WILLIAMS COMPANIES INC
Form 10-K
February 28, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011

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	*(IRS Employer*
Incorporation or Organization)	*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 x 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 x

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 x 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 x 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	x	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 x

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 $17,802,985,945.

The number of shares outstanding of the registrant s common stock outstanding at February 22, 2012 was 592,181,611.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s Definitive Proxy Statement for the Registrant s 2011 Annual Meeting of Stockholders to be held on May 17, 2012, are incorporated into Part III, as specifically set forth in Part III.

THE WILLIAMS COMPANIES, INC.

FORM 10-K

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DEFINITIONS

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

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

Bcf means one billion cubic feet.

Bcf/d means one billion cubic feet per day.

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

Dekatherms (Dth) means a unit of energy equal to one million Btus.

Mbbls/d means one thousand barrels per day.

Mdth/d means one thousand dekatherms per day.

MMBtu means one million Btus.

MMcf/d means one million cubic feet per day.

MMdth means one million dekatherms or approximately one trillion Btus.

MMdth/d: One million dekatherms per day.

TBtu means one trillion Btus.

Other definitions:

FERC means Federal Energy Regulatory Commission.

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

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

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

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

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

PART I

Item 1. ***Business***

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

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents electronically with the Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934, as amended (Exchange Act). You may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC s Internet website at 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 an energy infrastructure company focused on connecting North America s hydrocarbon resource plays to growing markets for natural gas, NGLs, and olefins. Our operations span from the deepwater Gulf of Mexico to the Canadian oil sands.

Our interstate gas pipeline and domestic midstream interests are largely held through its significant investment in Williams Partners L.P. (WPZ), one of the largest energy master limited partnerships. We own the general-partner interest and a 70 percent limited-partner interest in WPZ. We also own a Canadian midstream and domestic olefins production business, which processes oil sands off-gas and produces olefins for petrochemical feedstocks.

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.

SPIN-OFF OF WPX

On December 1, 2011, we announced that our Board of Directors approved a tax-free spinoff of 100 percent of our exploration and production business, WPX Energy, Inc. (WPX), to our shareholders. On December 31, 2011, we distributed one share of WPX common stock for every three shares of Williams common stock. As a result, with the exception of the December 31, 2011 balance sheet which no longer includes WPX, the consolidated financial statements reflect the results of operations and financial position of WPX as discontinued operations.

DIVIDEND GROWTH

We doubled our quarterly dividends from $0.125 per share in the fourth quarter of 2010 to $0.25 per share in the fourth quarter of 2011. Also, consistent with expected growing cash distributions from our interest in WPZ, we expect continued dividend increases on a quarterly basis. Our Board of Directors has approved a dividend of $0.25875 per share for the first quarter of 2012 and we expect total 2012 dividends to be $1.09 per share, which is approximately 41 percent higher than 2011.

RECENT EVENTS

In February 2012, Williams Partners completed the acquisition of 100 percent of the ownership interests in certain entities from Delphi Midstream Partners, LLC. 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 Williams Partners expansion in the Marcellus Shale by providing its customers with both operational flow assurance and marketing flexibility. (See Results of Operations - Segments, Williams Partners.)

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 2011 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 and is comprised of several wholly owned and partially owned subsidiaries and joint venture investments.

Midstream Canada & Olefins primarily our Canadian midstream and domestic olefins operations. Our Canadian operations include an oil sands off-gas processing plant located near Ft. 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. In the Gulf of Mexico region, we own a 5/6 interest in and are the operator of an NGL light-feed olefins cracker plant in Geismar, Louisiana. We also own ethane and propane pipelines systems in Louisiana that provide feedstock to the Geismar plant. Additionally, we own a refinery grade propylene splitter and associated pipeline. Our olefins business also operates an ethylene storage hub at Mont Belvieu using leased third-party underground storage wells.

Other primarily consists 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 3,000 TBtu of natural gas and peak-day delivery capacity of approximately 13 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 49 percent interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream). Our gas pipeline businesses contributed revenues of approximately 21 percent, 24 percent and 30 percent of *total revenues* in 2011, 2010, and 2009, respectively.

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, Pennsylvania, and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 11 southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, Washington, D.C., New York, New Jersey and Pennsylvania.

Pipeline system and customers

At December 31, 2011, Transco s system had a mainline delivery capacity of approximately 5.6 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 9.6 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 it owns and operates. The total usable gas storage capacity available to Transco and its customers in such underground storage fields and LNG storage facility and through storage service contracts is approximately 200 Bcf of natural gas. At December 31, 2011, our customers had stored in our facilities approximately 164 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 2011 or are future significant pipeline projects for which Transco has customer commitments.

Mobile Bay South II

The Mobile Bay South II Expansion Project involved the addition of compression at Transco s Station 85 in Choctaw County, Alabama, and modifications to existing facilities at Transco s Station 83 in Mobile County, Alabama, to allow Transco to provide additional firm transportation service southbound on the Mobile Bay line from Station 85 to various delivery points. The project was placed into service in May 2011 and provides incremental firm capacity of 380 Mdth/d.

85 North

The 85 North Expansion Project involved an expansion of Transco s existing natural gas transmission system from Station 85 in Choctaw County, Alabama, to various delivery points as far north as North Carolina. The first phase was placed into service in July 2010 and provides incremental firm capacity of 90 Mdth/d, and the second phase was placed into service in May 2011 and provides incremental firm capacity of 219 Mdth/d.

Mid-South

The Mid-South Expansion Project involves an expansion of Transco s mainline from Station 85 in Choctaw County, Alabama, to markets as far downstream as North Carolina. In August 2011, Transco received approval from the FERC. The capital cost of the project is estimated to be approximately $217 million. Transco plans to place the project into service in phases in September 2012 and June 2013, and it is expected to increase capacity by 225 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. In July 2011, Transco received approval from the FERC. The capital cost of the project is estimated to be approximately $55 million. Transco plans to place the project into service in November 2012, and it is expected to increase capacity by 142 Mdth/d.

Northeast Supply Link

In December 2011, Transco filed an application with 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 $341 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

The Rockaway Delivery Lateral Project involves the construction of a three-mile offshore lateral to a distribution system in New York. Transco anticipates filing an application with the FERC in 2012. The capital cost of the project is estimated to be approximately $182 million. Transco plans to place the project into service as early as April 2014, and its capacity is expected to be 647 Mdth/d.

Northeast Connector

The Northeast Connector Project involves expansion of Transco s existing natural gas transmission system from southeastern Pennsylvania to the proposed Rockaway Delivery Lateral. Transco anticipates filing an application with the FERC in 2012. The capital cost of the project is estimated to be approximately $39 million. Transco plans to place the project into service as early as April 2014, and its capacity is expected to be 100 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 California, Arizona, New Mexico, Colorado, Utah, Nevada, Wyoming, Idaho, Oregon, and Washington directly or indirectly through interconnections with other pipelines.

Pipeline system and customers

At December 31, 2011, Northwest Pipeline s system, having long-term firm transportation agreements including peaking service of approximately 3.8 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 477,000 horsepower.

Northwest Pipeline transports and stores natural gas for a broad mix of customers, including local natural gas distribution companies, municipal utilities, direct industrial users, electric power generators and natural gas marketers and producers. Northwest Pipeline s firm transportation and storage contracts are generally long-term contracts with various expiration dates and account for the major portion of Northwest Pipeline s business. Additionally, Northwest Pipeline offers interruptible and short-term firm transportation service.

Northwest Pipeline owns a one-third interest in the Jackson Prairie underground storage facility in Washington and contracts with a third party for storage service in the Clay basin underground field in Utah. Northwest Pipeline also owns and operates an LNG storage facility in Washington. These storage facilities have an aggregate working gas storage capacity of 13 Bcf of natural gas, which is substantially utilized for third-party natural gas, and firm delivery capability of approximately 700 MMcf/d enable Northwest Pipeline to provide storage services to its customers and to balance daily receipts and deliveries.

Northwest Pipeline expansion project

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 84 Mdth/d and 74 Mdth/d, respectively. The total estimated cost of the project is between $28 and $30 million. North Seattle is currently targeted for service in fall 2012 and 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 49 percent interest in Gulfstream while we own an additional 1 percent interest through a subsidiary in Other. 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.

Gulfstream Phase V

The Gulfstream Phase V expansion involved the addition of compression to provide 35 Mdth/d of incremental firm transportation capacity. The expansion was placed in service in April 2011.

Midstream Business

Williams Partners midstream business, one of the nation s largest natural gas gatherers and processors, has primary service areas concentrated in major producing basins in Colorado, New Mexico, Wyoming, the Gulf of Mexico, and Pennsylvania. The primary businesses are: (1) natural gas gathering, treating, and processing; (2) NGL fractionation, storage and transportation; and (3) oil transportation. 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;
- Prices impacting commodity-based activities.

The midstream business revenue contributed approximately 75 percent, 72 percent, and 65 percent of Williams Partners revenues in 2011, 2010, and 2009, respectively.

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, iso-butane 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. For the year ended December 31, 2011, 59 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 exposure to the difference between NGL prices and natural gas prices. For the year ended December 31, 2011, 38 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, 2011, 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 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 2011, Williams Partners facilities gathered and processed gas for approximately 210 gas gathering and processing customers. Williams Partners top 5 gathering and processing customers accounted for approximately 50 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, and Pennsylvania. 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, 2011:

		Natural Gas Gathering Assets			
	Location	**Pipeline Miles**	**Inlet Capacity (Bcf/d)**	**Ownership Interest**	**Supply Basins**
Onshore					
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	100%	Piceance
NE Pennsylvania	Pennsylvania	75	0.7	100%	Appalachian
Laurel Mountain (1)	Pennsylvania	1,386	0.2	51%	Appalachian
Gulf Coast					
Canyon Chief & Blind Faith	Deepwater Gulf of Mexico	139	0.4	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	319	0.6	60%	Central Gulf of Mexico

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

(2) In the first quarter of 2012, our Springville gathering pipeline was put into service, initially providing an optional takeaway for 0.3 Bcf/d of gas gathered on our system in northeast Pennsylvania. Also in the first quarter of 2012, 0.3 Bcf/d of capacity was added from the Laser gathering system acquisition.

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, 2011:

		Natural Gas Processing Facilities			
	Location	**Inlet Capacity (Bcf/d)**	**NGL Production Capacity (Mbbls/d)**	**Ownership Interest**	**Supply Basins**
Onshore					
Opal	Opal, WY	1.5	67	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
Lybrook (2)	Lybrook, NM	0.1	6	100%	San Juan
Willow Creek	Rio Blanco County, CO	0.5	30	100%	Piceance
Parachute	Garfield County, CO	1.4	7	100%	Piceance
Gulf Coast					
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 equity method investments that we operate, however our financial statements report equity method income from these investments based on our equity ownership percentage.
(2) Our Lybrook plant has been idled as of January 2012. Gas previously processed at Lybrook has been redirected to our Ignacio plant.

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, 2011:

		Crude Oil Pipelines		
	Pipeline Miles	**Handling 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, 2011:

	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 equity method investments that we operate, however our financial statements report equity method income from these investments based on our equity ownership percentage.

NGL marketing services

In addition to our gathering and processing operations, we market NGL products to a wide range of users in the energy and petrochemical industries. The NGL marketing business transports and markets equity NGLs from the production at 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 Producer Services LLC (Discovery). The NGL marketing business bears the risk of price changes in these NGL volumes while they are being transported to final sales delivery points. In order to meet sales contract obligations, 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 17 percent, 15 percent, and 9 percent of our consolidated revenues in 2011, 2010, and 2009, respectively.

Other 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 115 miles of pipelines in the Houston Shipping Channel area which transport a variety of products including ethane, propane and other products used in the petrochemical industry.

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 nearly 1,400 miles of pipeline with a capacity of approximately 230 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. The Shamrock compressor station currently has a capacity of 60 MMcf/d and is expandable to 350 MMcf/d.

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 in Conway, Kansas, along with 150- and 125-mile extensions into the Piceance and Denver-Joules basins in Colorado, respectively. Our equity NGL volumes from our two Wyoming plants and our Willow Creek facility in Colorado are dedicated for transport on OPPL under a long-term transportation agreement. We plan to participate 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.

Operating statistics

The following table summarizes our significant operating statistics for Midstream:

	2011	2010	2009
Volumes: (1)			
Gathering (Tbtu)	1,377	1,262	1,370
Plant inlet natural gas (Tbtu)	1,592	1,599	1,342
NGL production (Mbbls/d) (2)	189	178	164
NGL equity sales (Mbbls/d) (2)	77	80	80
Crude oil transportation (Mbbls/d) (2)	105	94	109

(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.

Midstream Canada & Olefins

The Midstream Canada & Olefins segment consists of our Canadian midstream business and our domestic olefins business. The segment contributed revenues of approximately 17 percent, 16 percent and 14 percent of our consolidated revenues in 2011, 2010 and 2009, respectively.

Midstream Canada

Our Canadian operations include an oil sands off-gas processing plant located near Ft. 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. We operate the Ft. 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 Ft. McMurray area facilities extract liquids from the off-gas produced by a third-party oil sands bitumen upgrading process. Our arrangement with the third-party upgrader is a keep-whole type where we remove a mix of NGLs and olefins from the off-gas and return the equivalent heating value to the third-party upgrader in the form of natural gas. 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 off-gas. Our extraction of liquids from upgrader off-gas streams allows the upgraders to burn cleaner natural gas streams and reduces their overall air emissions.

