities of $265 million and $206 million at December 31, 2012 and 2011, respectively in the Consolidated Balance Sheet.

Cash and cash equivalents

Cash and cash equivalents 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 condition of our customers, and the amount and age of past due accounts. We consider receivables 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.

Property, plant, and equipment

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

As regulated entities, Northwest Pipeline and Transco provide for depreciation using the straight-line method at FERC-prescribed rates. Depreciation for nonregulated entities is provided primarily on the straight-line method over estimated useful lives, except for certain offshore facilities that apply a declining balance method. (See Note 10.)

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 (loss)* or *other income (expense) — net* below *operating income (loss).*

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

We record an asset and a liability equal to the present value of each expected future asset retirement obligation (ARO) at the time the liability is initially incurred, typically when the asset is acquired or constructed. The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. As regulated entities, Northwest Pipeline and Transco record the ARO asset depreciation offset to a regulatory 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 *operating and maintenance expenses*, 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 cost over fair value of the assets of businesses acquired. It is not subject to amortization but is evaluated annually as of October 1 for impairment or more frequently if impairment indicators are present. Our evaluation includes an assessment of events or circumstances to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount. If so, we further compare our estimate of the fair value of the reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess. We have *goodwill* of $649 million at December 31, 2012 in the Consolidated Balance Sheet attributable to our Williams Partners segment.

Other Intangible Assets

Our identifiable intangible assets are primarily related to gas gathering, processing and fractionation contracts and relationships with customers. We have *other intangibles* of $1.704 billion and $44 million at December 31, 2012 and 2011, respectively in the Consolidated Balance Sheet primarily attributable to our Williams Partners segment. Our intangible assets are amortized on a straight-line basis over estimated useful lives. We evaluate these assets for changes in the expected remaining useful lives and would reflect any changes prospectively through amortization over the revised remaining useful life.

Impairment of property, plant, and equipment, other identifiable intangible assets, and investments

We evaluate our property, plant, and equipment and other identifiable intangible assets for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our management's estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred and we may 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. This evaluation is performed at the lowest level for which separately identifiable cash flows exist.

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.

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 or investment's fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal.

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. These liabilities are calculated based upon our assumptions and estimates with respect to the likelihood or amount of loss and upon advice of legal counsel, engineers, or other third parties regarding the probable outcomes of the matters. These calculations are made without consideration of any potential recovery from third-parties. We recognize insurance recoveries or reimbursements from others when realizable. Revisions to these liabilities are generally reflected in income when new or different facts or information become known or circumstances change that affect the previous assumptions or estimates.

Cash flows from revolving credit facilities

Proceeds and payments related to borrowings under our credit facilities are reflected in the financing activities in 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 may utilize derivatives to manage a portion of our commodity price risk. These instruments consist primarily of swaps, futures, and forward contracts involving short- and long-term purchases and sales of physical energy commodities. We report the fair value of derivatives, except for those for which the normal purchases and normal sales exception has been elected, in *other current assets and deferred charges; regulatory assets, deferred charges, and other; accrued liabilities;* or *other noncurrent liabilities.* 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 physical energy commodities. 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 may also designate 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 *product sales* or *product costs*.

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 *product sales* or *product costs*. 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 *product sales* or *product costs* at that time. The change in likelihood of a forecasted transaction 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 *product sales* or *product costs*.

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 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

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.

Service revenues

Revenues from our gas pipeline businesses include 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.

Certain revenues from our midstream operations include those derived from natural gas gathering and processing services and are performed under volumetric-based fee contracts. These revenues are recorded when services have been performed.

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.

Storage revenues from our midstream operations associated with prepaid contracted storage capacity contracts are recognized on a straight-line basis over the life of the contract as services are provided.

Product sales

In the course of providing transportation services to customers of our gas pipeline businesses, 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.

We market NGLs, crude oil, natural gas, and olefins that we purchase from our producer customers as part of the overall service provided to producers. Revenues from marketing NGLs are recognized when the products have been sold and delivered.

Under our 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.

Our domestic olefins business produces olefins from purchased feed-stock and we recognize revenues when the olefins are sold and delivered.

Our midstream Canada business has processing and fractionation operations where we retain certain NGLs and olefins from an upgrader's offgas stream and we recognize revenues when the fractionated products are sold and delivered.

Interest capitalized

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. The latter is included in *other income (expense) — net* below *operating income (loss).* The rates used by regulated companies are calculated in accordance with FERC rules. Rates used by nonregulated companies are based on our average interest rate on debt.

Employee stock-based awards

We recognize compensation expense on employee stock-based awards, net of estimated forfeitures, on a straight-line basis. (See Note 14.)

Income taxes

We include the operations of our domestic corporate subsidiaries and income from our domestic subsidiary partnerships 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 when the transactions are settled result in transaction gains and losses which are reflected in the Consolidated Statement of Operations.

Note 2. Acquisitions

Business Combinations

On February 17, 2012, WPZ completed the acquisition of 100 percent of the ownership interests in certain entities from Delphi Midstream Partners, LLC, in exchange for $325 million in cash, net of cash acquired in the transaction, and 7,531,381 WPZ common units valued at $441 million (Laser Acquisition). The fair value of the common units issued as part of the consideration paid was determined on the basis of the closing market price of WPZ's common units on the acquisition date, adjusted to reflect certain time-based restrictions on resale. The acquired entities primarily own the Laser Gathering System, which is comprised of 33 miles of 16-inch natural gas pipeline and associated gathering facilities in the Marcellus Shale in Susquehanna County, Pennsylvania, as well as 10 miles of gathering lines in southern New York.

On April 27, 2012, WPZ completed the acquisition of 100 percent of the ownership interests in Caiman Eastern Midstream, LLC, from Caiman Energy, LLC in exchange for $1.72 billion in cash, subject to the final purchase price adjustment, and 11,779,296 WPZ common units valued at $603 million (Caiman Acquisition). The fair value of the common units issued as part of the consideration paid was determined on the basis of the closing market price of WPZ's common units on the acquisition date, adjusted to reflect certain time-based restrictions on resale. The acquired entity operates a gathering and processing business in northern West Virginia, southwestern Pennsylvania and eastern Ohio. Acquisition transaction costs of $16 million were incurred related to the Caiman Acquisition and are reported in *selling, general and administrative expenses* at Williams Partners in the Consolidated Statement of Operations.

These acquisitions were accounted for as business combinations which, among other things, require assets acquired and liabilities assumed to be measured at their acquisition-date fair values. The excess of cost over those fair values was recorded as goodwill and allocated to our midstream businesses (the reporting unit) within the Williams Partners segment. Goodwill recognized in the acquisitions relates primarily to enhancing our strategic platform for expansion in the Marcellus and Utica shale plays in the Appalachian basin area. Substantially all of the goodwill is expected to be deductible for tax purposes. The amount recorded for goodwill in the Caiman Acquisition is preliminary pending final determination of the purchase price adjustment.

The following table presents the allocation of the acquisition-date fair value of the major classes of the net assets, which are included in the Williams Partners segment:

	Laser	Caiman
	(Millions)	
Assets held-for-sale	$ 18	$ —
Other current assets	3	16
Property, plant and equipment	158	656
Intangible assets:		
Customer contracts	316	1,141
Customer relationships	—	250
Other intangible assets	2	2
Current liabilities	(21)	(94)
Noncurrent liabilities	—	(3)
Identifiable net assets acquired	476	1,968
Goodwill	290	359
	$766	$2,327

Identifiable intangible assets recognized in the Laser and Caiman Acquisitions are primarily related to gas gathering, processing and fractionation contracts and relationships with customers. The basis for determining the value of these intangible assets is estimated future net cash flows to be derived from acquired customer contracts and relationships, which are offset with appropriate charges for the use of contributory assets and discounted using a risk-adjusted discount rate. Those intangible assets are being amortized on a straight-line basis over an initial 30-year period which represents a portion of the term over which the customer contracts and relationships are expected to contribute to our cash flows.

We expense costs incurred to renew or extend the terms of our gas gathering, processing and fractionation contracts with customers. Approximately 70 percent and 36 percent of the expected future revenues from the customer contracts associated with the Laser and Caiman Acquisitions, respectively, are impacted by our ability and intent to renew or renegotiate existing customer contracts. Based on the estimated future revenues during the current contract periods, the weighted-average periods prior to the next renewal or extension of the existing customer contracts associated with the Laser and Caiman Acquisitions are approximately 9 years and 18 years, respectively.

Revenues and earnings related to the Laser and Caiman Acquisitions included within the Consolidated Statement of Operations since the respective acquisition dates are not material. Supplemental pro forma revenue and earnings reflecting these acquisitions as if they had occurred as of January 1, 2011, are not materially different from the information presented in our accompanying Consolidated Statement of Operations (since the historical operations of these acquisitions were insignificant relative to our historical operations) and are, therefore, not presented.

Amortization of Other Intangible Assets

Amortization expense related to *other intangibles* was $43 million, $2 million and zero in 2012, 2011, and 2010, respectively. Accumulated amortization related to *other intangibles* was $45 million and $2 million at December 31, 2012 and 2011, respectively. The estimated amortization expense for each of the next five succeeding fiscal years is approximately $58 million.

Purchase of Investment

On December 20, 2012, we purchased an indirect interest in Access GP and limited partner interests in ACMP (collectively referred to as Access Midstream Partners) for approximately $2.19 billion in cash, including transaction costs. We now own a 50 percent interest in Access Midstream Ventures, L.L.C., which owns Access GP and its 2 percent general partner interest in ACMP and incentive distribution rights. In addition, we hold approximately 24 percent of ACMP's outstanding limited partnership units, for a combined ownership interest of approximately 25 percent of ACMP. ACMP is a publicly traded master limited partnership listed on the New York Stock Exchange that owns, operates, develops and acquires natural gas gathering systems and other midstream energy assets, which bolsters our position in the Marcellus and Utica shale plays and adds diversity via the Eagle Ford, Haynesville, Barnett, Mid-Continent and Niobrara areas.

We account for these acquired interests as equity method investments. The difference between the cost of our investment and our proportional share of the underlying equity in the net assets of Access Midstream Partners of $1.27 billion is primarily related to property, plant and equipment, as well as customer-based intangible assets and goodwill. The portions of the difference related to the property, plant and equipment and customer-based intangible assets are being depreciated or amortized as appropriate on a straight-line basis as an adjustment to our equity earnings from the investment in Access Midstream Partners over a weighted-average period of approximately 18 years.

Our investment in Access Midstream Partners is disclosed as a separate reportable segment. See Note 18 for the segment disclosures.

Note 3. Discontinued Operations

On December 31, 2011, we completed the tax-free spin-off of our 100 percent interest in WPX to our stockholders. (See Note 1.) At December 31, 2011, the net assets of our former exploration and production business were eliminated from our consolidated balance sheet as the spin-off was complete.

The following summarized results of discontinued operations for 2012 primarily include a gain on reconsolidation following the sale of certain of our former Venezuela operations, whose facilities were expropriated by the Venezuelan government in May 2009. The summarized results of discontinued operations for 2011 and 2010 reflect the results of operations of our former exploration and production business as discontinued operations.

Summarized Results of Discontinued Operations

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Revenues	$—	$3,997	$ 4,042
Income (loss) from discontinued operations before gain on reconsolidation, impairments and income taxes	$(16)	$ 223	$ 350
Gain on reconsolidation	144	—	—
Impairments	—	(755)	(1,682)
(Provision) benefit for income taxes	8	115	139
Income (loss) from discontinued operations	$136	$ (417)	$(1,193)
Income (loss) from discontinued operations:			
Attributable to noncontrolling interests	$—	$ 10	$ 8
Attributable to The Williams Companies, Inc.	$136	$ (427)	$(1,201)

Revenues and *income (loss) from discontinued operations before gain on reconsolidation, impairments and income taxes* for 2011 and 2010 primarily reflects the results of operations of our discontinued exploration and production business. Results for 2011 additionally include $42 million of transaction costs related to the spin-off.

Gain on reconsolidation for 2012 is related to our majority ownership in entities (the Wilpro entities) that owned and operated the El Furrial and PIGAP II gas compression facilities prior to their expropriation by the Venezuelan government in May 2009. We deconsolidated the Wilpro entities in 2009. In the first quarter of 2012, the El Furrial and PIGAP II assets were sold as part of a settlement related to the 2009 expropriation of these assets. Upon closing, the lenders that had provided financing for these operations were repaid in full, and the Wilpro entities received $98 million in cash and the right to receive quarterly cash installments of $15 million (receivable) through the first quarter of 2016 plus interest. Following the settlement and repayment in full of the lenders, we reestablished control and, therefore, reconsolidated the Wilpro entities and recognized a gain on reconsolidation of $144 million. This gain reflects our share of the cash, including cash received in the settlement, and a receivable held by the Wilpro entities at the time of reconsolidation. The receivable was recognized at its estimated fair value, as further described below.

To determine the fair value of the receivable at the time of reconsolidation, we considered both quantitative (income) and qualitative (market) approaches. Under our quantitative approach, we calculated the net present value of a probability-weighted set of cash flows utilizing assumptions based on contractual terms, historical payment patterns by the counterparty under similar circumstances, our likelihood of using arbitration if the counterparty does not perform, and discount rates. Our qualitative analysis utilized information as to how similar notes might be valued. This analysis also reduced the value due to its limited marketability as the payment terms are embedded within the overall settlement agreement. Both analyses resulted in similar fair values. Ultimately we determined the fair value of the receivable to be $88 million at the time of reconsolidation, utilizing a probability-weighted cash flow analysis with a discount rate of approximately 12 percent and a probability of default ranging from 15 percent to 100 percent. Utilizing different assumptions regarding the collectability of the receivable and discount rates could have resulted in a materially different fair value. See Note 15 for a further discussion of this receivable.

Impairments in 2011 reflect $367 million and $180 million of impairments of capitalized costs of certain natural gas producing properties of our discontinued exploration and production business in the Powder River basin and the Barnett Shale, respectively, $29 million of write-downs to estimates of fair value less costs to sell the assets of our discontinued exploration and production business in the Arkoma basin, and an impairment of $179 million in connection with the spin-off of WPX to reflect the difference between the carrying value of our investment in WPX and the estimated fair value of WPX at the time of spin-off. (See further discussion below regarding the determination of the fair value of WPX.) These nonrecurring fair value measurements fell within Level 3 of the fair value hierarchy.

Impairments in 2010 include a $1,003 million impairment of domestic goodwill (to an implied fair value of zero at the assessment date) and $678 million of impairments of capitalized costs of certain natural gas producing properties in the Barnett Shale and acquired unproved reserves in the Piceance basin of our discontinued exploration and production business (to their estimated fair value of $320 million at the assessment date). These nonrecurring fair value measurements fell within Level 3 of the fair value hierarchy.

For the goodwill evaluation, we used an income approach (discounted cash flow) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves included estimated reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates.

For our assessment of the carrying value of our natural gas producing properties and costs of acquired unproved reserves, we utilized estimates of future cash flows, in certain cases including purchase offers received. 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.

(Provision) benefit for income taxes for 2011 includes a $26 million net tax benefit associated with the write-down of certain indebtedness related to our former power operations.

Impairment of our investment in WPX

In conjunction with accounting for the spin-off of WPX, we evaluated whether there was an indicator of impairment of the carrying value of the investment at the date of the spin-off. Because the market capitalization of WPX as determined by its closing stock price on December 30, 2011, pursuant to the "when issued" trading market was less than our investment in WPX, we determined that an indicator of impairment was present and conducted an evaluation of the fair value of our investment in WPX at the date of the spin-off.

To determine the fair value at the time of spin-off, we considered several valuation approaches to derive a range of fair value estimates. These included consideration of the "when issued" stock price at December 30, 2011, an income approach, and a market approach. While the "when issued" stock price approach utilized the most observable inputs of the three approaches, we noted that the short trading duration, low trading volumes and lack of liquidity in the "when issued" market, among other factors, served to limit this input in being solely determinative of the fair value of WPX. As such, we also considered the other valuation approaches in estimating the overall fair value of WPX, though giving preferential weighting to the "when issued" stock price approach.

Key variables and assumptions included the application of a control premium of up to 30 percent to the December 30, 2011 "when issued" trading value based on transactions involving energy companies. For the income approach, we estimated the fair value of WPX using a discounted cash flow analysis of their oil and natural gas reserves, primarily adjusted for long-term debt. Implicit in this approach was the use of forward market prices and discount rates that considered the risk of the respective reserves. After-tax discount rates assumed to be used by market participants were an average of 11.25 percent for proved reserves, 13.25 percent to 15.25 percent for probable reserves, and 15.25 percent to 18.25 percent for possible reserves. For the market approach, we considered multiples of cash flows derived from the value of comparable companies utilizing their respective traded stock prices, adjusted for a control premium consistent with levels noted above. Using these methodologies, we computed a range of estimated fair values from $4.5 billion to $6.7 billion. After giving preferential weighting to the "when issued" valuation, we computed an estimated fair value of approximately $5.5 billion.

As a result of this evaluation, we recorded an impairment charge which is nondeductible for tax purposes. This amount served to reduce the investment basis of the net assets accounted for as a dividend upon the spin-off at December 31, 2011.

Energy Commodity Derivatives Gains and Losses

The following table presents pre-tax gains and losses for our former exploration and production business' energy commodity derivatives.

	Year ended December 31, 2011	Classification
	(Millions)	
Designated as cash flow hedges		
Net gain (loss) recognized in other comprehensive income (loss) (effective portion)	$413	AOCI
Net gain (loss) reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$332	Income (loss) from discontinued operations
Not designated as cash flow hedges		
Gain (loss) recognized in income	$ 30	Income (loss) from discontinued operations

Note 4. Investing Activities

Investing Income

	Years Ended December 31, 2012	2011	2010
		(Millions)	
Equity earnings (losses) (1)	$111	$155	$143
Income (loss) from investments (1)	49	7	43
Impairment of cost-based investments	—	(1)	—
Interest income and other	28	7	2
Total investing income	$188	$168	$188

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

In June 2010, we sold our 50 percent interest in Accroven SRL (Accroven) to the state-owned oil company, Petróleos de Venezuela S.A. (PDVSA) for $107 million. *Income (loss) from investments* in 2012, 2011, and 2010 includes gains of $53 million, $11 million, and $43 million, respectively, from the sale. As part of the settlement regarding certain Venezuelan assets in the first quarter of 2012 (see Note 3), we also received payment for all outstanding balances due from this sale, including interest. Payments were recognized upon receipt, as future collections were not reasonably assured.

Investments

	December 31, 2012	December 31, 2011
	(Millions)	
Equity method:		
Access Midstream Partners — 25%	$2,187	$ —
Overland Pass Pipeline Company LLC (OPPL) — 50%	454	433
Gulfstream — 50%	348	362
Laurel Mountain Midstream, LLC (Laurel Mountain) — 51% (1)	444	291
Discovery Producer Services LLC (Discovery) — 60% (1)	350	182
Other	204	122
	3,987	1,390
Cost method	—	1
Marketable equity securities	—	24
	$3,987	$1,415

(1) We account for these investments under the equity method due to the significant participatory rights of our partners such that we do not control or are otherwise not the primary beneficiary of the investments.

Marketable equity securities are classified as available-for-sale and included in *other current assets and deferred charges* in the Consolidated Balance Sheet. The carrying value is reported at fair value with net unrealized appreciation reported as a component of other comprehensive income.

Related party transactions

We have purchases from our equity method investees included in *product costs* in the Consolidated Statement of Operations of $186 million, $234 million, and $220 million for the years ended 2012, 2011, and 2010, respectively. We have $15 million and $23 million included in *accounts payable* in the Consolidated Balance Sheet with our equity method investees at December 31, 2012 and 2011, respectively.

WPZ has operating agreements with certain equity method investees. These operating agreements typically provide for reimbursement or payment to WPZ for certain direct operational payroll and employee benefit costs, materials, supplies, and other charges and also for management services. We supplied a portion of these services, primarily those related to employees since WPZ does not have any employees, to certain equity method investees. The total gross charges to equity method investees for these fees included in the Consolidated Statement of Operations are $75 million, $57 million and $38 million for the years ended 2012, 2011, and 2010, respectively.

Equity method investments

In addition to the discussion of the basis difference related to Access Midstream Partners in Note 2, we also have differences between the carrying value of our equity investments and the underlying equity in the net assets of the investees of $59 million at December 31, 2012, primarily related to impairments we previously recognized. These differences are amortized over the expected remaining life of the investees' underlying assets.

Our equity-method investees' organizational documents generally require distribution of available cash to equity holders on a quarterly basis. We generally fund our portion of significant expansion or development projects of these investees, except for Access Midstream Partners which is expected to be self-funding, through additional capital contributions. As of December 31, 2012, our proportionate share of amounts remaining to be spent for specific capital projects already in progress for Discovery and Laurel Mountain totaled $189 million and $55 million, respectively.

In December 2012, we completed the acquisition of a 25 percent ownership interest of Access Midstream Partners for approximately $2.19 billion in cash. (See Note 2.) We contributed $169 million to Discovery in 2012 and $174 million, $137 million and $43 million to Laurel Mountain in 2012, 2011 and 2010, respectively. In addition, in September 2010, we purchased an additional 49 percent ownership interest in OPPL for $424 million.

Dividends and distributions, including those presented below, received from companies accounted for by the equity method were $173 million, $193 million, and $175 million in 2012, 2011, and 2010, respectively. These transactions reduced the carrying value of our investments. These dividends and distributions primarily included:

	2012	2011	2010
		(Millions)	
Gulfstream	$79	$84	$ 81
Discovery	21	40	44
Aux Sable Liquid Products L.P.	28	35	28
OPPL	28	19	—

Summarized Financial Position and Results of Operations of All Equity Method Investments

	December 31,	
	2012	2011
	(Millions)	
Current assets	$ 582	$ 381
Noncurrent assets	11,571	8,004
Current liabilities	507	378
Noncurrent liabilities	3,807	2,324

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Gross revenue	$1,821	$1,808	$1,545
Operating income	557	747	732
Net income	488	654	624

Note 5. Asset Sales and Other Accruals

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

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Williams Partners			
Project feasibility costs	$ 21	$ 10	$ 8
Capitalization of project feasibility costs previously expensed	(19)	(11)	(1)
Gains on sales of certain assets	(6)	—	(12)
Involuntary conversion gains	—	(3)	(18)
Accrual of regulatory liability related to overcollection of certain employee expenses	4	9	10
Williams NGL & Petchem Services			
Gulf Liquids litigation contingency accrual reduction (see Note 17)	—	(19)	—

The reversals of project feasibility costs from expense to capital at Williams Partners are associated with natural gas pipeline expansion projects. These reversals were made upon determining that the related projects were probable of development. These costs are now included in the capital costs of the projects, which we believe are probable of recovery through the project rates.

Additional Items

We detected a leak in an underground cavern at our Eminence Storage Field in Mississippi on December 28, 2010. We recorded $2 million, $15 million, and $5 million of charges to *operating and maintenance expenses* at Williams Partners during 2012, 2011, and 2010, respectively, primarily related to assessment and monitoring costs incurred to ensure the safety of the surrounding area.

We engaged a consulting firm in 2012 to assist in better aligning resources to support our business strategy following the spin-off of WPX. In 2012, we recorded $26 million of reorganization-related costs, including consulting costs, to *selling, general, and administrative expenses.*

We completed a strategic restructuring transaction in the first quarter of 2010 that involved significant debt issuances, retirements, and amendments. During 2010, we incurred $45 million of related transaction costs reflected in *selling, general, and administrative expenses,* of which $7 million is attributable to noncontrolling interests.

In conjunction with the Gulf Liquids litigation contingency accrual reduction noted in the table above, Williams NGL & Petchem Services also reduced an accrual for the associated interest of $14 million in 2011, which is reflected in *interest incurred.* (See Note 17.)

In conjunction with the completion of a tender offer for a portion of our debt in the fourth quarter of 2011 and the 2010 strategic restructuring previously discussed, we incurred $271 million and $606 million, respectively, of *early debt retirement costs*, consisting primarily of cash premiums.

Note 6. Provision (Benefit) for Income Taxes

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

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Current:			
Federal	$ 91	$181	$ (21)
State	17	13	(2)
Foreign	40	(6)	29
	148	188	6
Deferred:			
Federal	220	(61)	144
State	(13)	(14)	(48)
Foreign	5	11	12
	212	(64)	108
Total provision (benefit)	$360	$124	$114

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

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Provision (benefit) at statutory rate	$451	$ 421	$135
Increases (decreases) in taxes resulting from:			
Impact of nontaxable noncontrolling interests	(72)	(96)	(58)
State income taxes (net of federal benefit)	2	11	(35)
Foreign operations — net	(36)	(14)	(22)
Federal settlements	—	(109)	—
International revised assessments	—	(38)	—
Taxes on undistributed earnings of certain foreign operations	—	(66)	66
Reduction of tax benefits on Medicare Part D federal subsidy	—	—	11
Other — net	15	15	17
Provision (benefit) for income taxes	$360	$ 124	$114

State income taxes (net of federal benefit) were reduced by $43 million in 2010 due to a reduction 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 $196 million, $173 million, and $144 million of foreign income in 2012, 2011, and 2010, 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,	
	2012	2011
	(Millions)	
Deferred tax liabilities:		
Property, plant, and equipment	$ 72	$ 65
Investments	3,146	2,560
Other	34	46
Total deferred tax liabilities	3,252	2,671
Deferred tax assets:		
Accrued liabilities	313	324
Minimum tax credits *	74	119
State loss and credit carryovers	195	170
Other	90	98
Total deferred tax assets	672	711
Less valuation allowance	144	145
Net deferred tax assets	528	566
Overall net deferred tax liabilities	$2,724	$2,105

* In conjunction with the 2011 spin-off of WPX, alternative minimum tax credits were allocated between us and WPX. In 2012, adjustments of $15 million were made to this component of the deferred tax asset for the 2009 to 2010 Internal Revenue Service (IRS) audit adjustments and finalization of the 2011 income tax return, reducing the alternative minimum tax credit allocated to WPX.