The Ft. McMurray extraction plant has processing capacity of 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. Our products are sold within Canada and the United States.

Canadian expansion projects

Construction is well underway on a 261-mile, 12-inch diameter Canadian pipeline which will transport recovered NGLs and olefins from our processing plant in Ft. McMurray to our Redwater fractionation facility. The pipeline, which will have an initial capacity of 43 Mbbls/d that can be increased to an ultimate capacity of 125 Mbbls/d with additional pump stations, will have sufficient capacity to transport additional NGLs and olefins from our existing operations as well as other NGLs and olefins produced from oil sands off-gas. The project is being constructed using cash previously generated from Canadian and other international projects. We anticipate an in-service date in second quarter of 2012.

Construction began in the fourth quarter of 2011 on the ethane recovery project that will allow us to recover ethane/ethylene mix from our operations that process off-gas from the Alberta oil sands. We are modifying our oil sands off-gas 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 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 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 the first quarter of 2013.

Domestic olefins

In the Gulf of Mexico region, we own a 5/6 interest in and are the operator of an NGL light-feed olefins cracker in Geismar, Louisiana, with a total production capacity of 1.35 billion pounds of ethylene and 90 million pounds of propylene per year. Our feedstocks for the cracker are ethane and propane; as a result, 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. Additionally, we own a refinery grade propylene splitter and associated pipeline with a production capacity of approximately 500 million pounds per year of propylene. At our propylene splitter, we purchase refinery grade propylene and fractionate it into polymer grade propylene and propane; as a result 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. Our olefins business also operates an ethylene storage hub at Mont Belvieu using leased third-party underground storage wells.

We own and operate 63 miles of pipeline in the Houston Ship Channel area which transport ammonia, tertiary butyl alcohol and other industrial gases for third parties. We also own a tunnel crossing pipeline under the Houston Ship Channel which contains multiple pipelines which are leased to third parties.

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

Domestic olefins expansion project

We are currently in the detailed engineering and procurement phase of an expansion of our Geismar olefins production facility which will 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. We expect to complete the expansion in the latter part of 2013.

Operating statistics

The following table summarizes our significant operating statistics for Midstream Canada & Olefins:

	2011	**2010**	**2009**
Volumes:			
Geismar ethylene sales (millions of pounds)	1,038	981	1,109
Canadian propylene sales (millions of pounds)	139	127	130
Canadian NGL sales (millions of gallons)	163	145	144

Additional Business Segment Information

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

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

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

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

REGULATORY MATTERS

Williams Partners

Gas Pipeline Business. Williams Partners gas pipeline s interstate transmission and storage activities are subject to FERC regulation under the Natural Gas Act of 1938 (NGA) and under the Natural Gas Policy Act of 1978, and, as such, its rates and charges for the transportation of natural gas in interstate commerce, its accounting, and the extension, enlargement or abandonment of its jurisdictional facilities, among other things, are subject to regulation. Each gas pipeline company holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities and properties for which certificates are required under the NGA. Each gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, and the Pipeline Safety Improvement Act of 2002, and the Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. FERC Standards of Conduct govern how our interstate pipelines communicate and do business with gas marketing employees. Among other things, the Standards of Conduct require that interstate pipelines not operate their systems to preferentially benefit gas marketing functions.

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

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

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

Pipeline Integrity Regulations

For Williams Partners gas pipeline business, Transco and Northwest Pipeline have developed an Integrity Management Plan that we believe meets the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) final rule that was issued pursuant to the requirements of the Pipeline Safety Improvement Act of 2002. The rule requires gas pipeline operators to develop an integrity management program for transmission pipelines that could affect high consequence areas in the event of pipeline failure. The Integrity Management Program includes a baseline assessment plan along with periodic reassessments to be completed within required timeframes. In meeting the integrity regulations, Transco and Northwest Pipeline have identified high consequence areas and developed baseline assessment plans. Transco and Northwest Pipeline are on schedule to complete the required assessments within required timeframes. Currently, Transco and Northwest Pipeline estimate the cost to complete the required initial assessments through 2012 and associated remediation will be primarily capital in nature and range between $25 million and $40 million for Transco and between $30 million and $35 million for Northwest Pipeline. Ongoing periodic reassessments and initial assessments of any new high consequence areas will be completed within the timeframes required by the rule. Management considers the costs associated with compliance with the rule to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through Transco s and Northwest Pipeline s rates.

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

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

The midstream business owns 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.

Midstream Canada & Olefins

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.

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

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

ENVIRONMENTAL MATTERS

Our operations are subject to federal environmental laws and regulations as well as the state, 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 *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,* Management s Discussion and Analysis of Financial Condition and Results of Operations Environmental and Environmental Matters in Note 16 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, but the changes implemented at the state level have not required renegotiation of LDC contracts. The state plans have in some cases discouraged LDCs from signing long-term contracts for new capacity.

States 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.

Midstream Canada & Olefins

Ethylene and propylene markets, and therefore our 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 depending on their market balances. Generally, we are viewed primarily as a supplier to these companies and not as a direct competitor. We compete on the basis of service, price and availability of the products we produce.

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

EMPLOYEES

At February 1, 2012, we had approximately 4,293 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, i objectives, targets, planned, potential, projects, scheduled, will or other similar expressions. These forward-looking statements ar 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;
- Seasonality of certain business components;
- Natural gas, natural gas liquids and crude oil prices and demand.

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this report. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Availability of supplies, 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 climate change regulation and changes in natural gas production from exploration and production areas that we serve), 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;
- Risks associated with future weather conditions;
- Acts of terrorism, including cybersecurity threats and related disruptions;
- Additional risks described in our filings with the Securities and Exchange Commission.

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

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

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

RISK FACTORS

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

Risks Related to the Spin-Off

The separation of our exploration and production business may not achieve its intended results.

The separation of our exploration and production business, completed on December 31, 2011, may not achieve its intended results and could have an adverse effect on us due to a number of factors. For example, the separation has significantly reduced the scope and scale of our business, we may not be able to grow as expected and we may incur proportionately higher costs to operate.

If there is a determination that the spin-off of 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.

Risks Related to our Business

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

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

Production from existing wells and natural gas supply basins with access to our pipeline 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, if development in new supply basins where we do not have significant gathering or pipeline systems reduces demand for our services, or if environmental regulators restrict new natural gas drilling, the overall volume of natural gas transported, gathered and stored on our system would decline, which could have a material adverse effect on our business, financial condition and results of operations. In addition, new LNG import facilities built near our markets could result in less demand for our gathering and transportation facilities.

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

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

Prices for NGLs, natural gas and other commodities, including oil, are volatile and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain 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, natural gas, oil, or other commodities, and the differences between prices of these commodities. Price volatility can impact both the amount we receive for our products and services and the volume of products and services we sell. Prices affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Any of the foregoing can also have an adverse effect on our business, results of operations, financial condition and cash flows.

The markets for NGLs, natural gas, 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, 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;
- 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;

The adoption of regulations or legislation relating to climate change and changes in natural gas production from exploration and production areas that we serve.

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 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.

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

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

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

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

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

The level of existing and new competition to deliver natural gas to our markets;

The growth in demand for natural gas in our markets;

Whether the market will continue to support long-term firm contracts;

Whether our business strategy continues to be successful;

The level of competition for natural gas supplies in the production basins serving us;

The effects of state regulation on customer contracting practices.

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

Our risk 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 the risk of financial loss in certain circumstances, including instances in which:

Volumes are less than expected;

The hedging instrument is not perfectly effective in mitigating the risk being hedged;

The counterparties to our hedging arrangements fail to honor their financial commitments.

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

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

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

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

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

We are exposed to the credit risk of our customers and 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.

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

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

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

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

- Hurricanes, tornadoes, floods, fires, extreme weather conditions, and other natural disasters;
- Aging infrastructure and mechanical problems;
- Damages to pipelines and pipeline blockages 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;

Risks related to truck and rail loading and unloading;

Risks related to operating in a marine environment;

Terrorist attacks or threatened attacks on our facilities or those of other energy companies.

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

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

We have experienced unexpected leaks or ruptures on one of our gas pipeline systems, including a rupture near Appomattox, Virginia in 2008 and a rupture near Sweet Water, Alabama in 2011. We could experience additional unexpected leaks or ruptures on our gas pipeline systems, or be required by regulatory authorities to test or undertake modifications to our systems that could result in a material adverse impact on our business, financial condition and results of operations if the costs of testing, maintaining or repairing our facilities exceed current expectations and the FERC or competition in our markets do not allow us to recover such costs in the rates we charge for our service. For example, in response to a recent third-party pipeline rupture, PHMSA issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. More recently, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 became law and under this statute PHMSA may issue additional regulations addressing such records. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipelines.

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

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

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

The ability to obtain necessary approvals and permits by regulatory agencies on a timely basis and on acceptable terms;

The availability of skilled labor, equipment, and materials to complete expansion projects;

Potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project;

Impediments on our ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms;

The ability to construct projects within estimated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control, that may be material;

The ability to access capital markets to fund construction projects.

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

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

We have defined benefit pension plans covering substantially all of our U.S. employees and other 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 interests is found to exist. Our control of the general partner of WPZ may increase the possibility of claims of breach of fiduciary duties, including claims brought due to conflicts of interest (including conflicts of interest that may arise between WPZ, on the one hand, and its general partner and that general partner s affiliates, including us, on the other hand). Any liability resulting from such claims could be material.

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

Regulators and legislators continue to take a renewed look at accounting practices, financial disclosures, and companies relationships with their independent public accounting firms. It remains unclear what new laws or regulations will be adopted, and we cannot predict the ultimate impact that any such new laws or regulations could have. In addition, the Financial Accounting Standards Board, the SEC or FERC could enact new accounting standards or FERC 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.

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, and financial condition and cash flows.

Risks Related to Strategy and Financing

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

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

Our failure to comply with the covenants in our debt agreements could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. Certain payment defaults or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements. For more information regarding our debt agreements, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Management s Discussion and Analysis of Financial Condition and Liquidity.

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

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

Our partnership interest in WPZ is one of our largest cash-generating assets. 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.

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.

A downgrade of our credit ratings could impact our liquidity, access to capital and our costs of doing business, and independent third parties outside 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, oil and other commodities;
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies;
- The overall health of the energy industry, including the bankruptcy or insolvency of other companies.

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

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 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 operationally, technical or financial problems;

Acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures.

Risks Related to Regulations that Affect Our Industry

Our gas pipelines could be subject to penalties and fines if they fail to comply with laws governing our businesses.

Our gas pipeline s transportation and storage operations are regulated by numerous governmental agencies including the FERC, the EPA and PHMSA. Should our gas pipelines fail to comply with all applicable statutes, rules, regulations and orders, they could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1,000,000 per day for each violation and under the recently enacted Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, PHMSA has civil penalty authority up to $200,000 per day (from the prior $100,000), with a maximum of $2 million for any related series of violations (from the prior $1 million). Any material penalties or fines under these or other statutes, rules, regulations or orders could have a material adverse impact on our gas pipeline business, financial condition, results of operations and cash flows.

The natural gas sales, transportation and storage operations of our gas pipelines are subject to regulation by the FERC, which could have an adverse impact on their ability to establish transportation and storage rates that would allow them to recover the full cost of operating their respective pipelines, including a reasonable rate of return.

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

- Transportation and sale for resale of natural gas in interstate commerce;
- Rates, operating terms, and conditions of service, including initiation and discontinuation of service;
- The types of services the gas pipelines may offer their customers;
- Certification and construction of new 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;
- Market manipulation in connection with interstate sales, purchases or transportation of natural gas.

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

Regulatory actions in these areas can affect our business in many ways, including decreasing tariff rates and revenues, decreasing volumes in our pipelines, increasing our costs and otherwise altering the profitability of our pipeline business.

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

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

We are subject to risks associated with climate change.

There is a growing belief that emissions of greenhouse gases (GHGs) may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks.

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

Numerous states and other jurisdictions have announced or adopted programs to stabilize and reduce GHGs. In 2009, the U.S. Environmental Protection Agency (EPA) issued a final determination that six GHGs are a threat to public safety and welfare. In 2011, the EPA implemented permitting for new and/or modified large sources of GHG emissions through the existing Prevention of Signification Deterioration permitting program. Additional direct regulation of GHG emissions in our industry may be implemented under other Clean Air Act programs, including the New Source Performance Standards program.

The recent actions of the EPA and the passage of any federal or state climate change laws or regulations could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities, and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or 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 and 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 and fractionation of NGLs, and as a result, we may be required to make substantial expenditures that could exceed current expectations. Our operations are subject to extensive federal, state, Native American, and local laws and regulations governing environmental protection, the discharge of materials into the environment and the security of chemical and industrial facilities. These laws include:

- Clean Air Act (CAA), and analogous state laws, which impose obligations related to air emissions;

- Clean Water Act (CWA), and analogous state laws, which regulate discharge of wastewaters and storm water from our facilities to state and federal waters, including wetlands;

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;

Resource Conservation and Recovery Act (RCRA), and analogous state laws, which impose requirements for the handling and discharge of solid and hazardous waste from our facilities.

Endangered Species Act (ESA), and analogous state laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species;

Oil Pollution Act (OPA) of 1990, which requires oil storage facilities and vessels to submit plans to the federal government detailing how they will respond to large discharges, regulates petroleum storage tanks and related equipment, and imposes liability for spills by responsible parties.

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, and the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases.

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, and 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, including CERCLA, RCRA, and analogous state laws, 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 non-compliance 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. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

In March 2010, the EPA announced its National Enforcement Initiatives for 2011 to 2013, which includes the addition of Energy Extraction Activities to its enforcement priorities list. To address its concerns regarding the pollution risks raised by new techniques for oil and gas extraction and coal mining, the EPA is developing an initiative to ensure that energy extraction activities are complying with federal environmental requirements. We cannot predict what the results of this initiative would be, or whether federal, state, or local laws or regulations will be enacted in this area. If regulations were imposed related to oil and gas extraction, the volumes of natural gas that we transport could decline and our results of operations could be adversely affected.

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. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our business, financial condition, results of operations and cash flows.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

Hydraulic fracturing is 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. Additional federal, state and local laws and regulations to more closely regulate hydraulic fracturing have been considered or implemented. Legislation to further regulate hydraulic fracturing has been proposed in Congress. The U.S. Department of Interior has announced plans to formalize obligations for disclosure of chemicals associated with hydraulic fracturing on federal lands. The results of a pending EPA investigation by a committee of the House of Representatives and two recent reports by the U.S. Department of Energy s Shale Gas Subcommittee could lead to further restrictions on hydraulic fracturing. The EPA has proposed regulations under the CAA regarding certain emissions from the hydraulic fracturing of oil and natural gas wells and announced its intention to propose regulations by 2014 under the CWA regarding wastewater discharges from hydraulic fracturing and other gas production. In addition, some state and local authorities have considered or imposed new laws and rules related to hydraulic fracturing, including additional permit requirements, operational restrictions, disclosure obligations and temporary or permanent bans on hydraulic fracturing in certain jurisdictions or in environmentally sensitive areas. 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 additional levels of reporting, regulation or permitting moratoria were 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.

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions 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. In addition, new environmental laws and regulations might adversely affect our products and activities, including fractionation, storage and transportation, as well as waste management and air emissions. For instance, federal and state agencies could impose additional safety requirements, any of which could affect our profitability.

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

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

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

Public and regulatory scrutiny of the energy industry has resulted in increased regulations being either proposed or implemented. 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 or increased permitting requirements. Current legal proceedings or other matters against us, including environmental matters, suits, regulatory appeals, challenges to our permits by citizen groups 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. Such scrutiny has also resulted in various inquiries, investigations and court proceedings in which we are a named defendant. Both the shippers on our pipelines and regulators have rights to challenge the rates we charge under certain circumstances. Any successful challenge could materially affect our results of operations.

In addition, existing regulations might be revised or reinterpreted, new laws, regulations and permitting requirements might be adopted or become applicable to us, our facilities our customers, our vendors or our service providers, and future changes in laws and regulations could have a material adverse effect on our financial condition, results of operations and cash flows. For example, various legislative and regulatory reforms associated with pipeline safety and integrity have been proposed recently, 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 the 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.

The 2010 drilling moratorium in the Gulf of Mexico and potentially more stringent regulations and permitting requirements on drilling in the Gulf of Mexico could adversely affect our operating results, financial condition and cash flows.

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

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

Institutional knowledge residing with current employees nearing retirement eligibility or with employees going to WPX as part of the separation of our exploration and production business 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, or with the loss of employees as part of the separation of our exploration and production business, we may not be able to replace them with employees of comparable knowledge and experience. In addition, we may not be able to retain or recruit other qualified individuals, and our efforts at knowledge transfer could be inadequate. If knowledge transfer, recruiting and retention efforts are inadequate, access to significant amounts of internal historical knowledge and expertise could become unavailable to us.

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

Some studies indicate a high failure rate of outsourcing relationships. A deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business. The expiration of such agreements or the transition of services between providers could lead to similar losses of institutional knowledge or disruptions.

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

Risks Related to Weather, other Natural Phenomena and Business Disruption

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

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

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

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

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

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 pipeline, 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, physical location or information otherwise known as social engineering.

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.

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 February 2012, the New Mexico Environmental Department and Williams Four Corner LLC settled alleged violations of the New Mexico Air Quality Act at five separate facilities that we own or operate for $164,000.

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 $44,300 and undertake certain supplemental environmental projects valued at $230,700.

Other

The additional information called for by this item is provided in Note 16 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 24, 2012, are listed below.

Alan S. Armstrong Age: 49	Director, Chief Executive Officer, and President

Position held since January 2011.

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

Randall L. Barnard Age: 53	Senior Vice President, Gas Pipeline

Position held since February 2011.

Mr. Barnard acts as President of our gas pipeline business. Mr. Barnard served as Vice President of Natural Gas Market Development from July 2010 to February 2011. From April 2002 to July 2010, Mr. Barnard was Senior Vice President of Operations and Technical Service for our gas pipeline business. From September 2000 to April 2002, he served as President of Williams International, Vice President and General Manager, and a director and from 2001 to 2002 Chief Executive Officer of Apco Oil and Gas International Inc., formerly Apco Argentina. From June 1997 to September 2000, Mr. Barnard was General Manager of Williams International in Venezuela. Mr. Barnard is a director and Senior Vice President, Gas Pipeline, of Williams Partners GP LLC, the general partner of WPZ, a Director of the Board of the Gas Technology Institute and Vice Chair of the Common Ground Alliance.

Donald R. Chappel Age: 60	Senior Vice President and Chief Financial Officer

Position held since April 2003.

Prior to joining us, Mr. Chappel held various financial, administrative and operational leadership positions. Mr. Chappel also serves as Chief Financial Officer and a director of Williams Partners GP LLC, the general partner of WPZ. He was Chief Financial Officer from August 2007 and a director from January 2008 of Williams Pipeline GP LLC, the general partner of 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) and is chairman of its finance committee.

Robyn L. Ewing Senior Vice President and Chief Administrative Officer
Age: 56

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, Midstream
Age: 51

Position held since January 2011.

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

Craig L. Rainey Senior Vice President and General Counsel
Age: 59

Position held since January 2012.

From February 2001 to December 2011, 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.

Ted T. Timmermans Vice President, Controller, and Chief Accounting Officer
Age: 55

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

Phillip D. Wright Senior Vice President, Corporate Development
Age: 56

Position held since February 2011.

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

Pipeline, of Williams Partners GP LLC, the general partner of WPZ from January 2010 to February 2011. Mr. Wright was appointed to the board of directors of Aegion Corporation (a provider of technologies and services for the rehabilitation of pipeline systems) in November 2011.

PART II

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

Our common stock is listed on the New York Stock Exchange under the symbol WMB. At the close of business on February 22, 2012, we had approximately 9,351 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:

		2011			2010	
Quarter	**High**	**Low**	**Dividend**	**High**	**Low**	**Dividend**
1st	$ 31.77	$ 24.26	$ 0.125	$ 23.76	$ 19.51	$ 0.11
2nd	$ 33.47	$ 27.92	$ 0.20	$ 24.66	$ 18.16	$ 0.125
3rd	$ 33.16	$ 23.46	$ 0.20	$ 21.00	$ 17.53	$ 0.125
4th	$ 33.11	$ 21.90	$ 0.25	$ 24.89	$ 18.88	$ 0.125

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, 2007. The Bloomberg U.S. Pipeline Index is composed of El Paso, Enbridge, Kinder Morgan, Spectra Energy, TransCanada Corp., and Williams. The graph below assumes an investment of $100 at the beginning of the period.

	2006	**2007**	**2008**	**2009**	**2010**	**2011**
The Williams Companies, Inc.	100.0	138.7	57.1	85.5	102.6	140.7
S&P 500 Index	100.0	105.5	66.5	84.1	96.7	98.8
Bloomberg U.S. Pipelines Index	100.0	118.5	72.4	102.6	126.2	174.1

The information presented in this Item has not 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, 2011 and 2010, and for each of the three years in the period ended December 31, 2011, 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. Certain amounts have been recast as a result of the December 31, 2011 spin-off of WPX. (See Note 1 of Notes to Consolidated Financial Statements.)

	2011	2010	2009	2008	2007
		(Millions, except per-share amounts)			
Revenues	$ 7,930	$ 6,638	$ 5,278	$ 6,904	$ 6,639
Income (loss) from continuing operations (1)	1,078	271	346	682	677
Amounts attributable to The Williams Companies, Inc.:					
Income (loss) from continuing operations	803	104	206	528	606
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	1.34	0.17	0.35	0.90	1.00
Total assets at December 31 (2)	16,502	24,972	25,280	26,006	25,061
Short-term notes payable and long-term debt due within one year at December 31	353	508	17	18	108
Long-term debt at December 31	8,369	8,600	8,259	7,683	7,579
Stockholders equity at December 31 (2)	1,793	7,288	8,447	8,440	6,375
Cash dividends declared per common share	0.775	0.485	0.44	0.43	0.39

(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 4 of Notes to Consolidated Financial Statements for further discussion of asset sales, impairments, and other accruals in 2011, 2010, and 2009.

(2) Total assets and stockholders equity for 2011 decreased due to the special dividend to spin off our former exploration and production business. See Note 2 of Notes to Consolidated Financial Statements for further information regarding the spin-off and the dividend.

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

General

We are primarily an energy infrastructure company focused on connecting North America s significant hydrocarbon resource plays to growing markets for natural gas, natural gas liquids, and olefins. Our operations are located principally in the United States, but span from the deepwater Gulf of Mexico to the Canadian oil sands, and are organized into the Williams Partners and Midstream Canada & Olefins reporting segments. All remaining business activities are included in Other. (See Note 1 of Notes to Consolidated Financial Statements for further discussion of these segments.) The Williams Partners segment consists of our consolidated master limited partnership, Williams Partners L.P. (WPZ), of which we currently own approximately 72 percent, including the general partner interest.

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.

Spin-off of WPX

On December 1, 2011, we announced that our Board of Directors approved a tax-free spinoff of 100 percent of our exploration and production business, WPX Energy, Inc. (WPX), to our shareholders. On December 31, 2011, we distributed one share of WPX common stock for every three shares of Williams common stock. As a result, with the exception of the December 31, 2011 balance sheet which no longer includes WPX, the consolidated financial statements reflect the results of operations and financial position of WPX as discontinued operations.

Dividend Growth

We doubled our quarterly dividends from $0.125 per share in the fourth quarter of 2010 to $0.25 per share in the fourth quarter of 2011. Also, consistent with expected growing cash distributions from our interest in WPZ, we expect continued dividend increases on a quarterly basis. Our Board of Directors has approved a dividend of $0.25875 per share for the first quarter of 2012 and we expect total 2012 dividends to be $1.09 per share, which is approximately 41 percent higher than 2011.

Overview

Crude oil and NGL prices increased in 2011, while natural gas prices have remained relatively low. We have benefited from this environment as our 2011 income (loss) from continuing operations attributable to The Williams Companies, Inc. increased by $699 million compared to 2010. This increase is primarily reflective of a $460 million improvement in operating profit and $335 million of lower charges associated with early debt retirements in 2011 as compared to 2010. See additional discussion in Results of Operations.

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 2011 through the present:

In March 2011, Midstream Canada & Olefins announced a long-term agreement under which it will produce up to 17,000 barrels per day of ethane/ethylene mix for a chemical company in Alberta, Canada. We plan to expand two primary facilities located in Alberta to support the new agreement. (See Results of Operations Segments, Midstream Canada & Olefins.)

In October 2011, Williams Partners executed an agreement with two significant producers to provide certain production handling services in the eastern deepwater Gulf of Mexico. We will design, construct and install a floating production system (Gulfstar FPS) that will have the capacity to handle 60 thousand barrels per day (Mbbls/d) of oil, up to 200 million cubic feet per day (MMcf/d) of natural gas, and the capability to provide seawater injection services. We expect Gulfstar FPS to be placed into service in 2014 and to be capable of serving as a central host facility for other deepwater prospects in the area. (See Results of Operations Segments, Williams Partners.)

During 2011, Williams Partners placed into service expansions of a natural gas transmission system, compression facilities, and line facilities that provide an aggregate additional 599 Mdth/d of incremental firm capacity. We also filed an application with the FERC to increase capacity by 250 Mdth/d by expanding our natural gas transmission system from the Marcellus Shale production region on the Leidy Line to various delivery points in New York and New Jersey. (See Results of Operations Segments, Williams Partners.)

In January 2012, Williams Partners placed into service our Springville pipeline that will allow us to initially deliver approximately 300 MMcf/d into the Transco pipeline and full use of approximately 650 MMcf/d of capacity from various compression and dehydration expansion projects to our gathering business in Pennsylvania s Marcellus Shale. (See Results of Operations Segments, Williams Partners.)

Discovery, an equity method investee in which we own 60 percent and operate, announced in January 2012 that it signed long-term agreements with anchor customers for natural gas gathering and processing services for production from the central deepwater Gulf of Mexico. To provide these services Discovery plans to construct a new deepwater pipeline which will have the capacity to flow approximately 400 MMcf/d and will accommodate the tie-in of other deepwater prospects. (See Results of Operations Segments, Williams Partners.)

In February 2012, Williams Partners completed the acquisition of 100 percent of the ownership interests in certain entities from Delphi Midstream Partners, LLC. 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 Williams Partners 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 February 2012, we announced a new interstate gas pipeline joint venture with Cabot Oil & Gas Corporation. 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 will own 75 percent of Constitution Pipeline. 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.