The valuation allowance at December 31, 2012 and 2011 serves to reduce the available deferred tax assets associated with state loss and credit carryovers to an amount that will, more likely than not, be realized. The amounts presented in the table above are, with respect to state items, before any federal benefit. The change from prior year for the *state loss and credit carryovers* is primarily due to increases in losses and credits generated in the current and prior years less losses and credits utilized in the current year. In the case of the *valuation allowance,* the change is due to the ongoing evaluation process of the losses and credits anticipated to be realized in future years.

In the fourth quarter of 2010, we provided $66 million of deferred taxes on the undistributed earnings of certain foreign operations that we no longer could assert were permanently reinvested due to alternatives being considered related to an existing structure impacted by the potential timing of our plan approved by our Board of Directors to pursue the separation of our exploration and production business through an IPO and subsequent tax-free spin-off. During the third quarter of 2011, associated with a ruling received from the IRS related to this separation plan, and following a certain internal reorganization, we recognized a deferred tax benefit of $66 million as we considered the undistributed earnings of these certain foreign operations to be permanently reinvested. As of December 31, 2012, we consider $630 million of undistributed earnings from 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 $198 million, $296 million, and $40 million in 2012, 2011, and 2010, respectively.

As of December 31, 2012, we had approximately $58 million of unrecognized tax benefits. If recognized, income tax expense would be reduced by $62 million, including the effect of these changes on other tax attributes, with state income tax amounts included net of federal tax effect. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2012	2011
	(Millions)	
Balance at beginning of period	$ 38	$ 91
Additions based on tax positions related to the current year	4	26
Additions for tax positions of prior years	22	4
Reductions for tax positions of prior years	(6)	(39)
Settlement with taxing authorities	—	(44)
Balance at end of period	$ 58	$ 38

We recognize related interest and penalties as a component of income tax provision. Total interest and penalties recognized as part of income tax provision were benefits of $7 million and $56 million for 2012 and 2011, respectively, and expense of $11 million for 2010. Approximately $7 million and $15 million of interest and penalties primarily relating to uncertain tax positions have been accrued as of December 31, 2012 and 2011, respectively.

During the next 12 months, we do not expect ultimate resolution of any unrecognized tax benefit associated with domestic or international matters to have a material impact on our unrecognized tax benefit position.

During the first quarter of 2011, we finalized settlements for 1997 through 2008 on certain contested matters with the IRS that resulted in a 2011 year-to-date tax benefit of approximately $109 million. In July and August 2011, we made cash payments to the IRS of $82 million and $77 million, respectively, related to these settlements. During the first and fourth quarters of 2011, we received revised assessments on an international matter that resulted in a 2011 tax benefit of approximately $38 million. In the first quarter of 2012, we received a cash refund for the revised assessments of $21 million.

During the third quarter of 2012, we reached a tentative agreement subject to government approval with the IRS on tax matters related to the IRS's examination of our 2009 and 2010 consolidated corporate income tax returns. These matters resulted in a tax provision of approximately $2 million recorded during the third quarter of 2012. With respect to the examined years, we anticipate making approximately $12 million of cash payments to the IRS in the first quarter of 2013. The 2011 tax return is subject to examination by the IRS. The statute of limitations for most states expires one year after expiration of the IRS statute. Generally, tax returns for our Venezuelan and Canadian entities are open to audit for tax years from 2007 through 2012, subject in the case of Venezuela to certain contractual limitations. An audit of one of our Canadian entities was concluded for the years 2007 through 2010 and we are awaiting a notice of reassessment based on a negotiated settlement. The impact of this reassessment is not expected to be material.

On December 23, 2011, the IRS issued temporary regulations providing guidance on the treatment of amounts paid to acquire, produce or improve tangible property and of dispositions of such property. In fourth quarter 2012, the IRS provided notice that the implementation date for these regulations has been delayed until January 1, 2014, and that additional, substantive changes to the initially issued temporary regulations would be forthcoming, likely in 2013. Changes for tax treatment elected by us or required by the regulations will generally be effective prospectively; however, implementation of many of the regulations' provisions will require a calculation of the cumulative effect of the changes on prior years, and it is expected that such amount will have to be included in the determination of our taxable income in 2014, or possibly over a four-year period beginning in 2014. The IRS is expected to issue additional procedural guidance regarding 2014 tax return filing requirements and how the requirements may be implemented for the gas transmission and distribution industry. Since changes will impact the timing for deducting expenditures for tax purposes, the impact of implementation will be reflected in the amount of income taxes payable or receivable, cash flows from operations and deferred taxes. Pending the issuance of additional procedural guidance from the IRS and progress of the evaluation process, we cannot estimate the impact of implementing the temporary regulations.

With the spin-off of WPX on December 31, 2011, WPX entered into a tax sharing agreement with us under which we are generally liable for all U.S. federal, state, local and foreign income taxes attributable to WPX with respect to taxable periods ending on or before the distribution date. We are also principally responsible for managing any income tax audits by the various tax jurisdictions for pre-spin-off periods. In 2012, we prepared pro forma tax returns for each tax period in which WPX or any of its subsidiaries were combined or consolidated with us for purposes of any 2011 tax return. We expect that we will reimburse WPX approximately $2 million in the first quarter of 2013 for the additional losses shown on the pro forma tax returns, offset with additional tax resulting from the tentative 2009 to 2010 IRS settlement agreement.

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

	Years Ended December 31,		
	2012	2011	2010
	(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)	$ 723	$ 803	$ 104
Basic weighted-average shares	619,792	588,553	584,552
Effect of dilutive securities:			
Nonvested restricted stock units	2,694	4,332	3,190
Stock options	2,608	3,374	2,957
Convertible debentures	392	1,916	—
Diluted weighted-average shares	625,486	598,175	590,699
Earnings (loss) per common share from continuing operations:			
Basic	$ 1.17	$ 1.36	$ .17
Diluted	$ 1.15	$ 1.34	$ .17

(1) 2011 includes $.7 million of interest expense, net of tax, associated with our convertible debentures. (See Note 13.) This amount has been added back to *income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders* to calculate diluted earnings per common share.

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 $222 million of income, then these shares would become dilutive.

Effective January 1, 2012, new awards of time-based restricted stock units contain a nonforfeitable right to dividends during the vesting period. These share-based payment awards are participating securities and are included in the computation of earnings (loss) per common share pursuant to the two-class method. The impact for the year ended December 31, 2012, is immaterial.

The table below includes information related to stock options for each period that were 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. All stock options outstanding at December 31, 2012 were dilutive.

	2012	2011	2010
Options excluded (millions)	—	0.9	2.4
Weighted-average exercise price of options excluded	$0.00	$29.68	$32.41
Exercise price ranges of options excluded	$0.00 - $0.00	$26.10 - $29.72	$22.68 - $40.51
Fourth quarter weighted-average market price	$33.38	$24.51	$22.47

Note 8. 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.

Funded Status

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years indicated. The spin-off on December 31, 2011, of WPX did not have a significant impact on our pension and other postretirement benefit plans. (See Note 3). Generally, our pension and other postretirement benefit plans have retained the benefit obligations associated with vested benefits earned by eligible employees that transferred to WPX due to the spin-off. No plan assets transferred to WPX.

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$1,441	$1,267	$ 339	$ 289
Service cost	39	41	3	2
Interest cost	55	64	13	15
Plan participants' contributions	—	—	5	6
Benefits paid	(75)	(66)	(20)	(22)
Medicare Part D and Early Retiree Reinsurance Program subsidies	—	—	3	4
Plan amendment	—	—	(6)	(3)
Actuarial loss (gain)	98	143	(6)	48
Settlements	(9)	(8)	—	—
Benefit obligation at end of year	1,549	1,441	331	339
Change in plan assets:				
Fair value of plan assets at beginning of year	965	971	159	162
Actual return on plan assets	111	—	18	(2)
Employer contributions	79	68	13	15
Plan participants' contributions	—	—	5	6
Benefits paid	(75)	(66)	(20)	(22)
Settlements	(9)	(8)	—	—
Fair value of plan assets at end of year	1,071	965	175	159
Funded status — underfunded	$ (478)	$ (476)	$(156)	$(180)
Accumulated benefit obligation	$1,519	$1,415		

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,	
	2012	2011
	(Millions)	
Underfunded pension plans:		
Current liabilities	$ 3	$ 7
Noncurrent liabilities	475	469
Underfunded other postretirement benefit plans:		
Current liabilities	8	8
Noncurrent liabilities	148	172

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 losses* of $98 million in 2012 and $143 million in 2011 are primarily due to the impact of decreases in the discount rates utilized to calculate the benefit obligation. The 2012 benefit obligation *actuarial gain* of $6 million for our other postretirement benefit plans is primarily due to changes to claims experience and health care cost trend rates, offset by the impact of a decrease in the discount rate utilized to calculate the benefit obligation. The 2011 benefit obligation *actuarial loss* of $48 million for our other postretirement benefit plans is primarily due to the impact of a decrease in the discount rate utilized to calculate the benefit obligation. In 2011, the *actuarial loss* includes a curtailment gain of $4 million for our pension plans and $1 million for our other postretirement benefit plans due to the spin-off of WPX.

At December 31, 2012 and 2011, 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 cost* 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 *net periodic benefit cost*. A portion of the *net actuarial loss* is amortized over the participants' average remaining future years of service, which is approximately 12 years for our pension plans and approximately 8 years for our other postretirement benefit plans.

Pre-tax amounts not yet recognized in *net periodic benefit cost* at December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
	(Millions)			
Amounts included in *accumulated other comprehensive loss*:				
Prior service (cost) credit	$ (1)	$ (2)	$ 7	$ 8
Net actuarial loss	(828)	(835)	(35)	(40)
Amounts included in *net regulatory assets* associated with our FERC-regulated gas pipelines:				
Prior service credit	N/A	N/A	$ 14	$ 14
Net actuarial loss	N/A	N/A	(67)	(85)

In addition to the *net regulatory assets* included in the previous table, differences in the amount of actuarially determined *net periodic benefit cost* 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 $38 million at December 31, 2012 and $34 million at December 31, 2011 related to these deferrals. These amounts will be reflected in future rates based on the gas pipelines' rate structures.

Net Periodic Benefit Cost

Net periodic benefit cost for the years ended December 31 consist of the following:

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
	(Millions)					
Components of net periodic benefit cost:						
Service cost	$ 39	$ 41	$ 35	$ 3	$ 2	$ 2
Interest cost	55	64	64	13	15	15
Expected return on plan assets	(64)	(77)	(71)	(9)	(10)	(9)
Amortization of prior service cost (credit)	1	1	1	(7)	(11)	(14)
Amortization of net actuarial loss	53	38	35	8	3	3
Net actuarial loss from settlements	5	4	—	—	—	—
Amortization of regulatory asset	—	—	—	—	1	1
Net periodic benefit cost	$ 89	$ 71	$ 64	$ 8	$—	$ (2)

Included in *net periodic benefit cost* in 2011 and 2010 in the previous table is cost associated with active and former employees that supported WPX's operations. This cost was directly charged to WPX and is included in *income (loss) from discontinued operations*. These amounts totaled $8 million in 2011 and $7 million in 2010 for our pension plans and totaled less than $1 million in 2011 and 2010 for our other postretirement benefit plans. The spin-off of WPX did not have a significant impact on *net periodic benefit cost* in 2012.

Items Recognized in Other Comprehensive Income (Loss)

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		
	2012	2011	2010	2012	2011	2010
	(Millions)					
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss)*:						
Net actuarial gain (loss)	$(51)	$(220)	$(71)	$ 2	$(21)	$(12)
Prior service credit	—	—	—	2	2	—
Amortization of prior service cost (credit)	1	1	1	(3)	(4)	(5)
Amortization of net actuarial loss and loss from settlements	58	42	35	3	1	1
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss)*	$ 8	$(177)	$(35)	$ 4	$(22)	$(16)

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, 2012, and include a *net actuarial gain* of $13 million, *prior service credit* of $4 million, *amortization of prior service credit* of $4 million, and *amortization of net actuarial loss* of $5 million. At December 31, 2011, amounts recognized in *net regulatory assets* included a *net actuarial loss* of $39 million, *prior service credit* of $1 million, *amortization of prior service credit* of $7 million, and *amortization of net actuarial loss* of $2 million. At December 31, 2010, amounts recognized in *net regulatory assets* included 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.