Outlook for 2012

We believe we are well positioned to execute on our 2012 business plan and to further realize our growth opportunities. Economic and commodity price indicators for 2012 and beyond reflect continued improvement in the economic environment. However, these measures can be volatile and it is reasonably possible that the economy could worsen and/or commodity prices could decline, negatively impacting our future operating results.

Our business plan for 2012 includes planned capital and investment expenditures of at least $3.4 billion, of which we expect to fund primarily through cash on hand, cash flow from operations, and debt and equity issuances by 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. We expect to realize our growth opportunities through these continued investments in our businesses in a way that meets customer needs and enhances our competitive position by:

- Continuing to invest in and grow our gathering, processing, and interstate natural gas pipeline systems;
- Retaining the flexibility to adjust somewhat our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.

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

- Availability of capital;
- General economic, financial markets, or industry downturn;
- Lower than anticipated energy commodity margins;
- Lower than expected levels of cash flow from operations;
- Counterparty credit and performance risk;
- Decreased volumes from third parties served by our midstream businesses;

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 disciplined investment strategies, commodity hedging strategies, and maintaining at least $1 billion in consolidated liquidity from cash and cash equivalents and unused revolving credit facilities.

Accounting Pronouncements Issued But Not Yet Adopted

Accounting pronouncements that have been issued but not yet adopted may have an effect on our Consolidated Financial Statements in the future.

See *Accounting Standards Issued But Not Yet Adopted* in Note 1 of Notes to Consolidated Financial Statements for further information on recently issued accounting standards.

Critical Accounting Estimate

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

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

	Benefit Expense		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Millions)			
Pension benefits:				
Discount rate	$ (8)	$ 9	$ (141)	$ 168
Expected long-term rate of return on plan assets	(10)	10		
Rate of compensation increase	2	(1)	10	(8)
Other postretirement benefits:				
Discount rate	(4)	5	(43)	53
Expected long-term rate of return on plan assets	(2)	2		
Assumed health care cost trend rate	6	(5)	47	(39)

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

In 2011, the fixed income exposure in the investment portfolios benefited while equities, particularly U.S. small capitalization stocks and international stocks, negatively impacted portfolio returns. While the 2011 investment performance did not meet 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. The 2011 actual return on plan assets for our pension plans was breakeven for the year. The ten-year average rate of return on pension plan assets through December 2011 was approximately 4.1 percent.

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

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

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

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, 2011. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2011	$ Change from 2010*	% Change from 2010*	2010 (Millions)	$ Change from 2009*	% Change from 2009*	2009
Revenues	$ 7,930	+1,292	+19%	$ 6,638	+1,360	+26%	$ 5,278
Costs and expenses:							
Costs and operating expenses	5,550	-838	-18%	4,712	-1,000	-27%	3,712
Selling, general and administrative expenses	325	-12	-4%	313	+17	+5%	330
Other (income) expense net	1	-16	NM	(15)	-19	-56%	(34)
General corporate expenses	187	+34	+15%	221	-57	-35%	164
Total costs and expenses	6,063			5,231			4,172
Operating income (loss)	1,867			1,407			1,106
Interest accrued net	(573)	+19	+3%	(592)	+3	+1%	(595)
Investing income net	168	-20	-11%	188	+150	NM	38
Early debt retirement costs	(271)	+335	+55%	(606)	-605	NM	(1)
Other income (expense) net	11	+23	NM	(12)	-14	NM	2
Income (loss) from continuing operations before income taxes	1,202			385			550
Provision (benefit) for income taxes	124	-10	-9%	114	+90	+44%	204
Income (loss) from continuing operations	1,078			271			346
Income (loss) from discontinued operations	(417)	+776	+65%	(1,193)	-1,208	NM	15
Net income (loss)	661			(922)			361
Less: Net income attributable to noncontrolling interests	285	-110	-63%	175	-99	-130%	76
Net income (loss) attributable to The Williams Companies, Inc.	$ 376			$ (1,097)			$ 285

* + = 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.

2011 vs. 2010

The increase in *revenues* is primarily due to higher marketing and NGL production revenues at Williams Partners as a result of higher average energy commodity prices, partially offset by a decrease in equity NGL production volumes. Additionally, fee revenues increased at Williams Partners primarily due to higher gathering, processing, and transportation fees. Midstream Canada & Olefins ethylene and Canadian NGL production revenues increased primarily resulting from higher average energy commodity prices and higher volumes.

The increase in *costs and operating expenses* is primarily due to increased costs associated with marketing purchases and operating costs at Williams Partners, partially offset by a decrease in NGL production costs. The higher marketing purchases are due to higher average energy commodity prices. Additionally, ethylene and NGL feedstock costs increased at Midstream Canada & Olefins reflecting higher average per-unit feedstock costs and higher volumes.

The unfavorable change in *other (income) expense net* within *operating income* 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 Midstream Canada & Olefins;
- $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 the Gulf Liquids litigation contingency accrual reduction in 2011 at Midstream Canada & Olefins (see Note 16 of Notes to Consolidated Financial Statements);
- $10 million related to the reversal of project feasibility costs from expense to capital in 2011 at Williams Partners (see Note 4 of Notes to Consolidated Financial Statements).

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

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 unfavorable change in *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 3 of Notes to Consolidated Financial Statements.) This decrease is partially offset by an increase of $12 million in equity earnings, primarily at Williams Partners related to an increased ownership interest in Overland Pass Pipeline Company LLC.

Early debt retirement costs in 2011 reflect costs related to corporate debt retirements in December 2011, including $254 million in related premiums. (See Note 11 of Notes to Consolidated Financial Statements.) *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 a $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 are now considered permanently reinvested. See Note 5 of Notes to Consolidated Financial Statements for a reconciliation of the effective tax rates compared to the federal statutory rate for both years.

Income (loss) from discontinued operations reflects the results of operations of our former exploration and production business as discontinued operations. See Note 2 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.

2010 vs. 2009

The increase in *revenues* is primarily due to higher marketing and NGL production revenues resulting from higher average energy commodity prices at Williams Partners. NGL and olefin production revenues at Midstream Canada & Olefins also increased due to higher average per-unit prices.

The increase in *costs and operating expenses* is primarily due to increased marketing purchases and NGL production costs at Williams Partners, reflecting higher average energy commodity prices. Additionally, NGL and olefin production costs at Midstream Canada & Olefins increased due to higher average per-unit feedstock costs.

Other (income) expense net within *operating income (loss)* in 2009 includes a $40 million gain on the sale of our Cameron Meadows NGL processing plant at Williams Partners.

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

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

The increase in *investing income net* is primarily due to the absence of a $75 million impairment charge in 2009 and a $43 million gain in 2010 on the sale of our 50 percent interest in Accroven at Other, and a $28 million increase in equity earnings at Williams Partners.

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

Other (income) expense net below *operating income (loss)* in 2010 includes an $8 million environmental expense accrual associated with former refinery operations.

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

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

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

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 and Gulf Coast regions of the United States. As of December 31, 2011, we own approximately 75 percent of the interests in WPZ, including the interests of the general partner, which is wholly owned by us, and incentive distribution rights.

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 2011

Significant events during 2011 include the following:

Laser Northeast Gathering System Acquisition

In February 2012, we acquired the Laser Northeast Gathering System and other midstream businesses from Delphi Midstream Partners, LLC for $325 million in cash, net of cash acquired in the transaction and subject to certain closing adjustments, and approximately 7.5 million of WPZ s common units. The Laser 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. As production in the Marcellus increases, the Laser system is expected to reach a capacity of 1.3 Bcf/d.

Marcellus Shale Gathering Asset Transition and Expansion

Our Springville pipeline was placed into service in January 2012, allowing us to deliver approximately 300 MMcf/d into the Transco pipeline. This new take-away capacity allows full use of approximately 650 MMcf/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. In conjunction with a long-term agreement with a significant producer, we are operating the 33-mile, 24-inch diameter natural gas gathering pipeline, connecting a portion of our gathering assets into the Transco pipeline. Expansions to the Springville compression facilities in 2012 are expected to increase the capacity to approximately 625 MMcf/d.

Construction of a new noncontiguous gathering system is complete and was placed into service in October 2011. This system currently has the capacity to deliver approximately 50 MMcf/d into a third-party interstate pipeline via the newly acquired Laser gathering system.

In early 2011, we assumed the operational activities for these gathering systems in northeastern Pennsylvania s Marcellus Shale which we acquired at the end of 2010. The acquired business included 75 miles of gathering pipelines and two compressor stations. We expect to expand this gathering system to a planned capacity of 1.7 Bcf/d by 2015.

Keathley Canyon Connector

Our equity investee, Discovery, plans to construct, own, and operate a new 215-mile 20-inch deepwater lateral pipeline for production from the Keathley Canyon Connector , Walker Ridge, and Green Canyon areas 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 those fields. The Keathley Canyon Connector lateral will originate from a third-party floating production facility in the southeast portion of the Keathley Canyon Connector area and will connect to Discovery s existing 30-inch offshore 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. Construction is expected to begin in 2013, with a mid-2014 in-service date.

Gulfstar FPS Deepwater Project

In October 2011, we executed agreements with two significant producers to provide production handling services for the Tubular Bells discovery located in the eastern deepwater Gulf of Mexico. The operator of the Tubular Bells field will utilize our proprietary floating-production system, Gulfstar FPS . We expect Gulfstar FPS to be capable of serving as a central host facility for other deepwater prospects in the area. We will design, construct, and install our Gulfstar FPS 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. The facility is a spar-based floating production system that utilizes a standard design approach that will allow customers to reduce their cycle time from discovery to first production. Construction is underway and the project is expected to be in service in 2014.

Eagle Ford Shale

We have completed construction on a pipeline segment and related modifications necessary to reverse the flow of an existing Transco pipeline segment in southwest Texas, which began to gather south Texas gas to our Markham gas processing facility in the second quarter of 2011. In addition, we connected a third-party pipeline to our Markham plant during the third quarter that is delivering Eagle Ford Shale gas to the plant. We have executed both fee-based and keep whole processing agreements which we expect will increase utilization of our Markham facility to the full gas processing capacity. Markham is subject to limited NGL take-away capacity until third-party pipeline connections are completed in early 2013.

Perdido Norte

During the fourth quarter of 2010, both oil and gas production began to flow on a sustained basis through our Perdido Norte expansion, located in the western deepwater of the Gulf of Mexico. The project included a 200 MMcf/d expansion of our Markham gas processing facility and a total of 179 miles of deepwater oil and gas lines that expand the scale of our existing infrastructure. While 2011 production volumes were significantly lower than originally expected, they have increased each quarter of 2011 as producers have resolved several technical issues. With these improvements and with the addition of a new well, we anticipate volumes in 2012 to be higher than in 2011.

Gulfstream

In May 2011, an entity reported within Other contributed a 24.5 percent interest in Gulfstream to WPZ in exchange for aggregate consideration of $297 million of cash, 632,584 limited partner units, and an increase in the capital account of WPZ s general partner to maintain the 2 percent general partner interest. Williams Partners now holds a 49 percent interest in Gulfstream. Prior period segment disclosures have not been adjusted for this transaction as the impact, which was less than 2.5 percent of Williams Partners segment profit for all periods affected, was not material.

Overland Pass Pipeline

We became the operator of OPPL effective April 1, 2011. We own a 50 percent interest in OPPL which includes a 760-mile NGL pipeline from Opal, Wyoming, to the Mid-Continent NGL market center in Conway, Kansas, along with 150- and 125-mile extensions into the Piceance and Denver-Julesburg basins in Colorado, respectively. Our equity NGL volumes from our two Wyoming plants and our Willow Creek plant in Colorado are dedicated for transport on OPPL under a long-term shipping agreement. We plan to participate 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.

Laurel Mountain

The initial phases of the Shamrock compressor station are in service, providing 60 MMcf/d of additional capacity, with further expansions planned in 2012. This compressor station is expandable to 350 MMcf/d and will likely be the largest central delivery point out of the Laurel Mountain system. Our equity investee continues to progress on further additions to the gathering infrastructure.

Volatile commodity prices

Average per-unit NGL margins in 2011 were significantly higher than in 2010, benefiting from a strong demand for NGLs resulting in higher NGL prices and slightly lower natural gas prices driven by abundant natural gas supplies.

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

85 North project

In September 2009, we received approval from the FERC to construct an expansion of our existing natural gas transmission system from Alabama to various delivery points as far north as North Carolina. Phase I was placed into service in July 2010 and it provides 90 thousand dekatherms per day (Mdth/d) of incremental firm capacity. Phase II was placed into service in May 2011 and it provides 219 Mdth/d of incremental firm capacity.

Mobile Bay South II project

In July 2010, we received approval from the FERC to construct additional compression facilities and modifications to existing Mobile Bay line facilities in Alabama allowing transportation service to various southbound delivery points. The project was placed into service in May 2011 and provides incremental firm capacity of 380 Mdth/d.

Outlook for 2012

The following factors could impact our business in 2012.

Commodity price changes

We expect our average per-unit NGL margins in 2012 to be comparable to 2011 and higher than our rolling five-year average per-unit NGL margins. NGL price changes have historically tracked somewhat with changes in the price of crude oil, although NGL, crude and natural gas prices are highly volatile, 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. Bolstered by abundant long-term domestic natural gas supplies, we expect to benefit from these dynamics in the broader global petrochemical markets.

As part of our efforts to manage commodity price risks on an enterprise basis, we continue to evaluate our commodity hedging strategies. To reduce the exposure to changes in market prices in 2012, we have entered into NGL swap agreements to fix the prices of approximately 5 percent of our anticipated NGL sales volumes and an approximate corresponding portion of anticipated shrink gas requirements for 2012. The combined impact of these energy commodity derivatives will provide a margin on the hedged volumes of $106 million. The following table presents our energy commodity hedging instruments as of February 15, 2012.

	Period	Volumes Hedged	Weighted Average Hedge Price (per gallon)
Designated as hedging instruments:			
NGL sales - isobutane (million gallons)	Feb - Dec 2012	12.8	$ 1.89
NGL sales - normal butane (million gallons)	Feb - Dec 2012	19.3	$ 1.79
NGL sales - natural gasoline (million gallons)	Feb - Dec 2012	29.0	$ 2.27
			(per MMbtu)
Natural gas purchases (Tbtu)	Feb - Dec 2012	6.5	$ 2.76

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.

In Williams Partners onshore midstream businesses, we anticipate significant growth in our gas gathering volumes as our infrastructure grows to support drilling activities in northeast Pennsylvania. We anticipate slight increases in gas gathering volumes in the Piceance basin and no change or slight declines in basins in the Rocky Mountain and Four Corners areas due to reduced drilling activity. We anticipate equity NGL volumes in 2012 to be comparable to 2011, as we expect little change in the volume of gas processed in the western onshore businesses. Sustained low gas prices could discourage producer drilling activities in our onshore areas and unfavorably impact the supply of natural gas available to gather and process in the long term.

In Williams Partners gulf coast businesses, we expect higher gas gathering, processing, and crude transportation volumes as production flowing through our Perdido Norte pipelines becomes consistent and other in-process drilling is completed. Increases in permitting, subsequent to the 2010 drilling moratorium, give us reason to expect gradual increased drilling activities in the Gulf of Mexico. In the Gulf Coast, our customers drilling activities are primarily focused on crude oil economics, rather than natural gas. We have not experienced, and do not anticipate an overall significant decline in volumes due to reduced drilling activities.

The operator of the third-party fractionator serving our NGL production transported on Overland Pass Pipeline has notified us of an expected 20- to 25-day outage in the second quarter of 2012 to accommodate their expansion efforts. The outage could result in a reduction to our equity volumes of up to approximately 20 million to 25 million gallons, along with price impacts; however we are evaluating methods to mitigate the impact.

We anticipate higher general and administrative, operating, and depreciation expense supporting our growing operations in northeast Pennsylvania, Piceance basin, and western Gulf of Mexico.

Expansion Projects

We have planned growth capital and investment expenditures of $2,305 million to $2,535 million in 2012. We plan to pursue expansion and growth opportunities in the Marcellus Shale region, Gulf of Mexico, and Piceance basin. Our ongoing major expansion projects include:

Marcellus Shale & Gulf of Mexico

As previously discussed, our ongoing major expansions to our gathering infrastructure in the Marcellus Shale region in northeastern Pennsylvania, including the acquisition of the Laser gathering system and related planned additions, expansions within our Laurel Mountain equity investment, also in the Marcellus Shale region, as well as our Gulfstar FPS floating production system and Discovery s Keathley Canyon Connector pipeline, both located in the Gulf of Mexico.

Parachute

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

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 $217 million. The project is expected to be phased into service in September 2012 and June 2013, with an expected increase in capacity of 225 Mdth/d.

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 cost of the project is estimated to be $55 million and is expected to increase capacity by 142 Mdth/d. We plan to place the project into service in November 2012.

Northeast Supply Link

In December 2011, we filed an application with 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 $341 million and is expected to increase capacity by 250 Mdth/d. We plan to place the project into service in November 2013.

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. We estimate the total abandonment costs, which will be capital in nature, will be approximately $76 million which is expected to be spent through the first half of 2013. Through December 31, 2011, we have incurred approximately $38 million in 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 14 of Notes to Consolidated Financial Statements.)

For the year ended December 31, 2011, we incurred approximately $15 million of expense related primarily to assessment and monitoring costs to ensure the safety of the surrounding area.

Filing of rate cases

During 2012, we expect to file rate cases for both Transco and Northwest Pipeline, which are expected to result in new transportation and storage rates beginning in 2013.

Year-Over-Year Operating Results

	Year ended December 31,		
	2011	2010	2009
		(Millions)	
Segment revenues	$ 6,729	$ 5,715	$ 4,602
Segment profit	$ 1,896	$ 1,574	$ 1,317

2011 vs. 2010

The increase in *segment revenues* includes:

A $589 million increase in marketing revenues primarily due to higher average NGL and crude 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 $103 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 during 2010 and 2011.

The increase in s*egment costs and expenses* of $725 million includes:

A $574 million increase in marketing purchases primarily due to higher average NGL and crude prices. These changes are offset by similar changes in marketing revenues.

A $136 million increase in operating costs reflecting $84 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 accelerated 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.

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:

$286 million of higher NGL production margins reflecting favorable commodity price changes.

A $103 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 during 2010 and 2011.

A $15 million increase in margins related to the marketing of NGLs and crude.

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 $136 million increase in operating costs as previously discussed.

A $30 million unfavorable change related to gains recognized in 2010 as previously discussed.

2010 vs. 2009

The increase in *segment revenues* includes:

- A $699 million increase in marketing revenues primarily due to higher average NGL and crude prices. These changes are more than offset by similar changes in marketing purchases.

- A $330 million increase in revenues associated with the production of NGLs reflecting an increase of $335 million associated with a 41 percent increase in average NGL per-unit sales prices.

- A $56 million increase in fee revenues primarily due to higher gathering revenue in the Piceance basin as a result of permitted increases in the cost-of-service gathering rate in 2010.

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

- A $721 million increase in marketing purchases primarily due to higher average NGL and crude prices. These changes are substantially offset by similar changes in marketing revenues.

A $107 million increase in costs associated with the production of NGLs reflecting an increase of $101 million associated with a 30 percent increase in average natural gas prices.

A $19 million increase in operating costs including $12 million higher depreciation primarily due to the new Perdido Norte pipelines and a full year of depreciation on our Willow Creek facility which was placed into service in the latter part of 2009.

The absence of a $40 million gain on the sale of our Cameron Meadows processing plant in 2009, partially offset by smaller gains in 2010. Gains recognized in 2010 include involuntary conversion gains due to insurance recoveries in excess of the carrying value of our gulf assets which were damaged by Hurricane Ike in 2008 and our Ignacio plant, which was damaged by a fire in 2007, as well as gains associated with sales of certain assets in Colorado s Piceance basin.

The increase in William Partners *segment profit* includes:

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

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

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

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

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

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

Midstream Canada & Olefins

Our Midstream Canada & Olefins segment includes our oil sands off-gas processing plant near Fort McMurray, Alberta, our NGL/olefin fractionation facility and butylene/butane (B/B) splitter facility at Redwater, Alberta, our NGL light-feed olefins cracker in Geismar, Louisiana along with associated ethane and propane pipelines, and our refinery grade propylene splitter in Louisiana. The products we produce are: NGLs, ethylene, propylene, and other co-products. Our NGL products include: propane, normal butane, isobutane/butylene (butylene), and condensate. Prior to the operation of the B/B splitter, we also produced and sold B/B mix product which is now separated and sold as butylene and normal butane.

Significant events for 2011

We signed a long-term agreement to initially produce 10,000 barrels per day (bbls/d) of ethane/ethylene mix for a third-party customer. We expect that we will ultimately increase our production of ethane/ethylene mix to 17,000 bbls/d and we expect to complete our expansions necessary to produce the initial barrels in the first quarter of 2013.

Outlook for 2012

The following factors could impact our business in 2012.

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 2011 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 $600 million to $700 million in 2012 on capital projects. The major expansion projects include:

The Boreal Pipeline project, which is a 12-inch diameter pipeline in Canada that will transport recovered NGLs and olefins from our extraction plant in Fort McMurray to our Redwater fractionation facility. The pipeline will have sufficient capacity to transport additional recovered liquids in excess of those from our current agreements. Construction is well underway and we anticipate an in-service date in the second quarter of 2012.

An expansion of our Geismar olefins production facility 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. We are currently in the detailed engineering and procurement phase and expect to complete the expansion in the latter part of 2013.

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 off-gas from the Alberta oil sands. We plan to modify our oil sands off-gas 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. As previously mentioned, we have signed a long-term contract to provide the ethane/ethylene mix to a third-party customer. Construction began in the fourth quarter of 2011 and we expect to complete the expansions and begin producing ethane/ethylene mix in the first quarter of 2013.

Year-Over-Year Operating Results

	Year ended December 31,		
	2011	2010	2009
		(Millions)	
Segment revenues	$ 1,312	$ 1,033	$ 753
Segment profit	$ 296	$ 172	$ 37

2011 vs. 2010

Segment revenues increased primarily due to:

$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.

$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 new 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 Canadian butylene and normal butane products primarily due to lower volume impact of operational and maintenance issues in 2011 as compared to 2010.

$37 million higher propylene production revenues due to $68 million higher revenues from 26 percent higher average per-unit sales prices, partially offset by $31 million lower revenues resulting from 10 percent lower overall propylene production sales volumes. The lower sales volumes were primarily due to the net impact of the following:

18 percent lower volumes at our Louisiana refinery grade propylene splitter primarily due to marketing and supply and third-party storage constraints, and customer outages. The impact of the lower propylene splitter sales was substantially offset by similar changes in related costs.

10 percent higher propylene sales volumes at our Canadian facility primarily due to lower volume impact of operational and maintenance issues in 2011 as compared to 2010.

$30 million higher butadiene and debutanized aromatic concentrate (DAC) production sales revenues primarily due to higher average per-unit sales prices.

Segment costs and expenses increased $155 million primarily as a result of:

$93 million higher ethylene feedstock costs resulting from higher average per-unit feedstock costs and 6 percent higher volumes.

$17 million higher operating and maintenance expenses primarily resulting from higher repairs and maintenance at our Canadian facilities and Geismar plant.

$14 million higher NGL feedstock costs primarily due to higher average per-unit feedstock costs on certain products and increased volumes on our Canadian butylene and normal butane products primarily due to reduced maintenance and operational issues.

$14 million higher propylene feedstock costs resulting from $36 million higher costs from 19 percent higher average per-unit feedstock costs, partially offset by $22 million lower costs related to reduced propylene feedstock volumes primarily from the lower volumes at our Louisiana refinery grade splitter described above.

$11 million higher butadiene and DAC feedstock costs primarily due to higher per-unit feedstock costs.

$6 million higher general and administrative costs.

The absence of a $6 million favorable customer settlement in 2010.

These increases were partially offset by $19 million of 2011 income related to the reduction of our accrual for the Gulf Liquids litigation. (See Note 16 of Notes to Consolidated Financial Statements.)

Segment profit increased primarily due to:

$42 million higher Canadian 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.

$33 million higher Geismar ethylene production margins due to 27 percent higher per-unit margins on 6 percent higher volumes.

$24 million higher Canadian propylene production margins resulting from 37 percent higher per-unit margins and 10 percent higher volumes.

$23 million higher Canadian propane production margins due to 37 percent higher per-unit margins and 5 percent higher volumes.

$19 million higher Geismar butadiene and DAC production margins primarily resulting from higher average per-unit margins.

$19 million of 2011 income related to the reduction of our accrual for the Gulf Liquids litigation. (See Note 16 of Notes to Consolidated Financial Statements.)

These increases were partially offset by $17 million higher operating and maintenance expenses, $6 million higher general and administrative costs and the absence of a $6 million favorable customer settlement in 2010.

2010 vs. 2009

Segment revenues increased primarily due to:

- $307 million higher NGL and olefins production revenues resulting from higher average per-unit prices. The new B/B splitter began producing and selling both butylene and normal butane in August 2010 and resulted in $22 million additional sales revenues over the 2009 B/B mix product sold. The separated products receive higher values in the marketplace than the B/B mix sold previously.

- $27 million higher marketing revenues due to general increases in energy commodity prices on slightly higher volumes. The higher marketing revenues were more than offset by similar changes in marketing purchases described below.

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

- 11 percent lower Geismar ethylene sales volumes, including the impact of a four-week plant maintenance outage at our Geismar plant during the fourth quarter of 2010.

- 12 percent lower propylene volumes sold primarily due to the absence of certain large 2009 propylene inventory sales and lower volumes available for processing at our Louisiana refinery grade propylene splitter.

Segment costs and expenses increased $145 million primarily as a result of:

- $156 million higher NGL and olefins production product costs resulting from higher average per-unit feedstock costs.

- $29 million increased marketing purchases due to general increases in energy commodity prices on slightly higher volumes. The increased marketing purchases more than offset similar changes in marketing revenues.

- $9 million higher operating and general and administrative costs.

Partially offsetting the increased costs are decreases due to:

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

- $6 million favorable customer settlement in 2010.

Segment profit increased primarily due to $139 million higher NGL and olefins production margins resulting from significantly higher average per-unit margins on lower volumes.