Pre-tax amounts expected to be amortized in *net periodic benefit cost* in 2013 are as follows:

	Pension Benefits	Other Postretirement Benefits
	(Millions)	
Amounts included in *accumulated other comprehensive loss*:		
Prior service cost (credit)	$ 1	$(3)
Net actuarial loss	60	3
Amounts included in *net regulatory assets* associated with our FERC-regulated gas pipelines:		
Prior service credit	N/A	$(5)
Net actuarial loss	N/A	6

Key Assumptions

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

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Discount rate	3.43%	3.98%	3.77%	4.22%
Rate of compensation increase	4.57	4.52	N/A	N/A

The weighted-average assumptions utilized to determine *net periodic benefit cost* for the years ended December 31 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Discount rate	3.98%	5.19%	5.78%	4.22%	5.35%	5.80%
Expected long-term rate of return on plan assets	6.30	7.50	7.50	5.71	6.54	6.51
Rate of compensation increase	4.52	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 decrease in discount rates from December 31, 2011 to December 31, 2012 is primarily due to the general market decline in yields on long-term, high-quality corporate debt securities.

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 long-term rates of return on plan assets assumptions decreased in 2012 as a result of an increase in the fixed income securities asset allocation, as well as a decrease in the forward-looking capital market projections.

The expected return on plan assets component of *net periodic benefit cost* 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 estimate of expected mortality rates for the participants in these plans. The selected mortality tables are among the most recent tables available and include projected mortality improvements.

The assumed health care cost trend rate for 2013 is 8.2 percent. This rate 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	46	(38)

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.

The pension plans' target asset allocation range at December 31, 2012 was 54 percent to 66 percent equity securities, which includes the commingled investment funds invested in equity securities, and 36 percent to 44 percent fixed income securities, including the fixed income commingled investment fund, 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.

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 generally 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 fixed income 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 2012, nine active investment managers and one passive investment manager managed substantially all of the pension plans' funds and four active investment managers and one passive investment manager 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 1 percent to 15 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, including a commingled fund invested in 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 fair values of our pension plan assets at December 31, 2012 and 2011, by asset class are as follows:

	2012			
	Level 1	Level 2	Level 3	Total
		(Millions)		
Pension assets:				
Cash management fund (1)	$ 21	$—	$—	$ 21
Equity securities:				
U.S. large cap	169	—	—	169
U.S. small cap	115	—	—	115
International developed markets large cap growth	1	61	—	62
Emerging markets growth	3	18	—	21
Preferred stock	6	—	—	6
Commingled investment funds:				
Equities — U.S. large cap (2)	—	146	—	146
Equities — Emerging markets value (3)	—	33	—	33
Equities — International developed markets large cap value (4)	—	83	—	83
Fixed income — Corporate bonds (5)	—	150	—	150
Fixed income securities (6):				
U.S. Treasury securities	22	—	—	22
Mortgage-backed securities	—	68	—	68
Corporate bonds	—	171	—	171
Insurance company investment contracts and other	—	4	—	4
Total assets at fair value at December 31, 2012	$337	$734	$—	$1,071

	2011			
	Level 1	Level 2	Level 3	Total
	(Millions)			
Pension assets:				
Cash management fund (1)	$ 43	$—	$—	$ 43
Equity securities:				
U.S. large cap	170	—	—	170
U.S. small cap	121	—	—	121
International developed markets large cap growth	4	57	—	61
Emerging markets growth	3	9	—	12
Commingled investment funds:				
Equities — U.S. large cap (2)	—	147	—	147
Equities — Emerging markets value (3)	—	27	—	27
Equities — International developed markets large cap value (4)	—	69	—	69
Fixed income — Corporate bonds (5)	—	58	—	58
Fixed income securities (6):				
U.S. Treasury securities	16	—	—	16
Mortgage-backed securities	—	65	—	65
Corporate bonds	—	169	—	169
Insurance company investment contracts and other	—	7	—	7
Total assets at fair value at December 31, 2011	$357	$608	$—	$965

The fair values of our other postretirement benefits plan assets at December 31, 2012 and 2011, by asset class are as follows:

	2012			
	Level 1	Level 2	Level 3	Total
	(Millions)			
Other postretirement benefit assets:				
Cash management funds (1)	$ 14	$—	$—	$ 14
Equity securities:				
U.S. large cap	42	—	—	42
U.S. small cap	21	—	—	21
International developed markets large cap growth	—	13	—	13
Emerging markets growth	1	4	—	5
Preferred stock	1	—	—	1
Commingled investment funds:				
Equities — U.S. large cap (2)	—	15	—	15
Equities — Emerging markets value (3)	—	3	—	3
Equities — International developed markets large cap value (4)	—	9	—	9
Fixed income — Corporate bonds (5)	—	15	—	15
Fixed income securities (7):				
U.S. Treasury securities	2	—	—	2
Government and municipal bonds	—	10	—	10
Mortgage-backed securities	—	7	—	7
Corporate bonds	—	18	—	18
Total assets at fair value at December 31, 2012	$ 81	$ 94	$—	$175

	2011			
	Level 1	Level 2	Level 3	Total
		(Millions)		
Other postretirement benefit assets:				
Cash management funds (1)	$ 16	$—	$—	$ 16
Equity securities:				
U.S. large cap	42	—	—	42
U.S. small cap	20	—	—	20
International developed markets large cap growth	1	12	—	13
Emerging markets growth	1	1	—	2
Commingled investment funds:				
Equities — U.S. large cap (2)	—	15	—	15
Equities — Emerging markets value (3)	—	3	—	3
Equities — International developed markets large cap value (4)	—	7	—	7
Fixed income — Corporate bonds (5)	—	6	—	6
Fixed income securities (7):				
U.S. Treasury securities	2	—	—	2
Government and municipal bonds	—	10	—	10
Mortgage-backed securities	—	6	—	6
Corporate bonds	—	17	—	17
Total assets at fair value at December 31, 2011	$ 82	$ 77	$—	$159

(1) The stated intent of these funds is to 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) The stated intent of this fund is to invest primarily in equity securities comprising the Standard & Poor's 500 Index. The investment objective of the fund is to approximate the performance of the Standard & Poor's 500 Index over the long term. The fund manager retains the right to restrict withdrawals from the fund so as not to disadvantage other investors in the fund.

(3) The stated intent of this fund is to invest in equity securities of international emerging markets for the purpose of capital appreciation. The fund invests primarily in common stocks in the financial, consumer goods, information technology, energy, telecommunications, materials, and industrial sectors. 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 so as not to disadvantage other investors in the fund.

(4) The stated intent of this fund is to invest 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, financial, health care, industrial, materials, energy, and information technology sectors. 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 so as not to disadvantage other investors in the fund.

(5) The stated intent of this fund is to invest in U.S. Corporate bonds and U.S. Treasury securities. The fund is managed to closely match the characteristics of a long-term corporate bond index fund and seeks to maintain an average credit quality target of A- or above and a maximum 10 percent allocation to BBB rated securities. The fund's target duration is approximately 20 years. The trustee of the fund reserves the right to delay the processing of deposits or withdrawals in order to ensure that securities transactions will be carried out in an orderly manner.

(6) The weighted-average credit quality rating of the pension assets fixed income security portfolio is investment grade with a weighted-average duration of 5.7 years for 2012 and 5.6 years for 2011.

(7) 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 4.9 years for 2012 and 4.8 years for 2011.

The 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 of an asset.

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 are estimated based on the net asset values per unit of each of the funds. The net asset values per unit represent the aggregate value of the funds assets at fair value less liabilities, divided by the number of units outstanding.

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.

There have been no significant changes in the preceding valuation methodologies used at December 31, 2012 and 2011. Additionally, there were no transfers or reclassifications of investments between Level 1 and Level 2 from December 2011 to December 2012. If transfers between levels had occurred, the transfers would have been recognized as of the end of the period.

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)	
2013	$ 77	$ 16	$ (2)
2014	86	17	(3)
2015	92	18	(3)
2016	97	18	(3)
2017	103	19	(3)
2018-2022	591	107	(18)

In 2013, we expect to contribute approximately $90 million to our tax-qualified pension plans and approximately $1 million to our nonqualified pension plans, for a total of approximately $91 million, and approximately $9 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 $25 million in 2012, $28 million in 2011, and $26 million in 2010. Included in these amounts are matching contributions for employees that supported WPX's operations that were directly charged to WPX and included in *income (loss) from discontinued operations* that totaled $5 million for both 2011 and 2010.

Note 9. Inventories

	December 31, 2012	December 31, 2011
	(Millions)	
Natural gas liquids, olefins, and natural gas in underground storage	$ 97	$ 98
Materials, supplies, and other	78	71
	$175	$169

Note 10. Property, Plant, and Equipment

	Estimated Useful Life (a) (Years)	Depreciation Rates (a) (%)	December 31, 2012	December 31, 2011
			(Millions)	
Nonregulated:				
Natural gas gathering and processing facilities	5 - 40		$ 7,727	$ 6,435
Construction in progress	(b)		1,997	648
Other	3 - 45		1,103	816
Regulated:				
Natural gas transmission facilities		1.01 - 6.82	9,963	9,593
Construction in progress		(b)	337	199
Other		.18 - 33.33	1,419	1,391
Total property, plant, and equipment, at cost			22,546	19,082
Accumulated depreciation and amortization			(7,079)	(6,502)
Property, plant, and equipment — net			$15,467	$12,580

(a) Estimated useful life and depreciation rates are presented as of December 31, 2012. Depreciation rates for regulated assets are prescribed by the FERC.

(b) Construction in progress balances not yet subject to depreciation.

Depreciation and amortization expense for *property, plant, and equipment — net* was $712 million in 2012, $658 million in 2011, and $611 million in 2010.

Regulated *property, plant, and equipment — net* includes $825 million and $865 million at December 31, 2012 and 2011, 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 underground storage caverns, offshore platforms, fractionation and compression 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 storage caverns and remove any related surface equipment, to restore land and remove surface equipment at gas processing, fractionation and compression 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 asset retirement obligations, of which $511 million and $507 million are included in *other noncurrent liabilities* with the remaining current portion in *accrued liabilities* at December 31, 2012 and 2011, respectively.

	December 31,	
	2012	2011
	(Millions)	
Beginning balance	$573	$499
Liabilities incurred	8	4
Liabilities settled	(44)	(46)
Accretion expense	43	39
Revisions (1)	(1)	77
Ending balance	$579	$573

(1) The 2012 revision primarily reflects a decrease in removal cost estimates, which is among several factors considered in the annual review process, including inflation rates, current estimates for removal cost, discount rates, and the estimated remaining life of the assets. The revision in 2011 is primarily due to increases in the inflation rate and estimated removal costs. The 2012 and 2011 revisions also include increases of $13 million and $39 million, respectively, related to changes in the timing and method of abandonment on certain of Transco's natural gas storage caverns that were associated with a leak in 2010.

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 was also required to make annual deposits into the trust through 2012. (See Note 15.)

Note 11. Accrued Liabilities

	December 31, 2012	December 31, 2011
	(Millions)	
Interest on debt	$148	$143
Employee costs	137	127
Asset retirement obligations	68	66
Other, including other loss contingencies	275	295
	$628	$631

Note 12. Debt, Banking Arrangements, and Leases

Long-Term Debt

	December 31, 2012	December 31, 2011
	(Millions)	
Unsecured:		
Transco:		
8.875% Notes due 2012	$ —	$ 325
6.4% Notes due 2016	200	200
6.05% Notes due 2018	250	250
7.08% Debentures due 2026	8	8
7.25% Debentures due 2026	200	200
5.4% Notes due 2041	375	375
4.45% Notes due 2042	400	—
Northwest Pipeline:		
7% Notes due 2016	175	175
5.95% Notes due 2017	185	185
6.05% Notes due 2018	250	250
7.125% Debentures due 2025	85	85
WPZ:		
3.8% Notes due 2015	750	750
7.25% Notes due 2017	600	600
5.25% Notes due 2020	1,500	1,500
4.125% Notes due 2020	600	600
4% Notes due 2021	500	500
3.35% Notes due 2022	750	—
6.3% Notes due 2040	1,250	1,250
Revolving credit loans	375	—
The Williams Companies, Inc.:		
7.875% Notes due 2021	371	371
3.7% Notes due 2023	850	—
7.5% Debentures due 2031	339	339
7.75% Notes due 2031	252	252
8.75% Notes due 2032	445	445
Various — 5.5% to 10.25% Notes and Debentures due 2019 to 2033	57	90
Other, including secured capital lease obligations	2	4
Net unamortized debt discount	(33)	(32)
Total long-term debt, including current portion	10,736	8,722
Long-term debt due within one year	(1)	(353)
Long-term debt	$10,735	$8,369

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

We have a $900 million senior unsecured revolving credit facility with a maturity date of June 3, 2016. The credit facility may, under certain conditions, be increased up to an additional $250 million. Significant financial covenants require our ratio of debt to EBITDA (each as defined in the credit facility) to be no greater than 4.5 to 1. For the fiscal quarter and the two following fiscal quarters in which one or more acquisitions for a total aggregate purchase price equal to or greater than $50 million has been executed, we are required to maintain a ratio of debt to EBITDA of no greater than 5 to 1. At December 31, 2012, we are in compliance with these financial covenants.