Other

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

Year-Over-Year Operating Results

	Year ended December 31, 2011	2010	2009
		(Millions)	
Segment revenues	$ 25	$ 24	$ 27
Segment profit (loss)	$ 24	$ 68	$ (41)

2011 vs. 2010

The unfavorable change in s*egment profit* 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 3 of Notes to Consolidated Financial Statements.) We are pursuing collection of these past due amounts from Petróleos de Venezuela S.A. (PDVSA), as well as claims related to the 2009 expropriation of certain of our Venezuelan operations, which are reported as discontinued operations.

2010 vs. 2009

The favorable change in s*egment profit* is primarily due to the net impact of recognizing $43 million in gains on the Accroven investment in 2010 while recording a $75 million impairment charge on that investment in 2009.

Management s Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2011, we continued to focus upon growth through disciplined investments in our businesses. Examples of this growth included:

- Continued investment in Williams Partners gathering and processing capacity and infrastructure in the Marcellus Shale area, western United States, and deepwater Gulf of Mexico. Included is a project to design, construct and install a floating production system (Gulfstar FPS) in the eastern deepwater Gulf of Mexico;
- Expansion of Williams Partners interstate natural gas pipeline system to meet the demand of growth markets;
- Expansion of Midstream Canada & Olefins facilities to increase production of an ethane/ethylene mix.

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

Our former exploration and production business, WPX, continued to invest in development drilling programs during 2011 that were largely self-funded through cash flow from operations. In November 2011, WPX completed the issuance of $1.5 billion of senior unsecured notes. WPX distributed $981 million of the net proceeds to us and retained approximately $500 million to fund future investments. Primarily utilizing the distribution we received related to the WPX debt issuance, we retired $746 million of debt in December 2011. We completed the tax-free spin-off of 100 percent of WPX to our shareholders on December 31, 2011.

During 2011, the economy has shown mixed signs of recovery; however, financial markets continue to be volatile as fears of global recession persist. In consideration of our liquidity in this environment, we note that, as of December 31, 2011, we have $889 million of cash and cash equivalents and $2.9 billion of available credit capacity under our credit facilities. Our $900 million and WPZ s $2 billion credit facilities do not expire until June 2016. (See additional discussion in the following Available Liquidity section.)

Outlook

Our plan for 2012 includes continued strong operating cash flows from our businesses. Lower-than-expected energy commodity prices would be somewhat mitigated by certain of our cash flow streams that are substantially insulated from short-term changes in commodity prices as follows:

- Firm demand and capacity reservation transportation revenues under long-term contracts from our gas pipelines;
- 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 payments while maintaining a sufficient level of liquidity. In particular, we note the following assumptions for 2012:

- We expect capital and investment expenditures to total between $3.4 billion and $3.8 billion in 2012. 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 $520 million and $600 million. Expansion capital expenditures, which are generally more discretionary to fund projects in order to grow our business are expected to total between $2.88 billion and $3.2 billion. See Results of Operations Segments, Williams Partners and Midstream Canada & Olefins for discussions describing the general nature of these expenditures;

- We expect to pay total cash dividends of approximately $1.09 per common share, an increase of 41 percent over 2011 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, debt payments, dividends, and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, utilization of our revolving credit facilities, and proceeds from debt issuances and sales of equity securities as needed. Based on a range of market assumptions, we currently estimate our cash flow from operations will be between $1.85 billion and $2.325 billion in 2012;

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

- We expect WPZ to fund its $325 million of current debt maturities with a new debt issuance;

- In January 2012, WPZ completed an equity issuance of 7 million common units representing limited partner interests in it at a price of $62.81 per unit. In February 2012, the underwriters exercised their option to purchase an additional 1.05 million common units for $62.81 per unit, with expected settlement on February 28, 2012;

- On February 17, 2012, Williams Partners 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 subject to certain closing adjustments, and approximately 7.5 million WPZ common units.

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 Midstream Canada & Olefins.

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 2012. Our internal and external sources of consolidated liquidity include cash generated from our operations, cash and cash equivalents on hand, and our credit facilities. Additional sources of liquidity, if needed, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. These sources are available to us at the parent level and are expected to be available to certain of our subsidiaries, particularly equity and debt issuances from WPZ. WPZ is expected to be self-funding through its cash flows from operations, use of its credit facility, and its access to capital markets. WPZ makes cash distributions to us in accordance with the partnership agreement, which considers our level of ownership and incentive distribution rights. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

	Expiration	WPZ	December 31, 2011 WMB (Millions)	Total
Available Liquidity				
Cash and cash equivalents		$ 163	$ 726 (1)	$ 889
Available capacity under our $900 million senior unsecured revolving credit facility (2)	June 3, 2016		900	900
Capacity available to WPZ under its $2 billion senior unsecured revolving credit facility (3)	June 3, 2016	2,000		2,000
		$ 2,163	$ 1,626	$ 3,789

(1) Includes $467 million of *cash and cash equivalents* that is being held by certain subsidiary and international operations and is not considered available for general corporate purposes. The remainder of our *cash and cash equivalents* is primarily held in government-backed instruments.

(2) In June 2011, we replaced our existing $900 million unsecured revolving credit facility agreement that was scheduled to expire in May 2012 with a new $900 million five-year senior unsecured revolving credit facility agreement. At December 31, 2011, we are in compliance with the financial covenants associated with this new credit facility agreement (see Note 11 of Notes to Consolidated Financial Statements).

(3) In June 2011, WPZ replaced its existing $1.75 billion unsecured revolving credit facility agreement that was scheduled to expire in February 2013 with a new $2 billion five-year senior unsecured revolving credit facility agreement. At December 31, 2011, WPZ is in compliance with the financial covenants associated with this new credit facility agreement. This credit facility is only available to WPZ, Transco and Northwest Pipeline as co-borrowers (see Note 11 of Notes to Consolidated Financial Statements).

In addition to the credit facilities listed above, we have issued letters of credit totaling $21 million as of December 31, 2011, under certain bilateral bank agreements.

WPZ filed a shelf registration statement as a well-known, seasoned issuer in February 2012 that allows it to issue an unlimited amount of registered debt and limited partnership unit securities.

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

As described in Note 11 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.

Credit Ratings

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

	WMB	WPZ
Standard and Poor s (1)		
Corporate Credit Rating	BBB-	BBB-
Senior Unsecured Debt Rating	BB+	BBB-
Outlook	Positive	Positive
Moody s Investors Service (2)		
Senior Unsecured Debt Rating	Baa3	Baa2
Outlook	Stable	Stable
Fitch Ratings (3)		
Senior Unsecured Debt Rating	BBB-	BBB-
Outlook	Stable	Positive

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

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

On February 27, 2012, Moody s Investors Service revised WMB s rating outlook to stable from negative.

On February 27, 2012, Moody s Investors Service upgraded WPZ s senior unsecured debt rating to Baa2 from Baa3. The rating outlook was also revised to stable from under review for possible upgrade.

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

On February 9, 2012, Fitch Ratings revised WMB s outlook to stable from rating watch negative. WPZ s outlook was also revised to positive from stable.

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, 2011, we estimate that a downgrade to a rating below investment grade for us or WPZ could require us to post up to $165 million or $134 million, respectively, in additional collateral with third parties.

Sources (Uses) of Cash

	Years Ended December 31,		
	2011	**2010**	**2009**
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 3,439	$ 2,651	$ 2,572
Financing activities	(342)	573	166
Investing activities	(3,003)	(4,296)	(2,310)
Increase (decrease) in cash and cash equivalents	$ 94	$ (1,072)	$ 428

Operating activities

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

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

Financing activities

Significant transactions include:

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 in 2011.

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 previously discussed 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.

2009

We received $595 million net cash from the issuance of $600 million aggregate principal amount of 8.75 percent senior unsecured notes due 2020 to fund general corporate expenses and capital expenditures;

We paid $256 million of quarterly dividends on common stock for the year ended December 31, 2009.

Investing activities

Significant transactions include:

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.

2009

- Capital expenditures totaled $2.4 billion, more than half of which related to our former exploration and production businesses. Included was a $253 million payment by our former exploration and production business for the purchase of additional properties in the Piceance basin;
- We received $148 million as a distribution from Gulfstream following its debt offering;
- We contributed $142 million to our investments, including $106 million related to our Laurel Mountain equity investment and $20 million related to our Gulfstream equity investment.

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

We have various other guarantees and commitments which are disclosed in Notes 9, 11, 15 and 16 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations at December 31, 2011:

	2012	2013 - 2014	2015 - 2016 (Millions)	Thereafter	Total
Long-term debt, including current portion:					
Principal	$ 352	$	$ 1,125	$ 7,272	$ 8,749
Interest	530	1,000	934	4,434	6,898
Capital leases	2	2			4
Operating leases (1)	44	69	55	148	316
Purchase obligations (2)	1,626	648	418	1,320	4,012
Other long-term liabilities (3) (4)		1	1		2
Total	$ 2,554	$ 1,720	$ 2,533	$ 13,174	$ 19,981

(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 2013 and thereafter does not include such variable amounts related to this agreement as the variable amount is not yet determinable.

(2) Includes an estimated $2.2 billion long-term ethane purchase obligation with index-based pricing terms that is reflected in this table at December 31, 2011 prices. This obligation is part of an overall exchange agreement whereby volumes we transport on OPPL are sold at a third-party fractionator in 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.

(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 $83 million in 2011 and $76 million in 2010. In 2012, we expect to contribute approximately $94 million to these plans (see Note 7 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 2011, we contributed $60 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 2012, we expect to contribute approximately $70 million to our tax-qualified pension plans and use excess amounts to satisfy minimum contribution requirements. 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 5 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 58 percent of our gross property, plant, and equipment is comprised of our interstate gas pipelines. These assets are subject to regulation, which limits recovery to historical cost. While amounts in excess of historical cost are not recoverable under current FERC practices, we anticipate being allowed to recover and earn a return based on increased actual cost incurred to replace existing assets. Cost-based regulation, along with competition and other market factors, may limit our ability to recover such increased costs. For the remainder of our business, operating costs are influenced to a greater extent by both competition for specialized services and specific price changes in crude oil and natural gas and related commodities than by changes in general inflation. Crude oil, natural gas, and NGL prices are particularly sensitive to the Organization of the Petroleum Exporting Countries (OPEC) production levels and/or the market perceptions concerning the supply and demand balance in the near future, as well as general economic conditions. However, our exposure to certain of these price changes is reduced through the use of hedging instruments and the fee-based nature of certain of our services.

Environmental

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations and/or remedial processes at certain sites, some of which we currently do not own (see Note 16 of Notes to Consolidated Financial Statements). We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Current estimates of the most likely costs of such activities are approximately $47 million, all of which are included in *accrued liabilities* and *regulatory liabilities, deferred income and other* on the Consolidated Balance Sheet at December 31, 2011. 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 2011, we paid approximately $8 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $10 million in 2012 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, 2011, certain assessment studies were still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type, and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

We are also subject to the Federal Clean Air Act (Act) and to the Federal Clean Air Act Amendments of 1990 (1990 Amendments), which added significantly to the existing requirements established by the Act. Pursuant to requirements of the 1990 Amendments and EPA rules designed to mitigate the migration of ground-level ozone, we have installed air pollution controls on existing sources at certain facilities in order to reduce ozone emissions.

In March 2008, the EPA promulgated a new, lower National Ambient Air Quality Standard (NAAQS) for ground-level ozone. Within two years, the EPA was expected to designate new eight-hour ozone nonattainment areas. However, in September 2009, the EPA announced it would reconsider the 2008 NAAQS for ground level ozone to ensure that the standards were clearly grounded in science and were protective of both public health and the environment. As a result, the EPA delayed designation of new eight-hour ozone 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 it would not move forward with the proposed 2010 ozone NAAQS. Instead, the EPA will implement the 2008 ozone NAAQS that was stayed during the reconsideration process. The EPA is expected to designate ozone nonattainment areas under the 2008 NAAQS in second quarter 2012 and we are unable at this time to estimate the cost of additions that may be required to meet this new regulation. However, designation of new eight-hour ozone nonattainment areas are expected to result in additional federal and state regulatory actions that will likely impact our operations and increase the cost of additions to *property, plant and equipment net* on the Consolidated Balance Sheet.

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 $24 million to $32 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. This new standard is subject to challenge in federal court. 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.

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

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

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

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. Our debt portfolio is 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 11 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, 2011 and 2010. 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.

	2012	2013	2014	2015	2016 (Millions)	Thereafter(1)	Total	Fair Value December 31, 2011
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%		

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

(1) Includes unamortized discount and premium.
(2) Excludes capital leases.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas and NGLs, 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 15 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. The fair value of our trading derivatives was a net asset of less than $0.1 million at December 31, 2011. The value at risk for contracts held for trading purposes was less than $0.1 million at December 31, 2011 and zero at December 31, 2010.

Nontrading

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

Segment	Commodity Price Risk Exposure
Williams Partners	Natural gas purchases NGL sales
Midstream Canada & Olefins	NGL purchases and sales

The fair value of our nontrading derivatives was a net asset of $1 million at December 31, 2011.

The value-at-risk for derivative contracts held for nontrading purposes was zero at December 31, 2011, and 2010. During the year ended December 31, 2011, our value at risk for these contracts ranged from a high of $1 million to a low of zero.

Certain of the derivative contracts held for nontrading purposes in 2011 were accounted for as cash flow hedges but realized during the year. Of the total fair value on nontrading derivatives, cash flow hedges had a net asset value of zero as of December 31, 2011. Though these contracts would be included in our value-at-risk calculation, any changes in the fair value of the effective portion of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Trading Policy

We have policies and procedures that govern our trading and risk management activities. These policies cover authority and delegation thereof in addition to control requirements, authorized commodities, and term and exposure limitations.

Foreign Currency Risk

Net assets of our consolidated foreign operations, whose functional currency is the local currency, are located primarily in Canada were approximately $690 million and $580 million at December 31, 2011 and 2010, respectively. These foreign operations do not have significant transactions or financial instruments denominated in currencies other than their functional currency. However, these investments do have the potential to impact our financial position, due to fluctuations in these local currencies arising from the process of translating the local functional currency into the U.S. dollar. As an example, a 20 percent change in the respective functional currencies against the U.S. dollar would have changed *stockholders equity* by approximately $138 million at December 31, 2011.

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, 2011, 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, 2011, 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, 2011, 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, 2011, 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, 2011 and 2010, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2011, of The Williams Companies, Inc. and our report dated February 27, 2012, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 27, 2012

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, 2011 and 2010, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2011. 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 two percent of the Company s assets as of both December 31, 2011 and 2010 and the Company s equity earnings in the net income of Gulfstream constituted five and seventeen percent of the Company s income from continuing operations before income taxes for the years ended December 31, 2011 and 2010, respectively, Gulfstream s financial statements were audited by other auditors whose report has been furnished to us, and our opinion on the 2011 and 2010 consolidated financial statements, 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, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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, 2012, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 27, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the balance sheet of Gulfstream Natural Gas System, L.L.C., (the Company), as of December 31, 2011 and 2010, and the related statements of operations, cash flows, and members equity and comprehensive income for the years then ended. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, such financial statements present fairly, in all material respects, the financial position of Gulfstream Natural Gas System, L.L.C. as of December 31, 2011 and 2010, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas

February 23, 2012

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF OPERATIONS

	Years Ended December 31,		
	2011	**2010**	**2009**
		(Millions, except per-share amounts)	
Revenues:			
Williams Partners	$ 6,729	$ 5,715	$ 4,602
Midstream Canada & Olefins	1,312	1,033	753
Other	25	24	27
Intercompany eliminations	(136)	(134)	(104)
Total revenues	7,930	6,638	5,278
Segment costs and expenses:			
Costs and operating expenses	5,550	4,712	3,712
Selling, general, and administrative expenses	325	313	330
Other (income) expense net	1	(15)	(34)
Total segment costs and expenses	5,876	5,010	4,008
General corporate expenses	187	221	164
Operating income (loss):			
Williams Partners	1,754	1,465	1,236
Midstream Canada & Olefins	300	172	37
Other		(9)	(3)
General corporate expenses	(187)	(221)	(164)
Total operating income (loss)	1,867	1,407	1,106
Interest accrued	(598)	(628)	(656)
Interest capitalized	25	36	61
Investing income net	168	188	38
Early debt retirement costs	(271)	(606)	(1)
Other income (expense) net	11	(12)	2
Income (loss) from continuing operations before income taxes	1,202	385	550
Provision (benefit) for income taxes	124	114	204
Income (loss) from continuing operations	1,078	271	346
Income (loss) from discontinued operations	(417)	(1,193)	15
Net income (loss)	661	(922)	361
Less: Net income attributable to noncontrolling interests	285	175	76
Net income (loss) attributable to The Williams Companies, Inc.	$ 376	$ (1,097)	$ 285
Amounts attributable to The Williams Companies, Inc.:			
Income (loss) from continuing operations	$ 803	$ 104	$ 206
Income (loss) from discontinued operations	(427)	(1,201)	79
Net income (loss)	$ 376	$ (1,097)	$ 285

Basic earnings (loss) per common share:			
Income (loss) from continuing operations	$ 1.36	$ .17	$ .35
Income (loss) from discontinued operations	(.72)	(2.05)	.14
Net income (loss)	$ .64	$ (1.88)	$ .49
Weighted-average shares (thousands)	588,553	584,552	581,674
Diluted earnings (loss) per common share:			
Income (loss) from continuing operations	$ 1.34	$ .17	$ .35
Income (loss) from discontinued operations	(.71)	(2.03)	.14
Net income (loss)	$ .63	$ (1.86)	$ .49
Weighted-average shares (thousands)	598,175	590,699	585,955

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

	December 31, 2011	December 31, 2010
	(Millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 889	$ 758
Accounts and notes receivable (net of allowance of $1 at December 31, 2011 and 2010, respectively)	637	497
Inventories	169	225
Assets of discontinued operations		897
Regulatory assets	40	51
Other current assets and deferred charges	159	102
Total current assets	1,894	2,530
Investments	1,391	1,240
Property, plant, and equipment net	12,580	11,754
Assets of discontinued operations		8,828
Regulatory assets, deferred charges, and other	637	620
Total assets	$ 16,502	$ 24,972
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 691	$ 432
Accrued liabilities	631	738
Liabilities of discontinued operations		896
Long-term debt due within one year	353	508
Total current liabilities	1,675	2,574
Long-term debt	8,369	8,600
Deferred income taxes	1,660	1,738
Liabilities of discontinued operations		2,179
Regulatory liabilities, deferred income, and other	1,715	1,262
Contingent liabilities and commitments (Note 16)		
Equity:		
Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 626 million shares issued at December 31, 2011 and 620 million shares issued at December 31, 2010)	626	620
Capital in excess of par value	8,417	8,269
Retained deficit	(5,820)	(478)
Accumulated other comprehensive income (loss)	(389)	(82)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders equity	1,793	7,288
Noncontrolling interests in consolidated subsidiaries	1,290	1,331
Total equity	3,083	8,619
Total liabilities and equity	$ 16,502	$ 24,972

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	The Williams Companies, Inc., Stockholders							
	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss	Treasury Stock	Total Stockholders Equity	Noncontrolling Interest	Total
	(Millions, except per-share amounts)							
Balance, December 31, 2008	$ 613	$ 8,074	$ 874	$ (80)	$ (1,041)	$ 8,440	$ 614	$ 9,054
Comprehensive income (loss):								
Net income (loss)			285			285	76	361
Other comprehensive income (loss):								
Net change in cash flow hedges (Note 17)				(221)		(221)		(221)
Foreign currency translation adjustments				83		83		83
Pension benefits:								
Net actuarial gain (loss)				46		46	7	53
Other postretirement benefits:								
Prior service cost				4		4		4
Total other comprehensive income (loss)						(88)	7	(81)
Total comprehensive income (loss)						197	83	280
Cash dividends common stock (Note 12)			(256)			(256)		(256)
Dividends and distributions to noncontrolling interests							(129)	(129)
Issuance of common stock from debentures conversion (Note 12)	3	25				28		28
Stock-based compensation, net of tax benefit	2	36				38		38
Other							4	4
Balance, December 31, 2009	618	8,135	903	(168)	(1,041)	8,447	572	9,019
Comprehensive income (loss):								
Net income (loss)			(1,097)			(1,097)	175	(922)
Other comprehensive income (loss):								
Net change in cash flow hedges (Note 17)				92		92		92
Foreign currency translation adjustments				29		29		29
Pension benefits:								
Prior service cost				1		1		1
Net actuarial gain (loss)				(25)		(25)		(25)
Other postretirement benefits:								
Prior service cost				(3)		(3)		(3)
Net actuarial gain (loss)				(8)		(8)		(8)
Total other comprehensive income (loss)						86		86
Total comprehensive income (loss)						(1,011)	175	(836)
Cash dividends common stock (Note 12)			(284)			(284)		(284)
Dividends and distributions to noncontrolling interests							(145)	(145)
Issuance of common stock from debentures conversion (Note 12)		2				2		2
Sale of limited partner units of consolidated partnership							806	806
Stock-based compensation, net of tax benefit	2	55				57		57

Changes in Williams Partners L.P. ownership interest, net		77				77	(77)	
Balance, December 31, 2010	620	8,269	(478)	(82)	(1,041)	7,288	1,331	8,619

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THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (Continued)

	The Williams Companies, Inc., Stockholders							
	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss	Treasury Stock	Total Stockholders Equity	Noncontrolling Interest	Total
	(Millions, except per-share amounts)							
Balance, December 31, 2010	620	8,269	(478)	(82)	(1,041)	7,288	1,331	8,619
Comprehensive income (loss):								
Net income (loss)			376			376	285	661
Other comprehensive income (loss):								
Net change in cash flow hedges (Note 17)				53		53		53
Foreign currency translation adjustments				(18)		(18)		(18)
Pension benefits:								
Prior service cost				1		1		1
Net actuarial gain (loss)				(112)		(112)		(112)
Other postretirement benefits:								
Prior service cost				(2)		(2)		(2)
Net actuarial gain (loss)				(13)		(13)		(13)
Unrealized gain (loss) on equity securities				3		3		3
Total other comprehensive income (loss)						(88)		(88)
Total comprehensive income (loss)						288	285	573
Cash dividends common stock (Note 12)			(457)			(457)		(457)
Dividends and distributions to noncontrolling interests							(214)	(214)
Issuance of common stock from debentures conversion (Note 12)	1	13				14		14
Stock-based compensation, net of tax benefit	4	104				108		108
Changes in Williams Partners L.P. ownership interest, net		30				30	(30)	
Distribution of WPX Energy, Inc. to shareholders (Note 2)			(5,261)	(219)		(5,480)	(81)	(5,561)
Other	1	1				2	(1)	1
Balance, December 31, 2011	$ 626	$ 8,417	$ (5,820)	$ (389)	$ (1,041)	$ 1,793	$ 1,290	$ 3,083

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31,		
	2011	2010	2009
		(Millions)	
OPERATING ACTIVITIES:			
Net income (loss)	$ 661	$ (922)	$ 361
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, depletion, and amortization	1,614	1,507	1,469
Provision (benefit) for deferred income taxes	(179)	(155)	249
Provision for loss on goodwill, investments, property and other assets	882	1,735	386
Provision for doubtful accounts and notes	1	(6)	48
Amortization of stock-based awards	52	48	43
Early debt retirement costs	271	606	1
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	(197)	(36)	52
Inventories	60	(81)	33
Margin deposits and customer margin deposits payable	(18)	(1)	4
Other current assets and deferred charges	(15)	43	7
Accounts payable	250	(14)	5
Accrued liabilities	51	(29)	(170)
Changes in current and noncurrent derivative assets and liabilities	7	(42)	36
Other, including changes in noncurrent assets and liabilities	(1)	(2)	48
Net cash provided by operating activities	3,439	2,651	2,572
FINANCING ACTIVITIES:			
Proceeds from long-term debt	3,172	5,129	595
Payments of long-term debt	(2,055)	(4,305)	(33)
Proceeds from sale of limited partner units of consolidated partnership		806	
Dividends paid	(457)	(284)	(256)
Dividends and distributions paid to noncontrolling interests	(214)	(145)	(129)
Cash of WPX Energy, Inc. at spin-off	(526)		
Payments for debt issuance costs	(50)	(71)	(7)
Premiums paid on early debt retirements	(254)	(574)	
Changes in restricted cash			40
Other net	42	17	(44)
Net cash provided (used) by financing activities	(342)	573	166
INVESTING ACTIVITIES:			
Capital expenditures(1)	(2,796)	(2,788)	(2,387)
Purchases of investments/advances to affiliates	(233)	(488)	(142)
Purchase of businesses	(41)	(1,099)	
Distribution from Gulfstream Natural Gas System, L.L.C.			148
Other net	67	79	71
Net cash used by investing activities	(3,003)	(4,296)	(2,310)
Increase (decrease) in cash and cash equivalents	94	(1,072)	428
Cash and cash equivalents at beginning of year(2)	795	1,867	1,439
Cash and cash equivalents at end of year(2)	$ 889	$ 795	$ 1,867

(1) Increases to property, plant, and equipment	$ (2,953)	$ (2,755)	$ (2,314)
Changes in related accounts payable and accrued liabilities	157	(33)	(73)
Capital expenditures	$ (2,796)	$ (2,788)	$ (2,387)

(2) Except for cash and cash equivalents at end of year 2011, includes cash from our former exploration and production business (See Note 2).

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Description of Business

Our operations are located principally in the United States and are organized into the following reporting segments: Williams Partners and Midstream Canada & Olefins. 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 include 100 percent of Transcontinental Gas Pipe Line Company, LLC (Transco), 100 percent of Northwest Pipeline GP (Northwest Pipeline), and 49 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream). WPZ s midstream operations are composed of significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, operations in Pennsylvania s Marcellus Shale region, and various equity investments in domestic 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, as well as an NGL fractionator and storage facilities near Conway, Kansas.

Our Midstream Canada & Olefins segment includes our oil sands off-gas processing plant near Fort McMurray, Alberta, our NGL/olefin fractionation facility and butylene/butane splitter facility at Redwater, Alberta, our NGL light-feed olefins cracker in Geismar, Louisiana, along with associated ethane and propane pipelines, and our refinery grade splitter in Louisiana.

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

Basis of Presentation

In May 2011, we contributed a 24.5 percent interest in Gulfstream to WPZ in exchange for aggregate consideration of $297 million of cash, 632,584 limited partner units, and an increase in the capital account of its general partner to allow us to maintain our 2 percent general partner interest. Williams Partners now holds a 49 percent interest in Gulfstream. We also own an additional 1 percent interest in Gulfstream reported in Other. Prior period segment disclosures have not been adjusted for this transaction as the impact, which was less than 2.5 percent of Williams Partners segment profit for all periods affected, was not material. Equity earnings related to this interest in Gulfstream that have not been recast for the years ended December 31, 2011, 2010, and 2009 are $12 million, $32 million, and $30 million, respectively.