In September 2012, WPZ amended its existing $2 billion senior unsecured revolving credit facility to increase the aggregate commitments by $400 million. The maturity date of the amended credit facility is June 3, 2016. This credit facility was also amended to provide that WPZ may request an additional $400 million increase in commitments to be available under certain conditions in the future. This credit facility includes Transco and Northwest Pipeline as co-borrowers and is only available to named borrowers. 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 the other co-borrowers. Significant financial covenants include:

- WPZ's ratio of debt to EBITDA (each as defined in the credit facility) must be no greater than 5 to 1. For the fiscal quarter and the two following fiscal quarters in which one or more acquisitions for a total aggregate purchase price equal to or greater than $50 million has been executed, WPZ is required to maintain a ratio of debt to EBITDA of no greater than 5.5 to 1;
- The ratio of debt to capitalization (defined as net worth plus debt) must be no greater than 65 percent for each of Transco and Northwest Pipeline.

At December 31, 2012, WPZ is in compliance with these financial covenants.

The two credit agreements contain the following terms and conditions:

- Each time funds are borrowed, the applicable borrower may choose from two methods of calculating interest: a fluctuating base rate equal to Citibank N.A.'s alternate base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. The applicable borrower is required to pay a commitment fee (currently 0.25 percent for our agreement and 0.20 percent for the WPZ agreement) based on the unused portion of their respective credit facility. The applicable margin and the commitment fee are determined for each borrower by reference to a pricing schedule based on such borrower's senior unsecured long-term debt ratings.
- Various covenants may limit, among other things, a borrower's and its material subsidiaries' ability to grant certain liens supporting indebtedness, a borrower's ability to merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default, make investments, and allow any material change in the nature of its business.
- If an event of default with respect to a borrower occurs under their respective credit facility agreement, the lenders will be able to terminate the commitments for the respective borrowers and accelerate the maturity of any loans of the defaulting borrower under the respective credit facility agreement and exercise other rights and remedies.

Letter of credit capacity under our $900 million and WPZ's $2.4 billion credit facilities is $700 million and $1.3 billion, respectively. At December 31, 2012, no letters of credit have been issued on either facility. No loans are outstanding on our credit facility at December 31, 2012. Loans totaling $375 million are outstanding on WPZ's credit facility at December 31, 2012. We have issued letters of credit totaling $27 million as of December 31, 2012, under certain bilateral bank agreements.

Issuances and Retirements

In December 2012, we completed a public offering of $850 million of 3.7 percent senior unsecured notes due 2023. We used the net proceeds to finance a portion of our investment in Access Midstream Partners. (See Note 2.)

In August 2012, WPZ completed a public offering of $750 million of 3.35 percent senior unsecured notes due 2022. WPZ used the net proceeds to repay outstanding borrowings on its senior unsecured revolving credit facility and for general partnership purposes.

In July 2012, Transco issued $400 million of 4.45 percent senior unsecured notes due 2042 to investors in a private debt placement. A portion of these proceeds was used to repay Transco's $325 million 8.875 percent senior unsecured notes that matured on July 15, 2012. 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 November 2012 and completed in December 2012.

In August 2011, Transco issued $375 million of 5.4 percent senior unsecured notes due 2041 to investors in a private debt placement. 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 February 2012 and completed in March 2012.

Other Debt Disclosures

As of December 31, 2012, aggregate minimum maturities of long-term debt (excluding capital leases and unamortized discount) for each of the next five years are as follows:

	(Millions)
2013	$—
2014	$—
2015	$750
2016	$750
2017	$785

Cash payments for interest were $539 million in 2012, $599 million in 2011 and $614 million in 2010.

We have considered the guidance in the Securities and Exchange Commission's Regulation S-X related to restricted net assets of subsidiaries. In accordance with Rule 4-08(e) of Regulation S-X, we have determined that certain net assets of our subsidiaries are considered restricted under this guidance and exceed 25 percent of our consolidated net assets. Substantially all of these restricted net assets relate to the net assets of WPZ, which are technically considered restricted under this accounting rule due to terms within WPZ's partnership agreement that govern the partnership's assets. Our interest in WPZ's net assets at December 31, 2012 was $6.2 billion.

Leases-Lessee

Future minimum annual rentals under noncancelable operating leases as of December 31, 2012 are payable as follows:

	(Millions)
2013	$ 50
2014	44
2015	42
2016	35
2017	27
Thereafter	138
Total	$336

Under our right-of-way agreement with the Jicarilla Apache Nation, we make annual payments of approximately $8 million and an additional annual payment which varies depending on the prior year's per-unit NGL margins and the volume of gas gathered by our Williams Partners gathering facilities subject to the agreement. Depending primarily on the per-unit NGL margins for any given year, the additional annual payments could exceed the fixed amount. This agreement expires March 31, 2029.

Total rent expense was $56 million in 2012, $49 million in 2011, and $45 million in 2010.

Note 13. Stockholders' Equity

Cash dividends declared per common share were $1.19625, $.775 and $.485 for 2012, 2011, and 2010, respectively.

In April 2012, we issued approximately 30 million shares of common stock in a public offering at a price of $30.59 per share. We used the net proceeds of $887 million to fund a portion of the purchase of additional WPZ common units in connection with WPZ's Caiman Acquisition. (See Note 2.)

In December 2012, we issued approximately 53 million shares of common stock in a public offering at a price of $31 per share. We used the net proceeds of $1.6 billion to fund a portion of the purchase of an equity interest in ACMP. (See Note 2.)

At December 31, 2012, approximately $2 million of our original $300 million, 5.5 percent junior subordinated convertible debentures, convertible into less than one million shares of common stock, remain outstanding. In 2012, 2011 and 2010, we converted $6 million, $14 million and $2 million, respectively, of the debentures in exchange for approximately one million, one million and less than one million shares, respectively, of common stock.

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.

AOCI

The following table presents the balances of the components of our AOCI, net of income taxes, as of December 31:

	2012	2011
	(Millions)	
Cash flow hedges	$ (1)	$ —
Foreign currency translation	169	147
Pension and other postretirement benefits (see Note 8)	(530)	(539)
Equity securities	—	3
Total accumulated other comprehensive loss, net of income taxes	$(362)	$(389)

Note 14. 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, 2012, 27 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 16 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. 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 194 thousand shares at an average price of $23.75 per share during 2012. Approximately 616 thousand shares were available for purchase under the ESPP at December 31, 2012.

Total stock-based compensation expense for the years ended December 31, 2012, 2011, and 2010 was $36 million, $52 million, and $48 million, respectively, of which $18 million and $14 million are included in *income (loss) from discontinued operations* for 2011 and 2010, respectively. Measured but unrecognized stock-based compensation expense at December 31, 2012, was $40 million, which does not include the effect of estimated forfeitures of $1 million. This amount is comprised of $3 million related to stock options and $37 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, 2012.

Stock Options	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
	(Millions)		(Millions)
Outstanding at December 31, 2011	9.6	$15.63	
Granted	1.1	$29.11	
Exercised	(3.8)	$13.21	
Outstanding at December 31, 2012	6.9	$19.10	$94
Exercisable at December 31, 2012	5.1	$16.68	$82

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $69 million, $55 million, and $20 million, respectively; and the tax benefit realized was $25 million, $21 million, and $7 million, respectively. Cash received from stock option exercises was $50 million, $45 million, and $7 million during 2012, 2011, and 2010, respectively. The weighted-average remaining contractual life for stock options outstanding and exercisable at December 31, 2012, was 5.2 years and 4.0 years, respectively.

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:

	2012	2011	2010
Weighted-average grant date fair value of options for our common stock granted during the year, per share	$5.65	$6.28	$5.71
Weighted-average assumptions:			
Dividend yield	3.7%	3.6%	2.6%
Volatility	30.0%	34.6%	39.0%
Risk-free interest rate	1.3%	2.8%	3.0%
Expected life (years)	6.5	6.5	6.5

The expected dividend yield is based on the 2012 dividend forecast and the grant-date market price of our stock. As a result of the 2011 spin-off of WPX, the historical volatility of our stock is not expected to be as representative of expected future volatility. Expected volatility is now based on the average of our peer group 10-year historical volatility adjusted by a ratio of our implied volatility to the average of our peer group's implied volatility. The adjustment is made because the difference in implied volatility between our peer group and us may indicate that we are expected to be more volatile than our peer group average. 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, 2012.

Restricted Stock Units Outstanding	Shares	Weighted-Average Fair Value*
	(Millions)	
Nonvested at December 31, 2011	5.2	$14.12
Granted	2.0	$20.61
Forfeited	(0.4)	$11.55
Vested	(2.9)	$ 7.84
Nonvested at December 31, 2012	3.9	$22.49

* Performance-based shares are valued utilizing a Monte Carlo valuation method using measures of total shareholder return. All other shares are valued at the grant-date market price or the grant-date market price less dividends projected to be paid over the vesting period.

Value of Restricted Stock Units	2012	2011	2010
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$20.61	$23.31	$16.37
Total fair value of restricted stock units vested during the year ($'s in millions)	$ 22	$ 35	$ 29

Performance-based shares granted under the Plan represent 30 percent of nonvested restricted stock units outstanding at December 31, 2012. These grants may be earned at the end of a three-year period based on actual performance against a performance target. 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 15. Fair Value Measurements

The following table presents, by level within the fair value hierarchy, certain of our financial assets and liabilities. The carrying values of cash and cash equivalents, accounts receivable and accounts payable approximate fair value because of the short-term nature of these instruments. Therefore, these assets and liabilities are not presented in the following table.

			Fair Value Measurements Using		
	Carrying Amount	Fair Value	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(Millions)		
Assets (liabilities) at December 31, 2012:					
Measured on a recurring basis:					
ARO Trust investments	$ 18	$ 18	$ 18	$ —	$ —
Energy derivatives assets not designated as hedging instruments	5	5	—	—	5
Energy derivatives liabilities not designated as hedging instruments	(1)	(1)	—	—	(1)
Additional disclosures:					
Notes receivable and other	95	138	2	8	128
Long-term debt, including current portion (a)	(10,734)	(12,388)	—	(12,388)	—
Guarantee	(33)	(31)	—	(31)	—
Assets (liabilities) at December 31, 2011:					
Measured on a recurring basis:					
ARO Trust investments	$ 25	$ 25	$ 25	$ —	$ —
Available-for-sale equity securities	24	24	24	—	—
Energy derivatives assets not designated as hedging instruments	1	1	1	—	—
Additional disclosures:					
Notes receivable and other	57	57	N/A	N/A	N/A
Long-term debt, including current portion (a)	(8,718)	(10,043)	N/A	N/A	N/A
Guarantee	(34)	(32)	N/A	N/A	N/A

(a) Excludes capital leases

Fair Value Methods

We use the following methods and assumptions in estimating the fair value of our financial instruments:

Assets and liabilities measured at fair value on a recurring basis

ARO Trust investments: Transco deposits a portion of its collected rates, pursuant to its 2008 rate case settlement, into an external trust (ARO Trust) that is specifically designated to fund future asset retirement obligations. The ARO Trust invests in a portfolio of actively traded mutual funds that are measured at fair value on a recurring basis based on quoted net asset values, is classified as available-for-sale, and is reported in *regulatory assets, deferred charges, and other* in the Consolidated Balance Sheet. Both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

Energy derivatives: Energy derivatives include commodity based exchange-traded contracts and over-the-counter (OTC) contracts, which consist of physical forwards, futures, and swaps that are measured at fair value on a recurring basis. 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 do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions. Energy derivatives assets are reported in *other current assets and deferred charges* and *regulatory assets, deferred charges, and other* in the Consolidated Balance Sheet. Energy derivatives liabilities are reported in *other noncurrent liabilities* in the Consolidated Balance Sheet.

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 transfers between Level 1 and Level 2 occurred during the years ended December 31, 2012 or 2011.

Additional fair value disclosures

Notes receivable and other: Notes receivable and other includes a receivable related to the sale of certain former Venezuela assets. To determine the disclosed fair value of this receivable at December 31, 2012, we considered an income approach. We calculated the net present value of a probability-weighted set of cash flows utilizing assumptions based on contractual terms, historical payment patterns by the counterparty, future probabilities of default, our likelihood of using arbitration if the counterparty does not perform, and discount rates. We determined the fair value of the receivable to be $93 million at December 31, 2012. The carrying value of this receivable is $49 million at December 31, 2012. The current and noncurrent portions are reported in *accounts and notes receivable* and *regulatory assets, deferred charges, and other*, respectively, in the Consolidated Balance Sheet.

Notes receivable and other also includes a receivable from our former affiliate, WPX (see Note 17) and other notes receivable. The disclosed fair value of these receivables is determined by an income approach which considers the underlying contract amounts and our assessment of our ability to recover these amounts. The current portion is reported in *accounts and notes receivable*, and the noncurrent portion is reported in *regulatory assets, deferred charges, and other* in the Consolidated Balance Sheet.

Long-term debt: The disclosed fair value of our long-term debt is determined by a market approach using broker quoted indicative period-end bond prices. The quoted prices are based on observable transactions in less active markets for our debt or similar instruments.

Guarantee: The guarantee represented in the table consists of a guarantee we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on a lease performance obligation that extends through 2042.

To estimate the disclosed fair value of the guarantee, an estimated default rate is applied to the sum of the future contractual lease payments using an income approach. The estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate based on the credit rating of WilTel's current owner and the term of the underlying obligation. The default rate is published by Moody's Investors Service. This guarantee is reported in *accrued liabilities* in the Consolidated Balance Sheet.

Guarantees

We are required by our revolving credit agreements to indemnify lenders for certain taxes required to be withheld from payments due to the lenders and for certain 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.

Regarding our previously described guarantee of Wiltel's lease performance, the maximum potential exposure is approximately $36 million at December 31, 2012 and $38 million at December 31, 2011. Our exposure declines systematically throughout the remaining term of WilTel's obligation.

We have provided guarantees in the event of nonpayment by our previously owned subsidiary, WPX, on certain contracts, primarily including a long-term transportation capacity agreement and a natural gas purchase contract, extending through 2017 and 2023, respectively. We estimate the maximum undiscounted potential future payment obligation under these remaining guarantees is approximately $232 million at December 31, 2012. Our recorded liability for these guarantees, which considers our estimate of the fair value of the guarantees, is insignificant.

Note 16. Derivative Instruments and Concentration of Credit Risk

Energy Commodity Derivatives

Risk management activities

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases and/or sales of natural gas, NGLs and olefins attributable to commodity price risk. The energy commodity derivatives in our current portfolio 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 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. In addition, we buy NGLs as feedstock to generate olefins. To reduce exposure to a decrease in revenues from fluctuations in NGL and olefin market prices or increases in costs and operating expenses from fluctuations in natural gas and NGL market prices, we may enter into NGL, olefin or natural gas swap agreements, futures contracts, financial or physical forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs and olefins and purchases of natural gas and NGLs. Those designated as 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.

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 two types:

- Central hub risk: Financial derivative exposures to Mont Belvieu for NGLs;
- Basis risk: Financial and physical derivative exposures to the difference in value between the central hub and another specific delivery point.

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of December 31, 2012. NGLs are presented in barrels.

Derivative Notional Volumes	Unit of Measure	Central Hub Risk	Basis Risk
Not Designated as Hedging Instruments			
Williams Partners	Barrels	(185,000)	(38,256,000)

Gains (losses)

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in AOCI, *product sales,* or *product costs.*

	Years ended December 31,		
	2012	2011	Classification
	(Millions)		
Net gain (loss) recognized in other comprehensive income (loss) (effective portion)	$30	$(18)	AOCI
Net gain (loss) reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$30	$(18)	Product Sales or Product Costs

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 at December 31, 2012 and 2011:

	December 31,	
	2012	2011
	(Millions)	
Receivables by product or service:		
Sale of NGLs and related products and services	$411	$446
Transportation of natural gas and related products	170	164
Other	107	27
Total	$688	$637

Customers include producers, distribution companies, industrial users, gas marketers and pipelines primarily located in the central, 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.

Revenues

In 2012, 2011, and 2010, we had one customer in our Williams Partners segment that accounted for 14 percent, 17 percent and 15 percent of our consolidated revenues, respectively.

Note 17. Contingent Liabilities and Commitments

Indemnification of WPX Matters

We have agreed to indemnify our former affiliate, WPX and its subsidiaries, related to the following matters. In connection with this indemnification, we have retained applicable accrued asset and liability balances associated with these matters, and as a result, have an indirect exposure to future developments in these matters.

Issues resulting from California energy crisis

WPX's former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by WPX 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. WPX has 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, WPX continues to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. WPX and certain California utilities have agreed in principle to resolve WPX's collection of accrued interest from counterparties as well as WPX's payment of accrued interest on refund amounts. As currently contemplated by the parties, the settlement, which is subject to FERC and California regulatory approval, would resolve most of WPX's legal issues arising from the 2000-2001 California Energy Crisis. We currently have a net receivable from WPX related to these matters.

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 WPX and others, in each case seeking an unspecified amount of damages. WPX is 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 natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of WPX and most of the other defendants based on plaintiffs' lack of standing. In 2009, the court denied the plaintiffs' request for reconsideration of the Colorado dismissal and entered judgment in WPX's favor. The court's order became final on July 18, 2011, and the Colorado plaintiffs might appeal the order.

In the other cases, on July 18, 2011, the Nevada district court granted WPX's joint motions for summary judgment to preclude the plaintiffs' state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs' class certification motion as moot. In 2011, the plaintiffs' appealed the court's ruling to the Ninth Circuit Court of Appeals, and in early 2012, the parties completed briefing the issues. A decision is expected in 2013. Because of the uncertainty around these current pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time. However, it is reasonably possible that the ultimate resolution of these items and our related indemnification obligation could result in future charges that may be material to our results of operations.

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 accrued 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. As a result, we reduced our accrued liability as of December 31, 2011 by $33 million, including $14 million of interest. The Texas Court of Appeals also reversed and remanded the remaining claims for further proceedings. None of the parties filed a petition for review in the Texas Supreme Court. On May 8, 2012, the Texas Court of Appeals issued its mandate remanding the original breach of contract claims involving Gulsby and attorney fee claims (the remaining claims) to trial court.

Alaska refinery contamination litigation

In January 2010, James West filed a class action lawsuit in state court in Fairbanks, Alaska on behalf of individual property owners whose water contained sulfolane contamination allegedly emanating from the Flint Hills Oil Refinery in North Pole, Alaska. The suit named our subsidiary, Williams Alaska Petroleum Inc. (WAPI), and Flint Hills Resources Alaska, LLC (FHRA), a subsidiary of Koch Industries, Inc., as defendants. We owned and operated the refinery until 2004 when we sold it to FHRA. We and FHRA have made claims under the pollution liability insurance policy issued in connection with the sale of the North Pole refinery to FHRA. We and FHRA also filed claims against each other seeking, among other things, contractual indemnification alleging that the other party caused the sulfolane contamination.

In August 2010, the court denied West's request for class certification. On May 5, 2011, we and FHRA settled the James West claim, leaving FHRA and Williams' claims. We filed motions for summary judgment on FHRA's claims against us, but the motions are unlikely to resolve all the outstanding claims. Similarly, FHRA has filed motions for summary judgment that would resolve some, but not all, of our claims against it. An April 2013 trial date had been scheduled, but has been stricken and has not been reset.

We currently estimate that our reasonably possible loss exposure in this matter could range from an insignificant amount up to $32 million, although uncertainties inherent in the litigation process, expert evaluations, and jury dynamics might cause our exposure to exceed that amount. We might have the ability to recover any such losses under the pollution liability policy if FHRA has not exhausted the policy limits.

Independent of the litigation matter described in the preceding paragraphs, during the fourth quarter 2012, the Alaska Department of Environmental Conservation (ADEC) requested that we and the FHRA voluntarily enter into a compliance order by consent with it for environmental remediation of sulfolane and other possible contaminants. Discussions on these issues are ongoing. ADEC has indicated that it views us and FHRA as responsible parties. As such, we will likely be required to contribute some amount, whether to reimburse the State, to reimburse FHRA, or to comply with an ADEC order. Due to the ongoing assessment of the level and extent of sulfolane contamination and the ultimate cost of remediation and division of costs between the named responsible parties, we are unable to estimate a range of liability at this time.

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 2011, Liberty asserted 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 counterclaim and determine the amount of any possible liability.

Environmental Matters

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations and remedial processes at certain sites, some of which we currently do not own. We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), and other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. 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. As of December 31, 2012, we have accrued liabilities totaling $46 million for these matters, as discussed below. Our accrual reflects the most likely costs of cleanup, which are generally based on completed assessment studies, preliminary results of studies or our experience with other similar cleanup operations. Certain assessment studies are still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Any incremental amount in excess of amounts currently accrued cannot be reasonably estimated at this time due to uncertainty about the actual number of contaminated sites ultimately identified, the actual amount and extent of contamination discovered and the final cleanup standards mandated by the EPA and other governmental authorities.

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. More recent 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.

Continuing operations

Our interstate gas pipelines are involved in remediation activities related to certain facilities and locations for polychlorinated biphenyls, mercury, and other hazardous substances. These activities have involved the EPA and various state environmental authorities, resulting in our identification as a potentially responsible party at various Superfund waste sites. At December 31, 2012, we have accrued liabilities of $10 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, 2012, we have accrued liabilities totaling $7 million for these costs.

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 relate to the operations of the assets and businesses described below.

- Former agricultural fertilizer and chemical operations and former retail petroleum and refining operations;
- Former petroleum products and natural gas pipelines;
- Former petroleum refining facilities;
- Former exploration and production and mining operations;
- Former electricity and natural gas marketing and trading operations.

At December 31, 2012, we have accrued environmental liabilities of $29 million related to these matters.

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, 2012, other than as previously disclosed, we are not aware of any material claims involving the indemnities; thus, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. Any claim for indemnity brought against us in the future 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

We have disclosed our estimated range of reasonably possible losses for certain matters above, as well as all significant matters for which we are unable to reasonably estimate a range of possible loss. We estimate that for all other matters for which we are able to reasonably estimate a range of loss, our aggregate reasonably possible losses beyond amounts accrued are immaterial to our expected future annual results of operations, liquidity and financial position. These calculations have been made without consideration of any potential recovery from third parties.

Commitments

Commitments for construction and acquisition of property, plant, and equipment are approximately $1.3 billion at December 31, 2012.

Note 18. Segment Disclosures

Our reporting segments are Williams Partners, Williams NGL & Petchem Services, and Access Midstream Partners. All remaining business activities are included in Other. Following completion of WPZ's purchase of the olefins production facility in Geismar, Louisiana, during the fourth quarter of 2012, the former Midstream Canada & Olefins segment is renamed Williams NGL & Petchem Services. All prior periods have been recast to reflect this transaction. (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 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.

On December 20, 2012, we acquired an approximate 24 percent ownership interest in ACMP and a 50 percent indirect interest in Access GP for approximately $2.19 billion. Our segment presentation of Access Midstream Partners reflects the significant size of this investment and the economic opportunities it represents in major unconventional producing areas that will add diversity to our current asset base.

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. General corporate expenses* represent *selling, general, and administrative expenses* that are not allocated to our segments. 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 following geographic area data includes *revenues from external customers* based on product shipment origin and *long-lived assets* based upon physical location.

	United States	Other	Total
		(Millions)	
Revenues from external customers:			
2012	$ 7,335	$151	$ 7,486
2011	7,728	202	7,930
2010	6,471	167	6,638
Long-lived assets:			
2012	$16,940	$880	$17,820
2011	12,041	583	12,624
2010	11,384	408	11,792

Our foreign operations are located in Canada. *Long-lived assets* are comprised of property, plant, and equipment, goodwill, and other intangible assets.

As discussed in Notes 1 and 3, our former exploration and production business was spun-off on December 31, 2011 and has been reported as discontinued operations in all prior periods presented. Revenues derived from intercompany sales to our former exploration and production business, previously reported as internal, are now shown as external. These sales were $310 million and $264 million for the years ended 2011 and 2010, respectively. In addition, costs attributable to activities with our former exploration and production business, previously reported as internal, are now shown as external. Such costs were $845 million and $797 million for the years ended 2011 and 2010, respectively.