Master limited partnership

At December 31, 2011, we own approximately 75 percent of the interests in WPZ, including the interests of the general partner, which are wholly owned by us, and incentive distribution rights.

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

Discontinued operations

WPX separation

On December 31, 2011, we completed the tax-free spin-off of our 100 percent interest in WPX Energy, Inc. (WPX), to our shareholders. WPX was formed in April 2011 to hold our former exploration and production business. 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.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On December 30, 2011, we entered into a Separation and Distribution Agreement with WPX which at the time was a wholly owned subsidiary, pursuant to which WPX would be legally and structurally separated from us. In addition to, and concurrently with, this agreement, we entered into certain ancillary agreements with WPX, including, (i) an Employee Matters Agreement that sets forth agreements as to certain employment, compensation, and benefits matters, (ii) a Tax Sharing Agreement that governs rights and obligations after the spin-off with respect to matters regarding U.S. Federal, state, local, and foreign income taxes and other taxes, including tax liabilities and benefits, attributes, returns, and contests, and (iii) a Transition Services Agreement under which we or certain of our subsidiaries will provide WPX with certain services for a limited time to help ensure an orderly transition following the Distribution Date.

For periods prior to the spin-off, the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our former exploration and production business as discontinued operations. At December 31, 2011, all net assets of our former exploration and production business have been removed from our consolidated balance sheet as the spin-off was complete. (See Note 2.)

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

Accounting standards issued but not yet adopted

In June 2011, the FASB issued Accounting Standards Update No. 2011-5, Comprehensive Income (Topic 220) Presentation of Comprehensive Income (ASU 2011-5). ASU 2011-5 requires presentation of net income and other comprehensive income either in a single continuous statement or in two separate, but consecutive, statements. ASU 2011-5 requires separate presentation in both net income and other comprehensive income of reclassification adjustments for items that are reclassified from other comprehensive income to net income. The new guidance does not change the items reported in other comprehensive income, nor affect how earnings per share is calculated and presented. We currently report net income in the Consolidated Statement of Operations and report other comprehensive income in the Consolidated Statement of Changes in Equity. In December 2011, The FASB issued Accounting Standards Update No. 2011-12, Comprehensive Income (Topic 220) Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU 2011-12). ASU 2011-12 defers the effective date for only the presentation requirements related to reclassifications in ASU 2011-5. During this deferral period, ASU 2011-12 states that we should continue to report reclassifications out of accumulated other comprehensive income consistent with the presentation requirements in effect before ASU 2011-05. All other requirements in ASU 2011-05 are not affected by ASU 2011-12, including the requirement to report comprehensive income either in a single continuous financial statement or in two separate but consecutive financial statements. Both standards are effective beginning the first quarter of 2012, with retrospective application to prior periods. We will apply the new guidance for both standards beginning in 2012.

Summary of Significant Accounting Policies

Principles of consolidation

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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 and long-lived assets;
- Litigation-related contingencies;
- Environmental remediation obligations;
- Realization of deferred income tax assets;
- Asset retirement obligations;
- Pension and postretirement valuation variables.

These estimates are discussed further throughout these notes.

Regulatory accounting

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

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 conditions 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. We determine the cost of certain natural gas inventories held by Transco using the last-in, first-out (LIFO) cost method. There was no LIFO inventory at December 31, 2011. LIFO inventory at December 31, 2010 was $9 million.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 9.)

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 *costs and operating 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.

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 of the Consolidated Statement of Cash Flows on a gross basis.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Realized gains and losses on derivatives that require physical delivery, as well as natural gas derivatives for NGL processing activities and which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we considered whether we act as principal in the transaction; whether we have the risks and rewards of ownership, including credit risk; and whether we have latitude in establishing prices.

Revenues

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

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

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

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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil gathering and transportation revenues and offshore production handling fees of Williams Partners 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.

Within Williams Partners, we market NGLs 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.

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

Our midstream Canada business has processing and fractionation operations where we retain certain NGLs and olefins from an upgrader s off-gas stream and we recognize revenues when the fractionated products 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.

Impairment of long-lived assets and investments

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

For assets identified to be disposed of in the future and considered held for sale, we compare the carrying value to the estimated fair value less the cost to sell to determine if recognition of an impairment is required. Until the assets are disposed of, the estimated fair value, which includes estimated cash flows from operations until the assumed date of sale, is recalculated when related events or circumstances change.

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.

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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 the average interest rate on debt.

Employee stock-based awards

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable over a three-year period from the date of grant and can be subject to accelerated vesting if certain future stock prices or specific financial performance targets are achieved. Stock options generally expire ten years after the grant.

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

Income taxes

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

Effective with the spin-off of WPX on December 31, 2011, certain state and federal tax attributes (primarily alternative minimum tax credits) will be allocated between us and WPX pursuant to the consolidated return regulations. Although the final allocation of these tax attributes cannot be determined until the consolidated tax returns for tax year 2011 are complete, an estimate of the allocated tax attributes has been recorded in 2011.

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 *accumulated other comprehensive income (loss)*.

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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Discontinued Operations

In addition to the accounting policies previously discussed, the following policies were considered significant to our former exploration and production business.

Significant estimates and assumptions included the valuation of oil and natural gas reserves, valuation of derivatives and hedge accounting correlations and probability;

Property, plant and equipment related to oil and gas exploration and production activities were accounted for under the successful efforts method. Depreciation, depletion and amortization was provided under the units-of-production method on a field basis;

Goodwill was evaluated at least annually for impairment by first comparing our management s estimate of the fair value of a reporting unit with its carrying value, including goodwill. As a result of significant declines in forward natural gas prices during the third quarter of 2010, we performed an impairment assessment of our goodwill which resulted in a $1 billion impairment (See Note 2);

Revenues for sales of natural gas were recognized when the product was sold and delivered;

Impairments of proved properties, including developed and undeveloped, were assessed using estimated future undiscounted cash flows on a field basis. Unproved properties included lease acquisition costs and costs of acquired unproved reserves. These costs were assessed for impairment as conditions warranted.

Note 2. Discontinued Operations

On December 31, 2011, we completed the tax-free spin-off of our interest in WPX to our shareholders. The spin-off was completed by means of a special stock dividend. (See Note 1.) The dividend to our shareholders on December 31, 2011, represented approximately $10.3 billion of assets, $4.8 billion of liabilities and $5.5 billion of net equity, which includes approximately $219 million of accumulated other comprehensive income (AOCI). The carrying value of AOCI is primarily related to net unrealized gains from WPX s cash flow hedges associated with energy commodity derivatives.

The following summarized results of discontinued operations reflect the results of operations of our former exploration and production business as discontinued operations. Each period presented includes the results of intercompany transactions with our continuing business, such as sales of commodities and charges for gathering, processing and transportation services. Although we expect certain of these types of transactions to continue in the future, the expected continuing cash flows are not considered significant; thus, the operations and cash flows of our former exploration and production business are considered to be eliminated from our ongoing operations. The summarized results of discontinued operations also include certain of our former Venezuela operations, whose facilities were expropriated by the Venezuelan government in May 2009, and settlement of various items pertaining to operations discontinued prior to periods covered by this report.

The December 31, 2010 summarized assets and liabilities of discontinued operations reflects our former exploration and production business. At December 31, 2011, the net assets of this former business have been eliminated from our consolidated balance sheet as the spin-off was complete.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized Results of Discontinued Operations

	Years Ended December 31, 2011	2010 (Millions)	2009
Revenues	$ 3,997	$ 4,042	$ 3,684
Income (loss) from discontinued operations before impairments, gain on deconsolidation and income taxes	$ 223	$ 350	$ 338
Impairments	(755)	(1,682)	(242)
Gain on deconsolidation			9
(Provision) benefit for income taxes	115	139	(90)
Income (loss) from discontinued operations	$ (417)	$ (1,193)	$ 15
Income (loss) from discontinued operations:			
Attributable to noncontrolling interests	$ 10	$ 8	$ (64)
Attributable to The Williams Companies, Inc.	$ (427)	$ (1,201)	$ 79

Income (loss) from discontinued operations before impairments, gain on deconsolidation and income taxes for 2011 and 2010 primarily reflect the results of operations of our discontinued exploration and production business (see Note 1), including $42 million of transaction costs related to the spin-off recognized in 2011.

Income (loss) from discontinued operations before impairments, gain on deconsolidation and income taxes for 2009 primarily reflects $420 million of income from our discontinued exploration and production business. Also reflected are $104 million of losses from our discontinued Venezuela operations and a $15 million gain related to our former coal operations.

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 a noncash 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 fall 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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Impairments for 2009 primarily reflect a $211 million impairment of our Venezuela property, plant, and equipment that was expropriated by the Venezuelan government in 2009. We are pursuing collection of claims related to that expropriation. Also included is an impairment charge of $20 million related to natural gas producing properties and acquired unproved reserves of our discontinued exploration and production business and an $11 million impairment of a cost-based investment related to our interest in a Venezuelan corporation that owns and operates oil and gas activities.

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

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

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

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 utilizes the most observable inputs of the three approaches, we note that the short trading duration, low trading volumes and lack of liquidity in the when issued market, among other factors, serve 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As a result of this evaluation, we have 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.

Summarized Assets and Liabilities of Discontinued Operations

	December 31, 2010 (Millions)
Cash and cash equivalents	$ 37
Accounts receivable - net	362
Inventories	78
Derivative assets	400
Other current assets and deferred charges	20
Total current assets of discontinued operations	897
Investments	104
Property, plant and equipment - net	8,518
Derivative assets	173
Goodwill	8
Other assets and deferred charges	25
Total noncurrent assets of discontinued operations	8,828
Total assets	$ 9,725
Accounts payable	$ 486
Accrued liabilities	263
Derivative liabilities	147
Total current liabilities of discontinued operations	896
Deferred income taxes	1,711
Derivative liabilities	142
Other liabilities and deferred income	326
Total noncurrent liabilities of discontinued operations	2,179
Total liabilities	$ 3,075

Energy Commodity Derivatives Associated with Discontinued Operations

Our former exploration and production business produced, bought, and/or sold natural gas and crude oil at different locations throughout the United States. It also entered into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in revenues or margins from fluctuations in natural gas and crude oil market prices, it entered into natural gas and crude oil futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas and crude oil. It also entered into basis swap agreements to reduce the locational price risk associated with its producing basins.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gains and Losses

The following table presents pre-tax gains and losses for our former exploration and production business energy commodity derivatives designated as cash flow hedges. The amounts previously recognized within *revenues* or *costs and operating expenses* are now presented within discontinued operations.

	Years ended December 31, 2011	2010	Classification
	(Millions)		
Net gain (loss) recognized in other comprehensive income (loss) (effective portion)	$ 413	$ 507	AOCI
Net gain (loss) reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$ 332	$ 355	Income (loss) from discontinued operations
Gain (loss) recognized in income (ineffective portion)	$	$ 9	Income (loss) from discontinued operations

The following table presents pre-tax gains and losses for energy commodity derivatives not designated as hedging instruments. The amounts previously recognized within *revenues* or *costs and operating expenses* are now presented within discontinued operations.

	Years Ended December 31, 2011	2010
	(Millions)	
Revenues	$ 30	$ 47
Costs and operating expenses		28
Net gain (loss)	$ 30	$ 19

Recurring Fair Value Measurement Disclosures Related to Assets and Liabilities of Discontinued Operations

The following table presents, by level within the fair value hierarchy, our assets and liabilities related to discontinued operations that were measured at fair value on a recurring basis.

	December 31, 2010 Level 1	Level 2	Level 3	Total
	(Millions)			
Energy derivative assets	$ 96	$ 475	$ 2	$ 573
Energy derivative liabilities	$ 78	$ 210	$ 1	$ 289

Energy derivatives included commodity based exchange-traded contracts and over-the-counter (OTC) contracts. Exchange-traded contracts included futures, swaps, and options. OTC contracts included forwards, swaps and options.

The instruments included in these Level 1 measurements consisted of energy derivatives that were exchange-traded. Exchange-traded contracts included New York Mercantile Exchange and Intercontinental Exchange contracts and were valued based on quoted prices in these active markets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The instruments included in these Level 2 measurements consisted primarily of OTC instruments. Forward, swap, and option contracts included in Level 2 were valued using an income approach including present value techniques and option pricing models. Option contracts, which hedged future sales of production from our discontinued exploration and production business, were structured as costless collars and were financially settled. They were valued using an industry standard Black-Scholes option pricing model. Significant inputs into these Level 2 valuations included commodity prices, implied volatility by location, and interest rates, and considered executed transactions or broker quotes corroborated by other market data. These broker quotes were based on observable market prices at which transactions could currently be executed. In certain instances where these inputs were not observable for all periods, relationships of observable market data and historical observations were used as a means to estimate fair value. Where observable inputs were available for substantially the full term of the asset or liability, the instrument was categorized in Level 2.

The instruments in these Level 3 measurements primarily consisted of natural gas index transactions that were used by our discontinued exploration and production business to manage physical requirements. These instruments were valued with a present value technique using inputs that may not have been readily observable or corroborated by other market data. These instruments were classified within Level 3 because these inputs had a significant impact on the measurement of fair value. As the fair value of natural gas index transactions was primarily driv