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	Williams NGL & Petchem Services	Access Midstream Partners	Other	Eliminations	Total
			(Millions)			
2012						
Segment revenues:						
Service revenues						
External	$2,709	$ 5	$—	$ 15	$ —	$2,729
Internal	—	—	—	12	(12)	—
Total service revenues	2,709	5	—	27	(12)	2,729
Product sales						
External	4,611	146	—	—	—	4,757
Internal	—	128	—	—	(128)	—
Total product sales	4,611	274	—	—	(128)	4,757
Total revenues	$7,320	$279	$—	$ 27	$(140)	$7,486
Segment profit (loss)	$1,812	$ 99	$—	$ 49	$ —	$1,960
Less:						
Equity earnings (losses)	111	—	—	—	—	111
Income (loss) from investments	—	(4)	—	53	—	49
Segment operating income (loss)	$1,701	$103	$—	$ (4)	$ —	1,800
General corporate expenses						(188)
Operating income (loss)						$1,612
Other financial information:						
Additions to long-lived assets	$5,562	$425	$—	$ 31	$ —	$6,018
Depreciation and amortization	$ 714	$ 20	$—	$ 22	$ —	$ 756
2011						
Segment revenues:						
Service revenues						
External	$2,517	$ 1	$—	$ 14	$ —	$2,532
Internal	—	—	—	11	(11)	—
Total service revenues	2,517	1	—	25	(11)	2,532
Product sales						
External	5,197	201	—	—	—	5,398
Internal	—	139	—	—	(139)	—
Total product sales	5,197	340	—	—	(139)	5,398
Total revenues	$7,714	$341	$—	$ 25	$(150)	$7,930
Segment profit (loss)	$2,035	$157	$—	$ 24	$ —	$2,216
Less:						
Equity earnings (losses)	142	—	—	13	—	155
Income (loss) from investments	—	(4)	—	11	—	7
Segment operating income (loss)	$1,893	$161	$—	$—	$ —	2,054
General corporate expenses						(187)
Operating income (loss)						$1,867
Other financial information:						
Additions to long-lived assets	$1,273	$211	$—	$ 46	$ —	$1,530
Depreciation and amortization	$ 621	$ 16	$—	$ 24	$ —	$ 661

	Williams Partners	Williams NGL & Petchem Services	Access Midstream Partners	Other	Eliminations	Total
			(Millions)			
2010						
Segment revenues:						
Service revenues						
External	$2,346	$ 1	$—	$ 12	$—	$2,359
Internal	—	—	—	12	(12)	—
Total service revenues	2,346	1	—	24	(12)	2,359
Product sales						
External	4,113	166	—	—	—	4,279
Internal	—	71	—	—	(71)	—
Total product sales	4,113	237	—	—	(71)	4,279
Total revenues	$6,459	$238	$—	$ 24	$(83)	$6,638
Segment profit (loss)	$1,666	$ 80	$—	$ 68	$—	$1,814
Less:						
Equity earnings (losses)	109	—	—	34	—	143
Income (loss) from investments	—	—	—	43	—	43
Segment operating income (loss)	$1,557	$ 80	$—	$ (9)	$—	1,628
General corporate expenses						(221)
Operating income (loss)						$1,407
Other financial information:						
Additions to long-lived assets	$ 911	$ 97	$—	$ 25	$—	$1,033
Depreciation and amortization	$ 578	$ 13	$—	$ 21	$—	$ 612

The following table reflects *total assets* and *equity method investments* by reportable segments, including discontinued operations.

	Total Assets		Equity Method Investments		
	December 31, 2012	December 31, 2011	December 31, 2012	December 31, 2011	December 31, 2010
			(Millions)		
Williams Partners (a)	$19,709	$14,672	$1,800	$1,383	$1,045
Williams NGL & Petchem Services	1,134	837	—	—	—
Access Midstream Partners (a)	2,187	—	2,187	—	—
Other	1,782	1,275	—	7	193
Eliminations	(485)	(282)	—	—	—
Discontinued operations (see Note 3)	—	—	—	—	104
Total	$24,327	$16,502	$3,987	$1,390	$1,342

(a) The increase in total assets of Williams Partners is primarily due to the Laser and Caiman Acquisitions. See Note 2. See Note 2 and Note 4 for a discussion on Access Midstream Partners.

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)			
2012				
Revenues	$2,019	$1,846	$1,752	$1,869
Product costs	957	900	771	868
Income (loss) from continuing operations	359	166	200	204
Net income (loss)	495	165	203	202
Amounts attributable to The Williams Companies, Inc.:				
Income (loss) from continuing operations	287	133	152	151
Net income (loss)	423	132	155	149
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	0.48	0.21	0.25	0.23
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	0.47	0.21	0.25	0.23
2011				
Revenues	$1,871	$1,984	$1,972	$2,103
Product costs	926	990	969	1,049
Income (loss) from continuing operations	360	239	321	158
Net income (loss)	384	297	342	(362)
Amounts attributable to The Williams Companies, Inc.:				
Income (loss) from continuing operations	300	171	253	79
Net income (loss)	321	227	272	(444)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	0.51	0.29	0.43	0.14
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	0.50	0.29	0.43	0.13

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to changes in the average number of common shares outstanding and rounding.

We have changed the basis for presenting our Consolidated Statement of Operations. This included separating *costs and operating expenses* into *product costs*, *operating and maintenance expenses*, and *depreciation and amortization expenses*. (See Note 1 of Notes to Consolidated Financial Statements.)

2012

Net income for fourth-quarter 2012 includes the following pre-tax items:

- $18 million related to the reversal of project feasibility costs from expense to capital at Williams Partners (see Note 5);
- $12 million of reorganization-related costs including engaging a consulting firm in 2012 to assist in better aligning resources to support our business strategy following the spin-off of WPX (see Note 5).

Net income for second-quarter 2012 includes $21 million of Caiman and Laser acquisition and transition-related costs at Williams Partners (see Note 2).

Net income for first-quarter 2012 includes the following pre-tax items:

- $63 million of income, including $10 million of interest, related to the sale of our 50 percent interest in Accroven at Other (see Note 4);
- $144 million of gain on reconsolidation related to our majority ownership in the Wilpro entities (see summarized results of discontinued operations at Note 3).

2011

Net loss for fourth-quarter 2011 includes the following pre-tax items:

- $271 million of early debt retirement costs consisting primarily of cash premiums of $254 million (see Note 5);
- $560 million of impairment charges primarily related to impairments of certain properties of our discontinued exploration and production business in the Powder River basin and Barnett Shale (see summarized results of discontinued operations at Note 3);
- $179 million of impairment charges associated with our investment in WPX (see summarized results of discontinued operations at Note 3);
- $33 million of income including associated interest related to the reduction of the Gulf Liquids litigation contingency accrual at Williams NGL & Petchem Services (see Notes 5 and 17);
- $30 million of transaction costs related to the spin-off of our exploration and production former business (see summarized results of discontinued operations at Note 3).

Net loss for fourth-quarter 2011 also includes a $26 million net tax benefit associated with the write-down of certain indebtedness related to our former power operations (see summarized results of discontinued operations at Note 3).

Net income for third-quarter 2011 includes a $66 million tax benefit to reverse taxes on undistributed earnings of certain foreign operations that are now considered to be permanently reinvested (see Note 6).

Net income for first-quarter 2011 includes the following pre-tax items:

- $11 million gain related to the sale of our 50 percent interest in Accroven at Other (see Note 4);
- $11 million related to the reversal of project feasibility costs from expense to capital at Williams Partners (see Note 5).

Net income for first-quarter 2011 also includes a $124 million tax benefit related to finalized settlements and a revised assessment on an international matter (see Note 6).

THE WILLIAMS COMPANIES, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
STATEMENT OF COMPREHENSIVE INCOME (LOSS) (PARENT)

	Years Ended December 31,		
	2012	2011	2010
	(Millions, except per-share amounts)		
Equity in earnings of consolidated subsidiaries	$ 1,895	$ 1,962	$ 1,457
Interest incurred — external	(128)	(186)	(235)
Interest incurred — affiliate	(816)	(622)	(460)
Interest income — affiliate	84	84	76
Early debt retirement costs	—	(271)	(606)
Other income (expense) — net	3	(45)	(41)
Income from continuing operations before income taxes	1,038	922	191
Provision for income taxes	315	119	87
Income (loss) from continuing operations	723	803	104
Income (loss) from discontinued operations	136	(427)	(1,201)
Net income (loss)	$ 859	$ 376	$ (1,097)
Basic earnings (loss) per common share:			
Income (loss) from continuing operations	$ 1.17	$ 1.36	$ .17
Income (loss) from discontinued operations	.22	(.72)	(2.05)
Net income (loss)	$ 1.39	$ .64	$ (1.88)
Weighted-average shares (thousands)	619,792	588,553	584,552
Diluted earnings (loss) per share common share:			
Income (loss) from continuing operations	$ 1.15	$ 1.34	$ .17
Income (loss) from discontinued operations	.22	(.71)	(2.03)
Net income (loss)	$ 1.37	$ .63	$ (1.86)
Weighted-average shares (thousands)	625,486	598,175	590,699
Other comprehensive income (loss):			
Equity in other comprehensive income (loss) of consolidated subsidiaries	$ 21	$ 35	$ 121
Other comprehensive income (loss) attributable to The Williams Companies, Inc.	6	(123)	(35)
Other comprehensive income (loss)	27	(88)	86
Comprehensive income (loss) attributable to The Williams Companies, Inc.	$ 886	$ 288	$ (1,011)

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT — (Continued)

BALANCE SHEET (PARENT)

	December 31, 2012	December 31, 2011
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 340	$ 292
Other current assets	229	128
Total current assets	569	420
Investments in and advances to consolidated subsidiaries	16,686	13,602
Investment in Access Midstream Partners	2,187	—
Property, plant, and equipment — net	62	61
Other noncurrent assets	117	142
Total assets	$19,621	$14,225
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 29	$ 143
Long-term debt due within one year	1	28
Other current liabilities	122	58
Total current liabilities	152	229
Long-term debt	2,298	1,456
Notes payable — affiliates	8,938	8,418
Pension, other postretirement and other liabilities	712	732
Deferred income taxes	2,769	2,094
Contingent liabilities and commitments		
Equity:		
Common stock	716	626
Other stockholders' equity	4,036	670
Total stockholders' equity	4,752	1,296
Total liabilities and stockholders' equity	$19,621	$14,225

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT — (Continued)

STATEMENT OF CASH FLOWS (PARENT)

	Years Ended December 31, 2012	2011	2010
		(Millions)	
NET CASH FLOWS PROVIDED (USED) BY OPERATING ACTIVITIES	$ (11)	$ (286)	$ 3,371
FINANCING ACTIVITIES:			
Proceeds from long-term debt	848	75	100
Payments of long-term debt	(28)	(871)	(3,102)
Changes in notes payable to affiliates	520	(590)	1,422
Tax benefit of stock-based awards	44	22	7
Premiums paid on early debt retirement	—	(254)	(574)
Proceeds from issuance of common stock	2,550	49	12
Dividends paid	(742)	(457)	(284)
Other — net	(7)	(5)	(12)
Net cash provided (used) by financing activities	3,185	(2,031)	(2,431)
INVESTING ACTIVITIES:			
Capital expenditures	(18)	(28)	(15)
Purchase of investment in Access Midstream Partners	(2,179)	—	—
Changes in investments in and advances to consolidated subsidiaries	(953)	2,553	(2,054)
Other — net	24	(18)	—
Net cash provided (used) by investing activities	(3,126)	2,507	(2,069)
Increase (decrease) in cash and cash equivalents	48	190	(1,129)
Cash and cash equivalents at beginning of year	292	102	1,231
Cash and cash equivalents at end of year	$ 340	$ 292	$ 102

See accompanying notes.

Note 1. Guarantees

In addition to the guarantees disclosed in the accompanying consolidated financial statements in Item 8, we have financially guaranteed the performance of certain consolidated subsidiaries. The duration of these guarantees varies and we estimate the maximum undiscounted potential future payment obligation related to these 25 guarantees as of December 31, 2012, is approximately $1.5 billion.

Note 2. Cash Dividends Received

We receive dividends and distributions either directly from our subsidiaries or indirectly through dividends received by subsidiaries and subsequent transfers of cash to us through our corporate cash management system. The total of such receipts ultimately related to dividends and distributions for the years ended December 31, 2012, 2011 and 2010 was approximately $1.1 billion, $1.2 billion, and $5 billion, respectively.

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)			
2012					
Allowance for doubtful accounts — accounts and notes receivable (a)	$ 1	$—	$—	$ 1(f)	$—
Deferred tax asset valuation allowance (a)	145	(1)	—	—	144
2011					
Allowance for doubtful accounts — accounts and notes receivable (c)	15	1	—	15(g)	1
Deferred tax asset valuation allowance (b)	249	(33)	—	71(g)	145
2010					
Allowance for doubtful accounts — accounts and notes receivable (c)	22	(6)	—	1(f)	15
Deferred tax asset valuation allowance (b)	289	(40)	—	—	249
Price-risk management credit reserves — liabilities (d)	(3)	3(e)	—	—	—

(a) Deducted from related assets.

(b) Deducted primarily from related assets, with a portion included in assets of discontinued operations.

(c) Deducted from related assets, primarily included in assets of discontinued operations.

(d) Deducted from related liabilities, included in liabilities of discontinued operations.

(e) Included in *income (loss) from discontinued operations.*

(f) Represents balances written off, reclassifications, and recoveries.

(g) Includes balance deductions due to the spin-off of our exploration and production business on December 31, 2011.

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 Securities 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 2012 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 16, 2013 (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 *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 *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," "Compensation Committee Report on Executive Compensation," and "Compensation Committee Interlocks and Insider Participation" 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 accounting fees and services required by Item 9(e) of Schedule 14A will be presented under the heading "Principal Accountant Fees and Services" in Proposal 2 Ratification of the Appointment of Independent Auditors of our Proxy Statement, which information is incorporated by reference herein.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) 1 and 2.

All other schedules have been omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.

(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

INDEX TO EXHIBITS

Exhibit No.		Description
3.1	—	Amended and Restated Certificate of Incorporation, as supplemented (filed on May 26, 2010 as Exhibit 3.1 to the Company's Form 8-K (File No. 001-04174)) 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 (File No. 001-04174)) and incorporated herein by reference.
4.1	—	Senior Indenture dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee (filed September 14, 1995 as Exhibit 4.1 to Northwest Pipeline's Form S-3 (File No. 033-62639)) and incorporated herein by reference.
4.2	—	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 (File No. 333-02155)) and incorporated herein by reference.
4.3	—	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 (File No. 001-05254)) and incorporated herein by reference.

Exhibit No.		Description
4.4	—	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 (File No. 001-05254)) and incorporated herein by reference.
4.5	—	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 (File No. 333-35099)) and incorporated herein by reference.
4.6	—	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 (File No. 333-20837)) 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 (File No. 000-20555)) and incorporated herein by reference.
4.8	—	Supplemental Indenture No. 4 dated as of June 30, 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 (File No. 001-04174)) and incorporated herein by reference.
4.9	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.10	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.11	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.12	—	Indenture dated as of April 11, 2006, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee (filed on April 11, 2006 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K (File No. 001-07584)) and incorporated herein by reference.
4.13	—	Indenture dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee (filed on June 23, 2006 as Exhibit 4.1 to Northwest Pipeline's Form 8-K (File No. 001-07414)) and incorporated herein by reference.
4.14	—	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 (File No. 001-07414)) and incorporated herein by reference.
4.15	—	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 (File No. 001-07414)) and incorporated herein by reference.

Exhibit No.		Description
4.16	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.17	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.18	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.19	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.20	—	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 (File No. 001-07584)) and incorporated herein by reference.
4.21	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.22	—	Indenture, dated as of November 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on November 12, 2010 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
4.23	—	First Supplemental Indenture, dated as of November 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on November 12, 2010 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
4.24	—	Indenture dated as of August 12, 2011, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on August 12, 2011 as Exhibit 4.1 to Transcontinental Gas Pipe Line Company, LLC's Form 8-K (File No. 001-07584)) and incorporated herein by reference.
4.25	—	Second Supplemental Indenture, dated as of November 17, 2011, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed November 18, 2011 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
4.26	—	Indenture, dated as of July 13, 2012, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on July 16, 2012 as Exhibit 4.1 to Transcontinental Gas Pipe Line Company, LLC's current report on Form 8-K (File No. 001-07584)) and incorporated herein by reference.
4.27	—	Third Supplemental Indenture (including Form of 3.35% Senior Notes due 2022), dated as of August 14, 2012, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on August 14, 2012 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.

Exhibit No.		Description
4.28	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.29	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.30	—	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 (File No. 001-04174)) and incorporated herein by reference.
4.31	—	Indenture, dated December 18, 2012 between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. as trustee (filed on December 20, 2012 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K (File No. 001-04174)) and incorporated herein by reference.
4.32	—	First Supplemental Indenture, dated December 18, 2012, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. as trustee (filed on December 20, 2012 as Exhibit 4.2 to The Williams Companies, Inc.'s Form 8-K (File No. 001-04174)) 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 (File No. 001-04174)) and incorporated herein by reference.
10.2§	—	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 (File No. 001-04174)) and incorporated herein by reference.
10.3§	—	Form of 2011 Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 24, 2011 as Exhibit 10.6 to The Williams Companies, Inc.'s Form 10-K (File No. 001-04174)) and incorporated herein by reference.
10.4*§	—	Form of 2013 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers.
10.5*§	—	Form of 2013 Restricted Stock Unit Agreement among Williams and certain employees and officers.
10.6*§	—	Form of 2013 Nonqualified Stock Option Agreement among Williams and certain employees and officers.
10.7	—	Form of 2011 Restricted Stock Unit Agreement among Williams and nonmanagement directors (filed on February 27, 2012 as Exhibit 10.7 to The Williams Companies, Inc.'s Form 10-K (File No. 001-04174)) and incorporated herein by reference.
10.8	—	Form of 2012 Restricted Stock Unit Agreement among Williams and nonmanagement directors (filed on August 2, 2012 as Exhibit 10.2 to The Williams Companies, Inc.'s Form 10-Q (File No. 001-04174)) and incorporated herein by reference.
10.9	—	The Williams Companies, Inc. 1996 Stock Plan for Nonemployee Directors (filed on March 27, 1996 as Exhibit B to The Williams Companies, Inc.'s Proxy Statement (File No. 001-04174)) and incorporated herein by reference.
10.10§	—	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 (File No. 001-04174)) and incorporated herein by reference.

Exhibit No.		Description
10.11§	—	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 (File No. 001-04174)) and incorporated herein by reference.
10.12§	—	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 (File No. 001-04174)) and incorporated herein by reference.
10.13§	—	The Williams Companies, Inc. 2007 Incentive Plan as amended and restated effective January 19, 2012 (filed on May 1, 2012 as Exhibit 10.12 to The Williams Companies, Inc.'s Form 10-K/A (File No. 001-04174)) and incorporated herein by reference.
10.14*§	—	Amended and Restated Change-in-Control Severance Agreement between the Company and certain executive officers (Tier I Executives).
10.15§	—	Amended and Restated Change-in-Control Severance Agreement between the Company and certain executive officers (Tier II Executives) (filed on February 27, 2012, as Exhibit 10.14 to The Williams Companies, Inc.'s Form 10-K (File No. 001-04174)) and incorporated herein by reference.
10.16	—	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 (File No. 001-04174)) and incorporated herein by reference.
10.17	—	Credit Agreement, dated as of June 3, 2011, by and among The Williams Companies, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent (filed on August 4, 2011 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 10-Q (File No. 001-04174)) and incorporated herein by reference.
10.18	—	First Amendment to The Williams Companies, Inc. June 3, 2011 Credit Agreement, dated as of November 1, 2011, by and among The Williams Companies, Inc., the lenders named therein, and Citibank, N.A. as Administrative Agent (filed on November 1, 2011 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K (File No. 001-04174)) and incorporated herein by reference.
10.19	—	Credit Agreement, dated as of June 3, 2011, by and among Williams Partners L.P., Northwest Pipeline GP, Transcontinental Gas Pipe Line Company, LLC, as co-borrowers, the lenders named therein, and Citibank N.A., as Administrative Agent (filed on August 4, 2011 as Exhibit 10.2 to The Williams Companies, Inc.'s Form 8-K (File No. 001-04174)) and incorporated herein by reference.
10.20	—	Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (filed on February 27, 2012 as Exhibit 10.19 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference.
10.21	—	Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (filed on January 6, 2012 as Exhibit 10.2 to The Williams Companies, Inc.'s Form 8-K (File No. 001-04174)) and incorporated herein by reference.
10.22	—	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (filed on January 6, 2012 as Exhibit 10.3 to The Williams Companies, Inc.'s Form 8-K (File No. 001-04174)) and incorporated herein by reference.

Exhibit No.		Description
10.23	—	Contribution Agreement, dated as of March 19, 2012, between Caiman Energy, LLC and Williams Partners L.P. (filed on April 26, 2012 as Exhibit 10.1 to Williams Partners L.P.'s quarterly report on Form 10-Q (File No. 001-32599)) and incorporated herein by reference
10.24	—	First Amendment to Contribution Agreement, dated as of April 27, 2012, between Caiman Energy, LLC and Williams Partners L.P. (filed on August 2, 2012 as Exhibit 10.1 to Williams Partners L.P.'s quarterly report on Form 10-Q (File No. 001-32599)) and incorporated herein by reference.
10.25	—	Commitment Increase and First Amendment Agreement, dated as of September 25, 2012, by and among Williams Partners L.P., Northwest Pipeline GP and Transcontinental Gas Pipe Line Company, LLC, as co-borrowers, the lenders named therein, the Issuing Banks, and Citibank N.A., as administrative agent (filed on September 27, 2012 as Exhibit 10.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
10.26	—	Consulting Agreement and Release dated September 17, 2012, between The Williams Companies, Inc. and Phillip D. Wright (filed on October 31, 2012 as Exhibit 10.2 to The Williams Companies, Inc.'s Form 10-Q (File No. 001-04174)) and incorporated herein by reference
10.27	—	Contribution Agreement dated as of October 29, 2012, by and among The Williams Companies, Inc., Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC, and Williams Field Services Group, LLC (filed on November 2, 2012 as Exhibit 10.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
10.28*	—	Purchase Agreement dated as of December 11, 2012 with GIP-A Holding (CHK), L.P., GIP-B Holding (CHK), L.P. and GIP-C Holding (CHK), L.P.
10.29*	—	Subscription Agreement dated as of December 11, 2012 by and among Access Midstream Partners, L.P., Access Midstream Partners GP, L.L.C., GIP II Hawk Holdings Partnership, L.P. and The Williams Companies, Inc.
12*	—	Computation of Ratio of Earnings to Combined Fixed Charges.
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.
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.

Exhibit No.		Description
101.INS*	—	XBRL Instance Document
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

§ Management contract or compensatory plan or arrangement

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
Vice President, Controller and Chief Accounting Officer

Date: February 27, 2013

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 27, 2013
/s/ DONALD R. CHAPPEL Donald R. Chappel	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2013
/s/ TED T. TIMMERMANS Ted T. Timmermans	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2013
/s/ JOSEPH R. CLEVELAND* Joseph R. Cleveland*	Director	February 27, 2013
/s/ KATHLEEN B. COOPER* Kathleen B. Cooper*	Director	February 27, 2013
/s/ JOHN A. HAGG* John A. Hagg*	Director	February 27, 2013
/s/ JUANITA H. HINSHAW* Juanita H. Hinshaw*	Director	February 27, 2013
/s/ FRANK T. MACINNIS* Frank T. MacInnis*	Chairman of the Board	February 27, 2013
/s/ STEVEN W. NANCE* Steven W. Nance*	Director	February 27, 2013
/s/ MURRAY D. SMITH* Murray D. Smith*	Director	February 27, 2013

Signature	Title	Date
/s/ JANICE D. STONEY* Janice D. Stoney*	Director	February 27, 2013
/s/ LAURA A. SUGG* Laura A. Sugg*	Director	February 27, 2013
*By: /s/ SARAH C. MILLER Sarah C. Miller *Attorney-in-Fact*		February 27, 2013

Corporate Data

ANNUAL MEETING
Stockholders are invited to our annual meeting at 11 a.m. Central Time on May 16, 2013, 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 website.

Our investor relations group is available to answer questions about Williams. Call Sharna Reingold or John Porter at 918-573-2078 or 918-573-0797, 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
P.O. Box 1529
Tulsa, OK 74101

CERTIFICATIONS
We submitted the certification of Alan S. Armstrong, our Chief Executive Officer and President, to the New York Stock Exchange pursuant to NYSE Section 303A.12(a) on June 19, 2012.

We also filed with the Securities and Exchange Commission on February 27, 2013, as Exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the year ended December 31, 2012, 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 learn about Williams' corporate responsibility, go to www.williams.com.

Stockholder Information

WILLIAMS SECURITIES

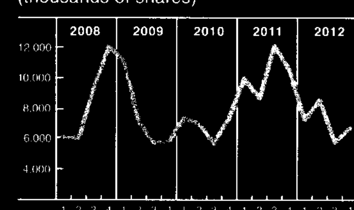
Williams common stock (WMB) is listed on the New York Stock Exchange.

The market value on Feb. 21, 2013 was approximately $23.2 billion. On that date, 8,843 shareholders of record held 681,532,705 shares of Williams common stock. The company's common stock traded at an average daily volume of 7.1 million shares in 2012.

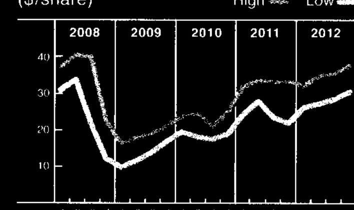
WILLIAMS COMMON STOCK ACTIVITY

A dividend of 12.5 cents per share was paid in the first quarter of 2011. A dividend of 20 cents per share was paid in the second and third quarters of 2011, and a dividend of 25 cents per share was paid in the fourth quarter of 2011. A dividend of 25.875 cents per share was paid in the first quarter of 2012, 30 cents per share in the second quarter, 31.25 cents per share in the third quarter, and 32.5 cents per share in the fourth quarter of 2012.

WMB AVERAGE DAILY VOLUMES TRADED
(thousands of shares)



WMB PRICE RANGES
($/share) High Low



WMB DAILY PRICES
($/share)

	2012		2011	
	High	Low	High	Low
1st Quarter	32.09	26.21	31.77	24.26
2nd Quarter	34.63	27.25	33.47	27.92
3rd Quarter	35.39	28.47	33.16	23.46
4th Quarter	37.56	30.55	33.11	21.90

(800) WILLIAMS | www.williams.com

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