Williams Partners L.P.
Form 10-K
February 25, 2010

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-32599

Williams Partners L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**20-2485124**
(State or Other Jurisdiction of Incorporation or Organization)	*(IRS Employer Identification No.)*
One Williams Center, Tulsa, Oklahoma	**74172-0172**
(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 Units	New York Stock Exchange

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

None

(Title of Class)

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

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

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 þ No o

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 o No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) 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. þ

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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller Reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The aggregate market value of the registrant s common units held by non-affiliates based on the closing sale price of such units as reported on the New York Stock Exchange, as of the last business day of the registrant s most recently completed second quarter was approximately $740,953,508. This figure excludes common units beneficially owned by the directors and executive officers of Williams Partners GP LLC, our general partner.

The registrant had 52,777,452 common units and 203,000,000 Class C units outstanding as of February 24, 2010.

DOCUMENTS INCORPORATED BY REFERENCE

None

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DEFINITIONS

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

Barrel: One barrel of petroleum products equals 42 U.S. gallons.

Bcf/d: One billion cubic feet of natural gas per day.

bpd: Barrels per day.

British Thermal Units (Btu): When used in terms of volumes, Btu is used to refer to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.

BBtu/d: One billion Btus per day.

Dth: One dekatherm.

Mbbls/d: One thousand barrels per day.

MDth: One thousand dekatherms.

Mdt/d: One thousand dekatherms per day.

¢/MMBtu: Cents per one million Btus.

MMBtu: One million Btus.

MMBtu/d: One million Btus per day.

MMcf: One million cubic feet.

MMcf/d: One million cubic feet per day.

MMdt: One million dekatherms or approximately one trillion BTUs.

MMdt/d: One million dekatherms per day.

TBtu: One trillion BTUs.

Other definitions:

FERC: Federal Energy Regulatory Commission.

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

LNG: Liquified natural gas. Natural gas which has been liquefied at cryogenic temperatures.

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

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

Partially Owned Entities: Entities in which we do not, following the consummation of the Dropdown, own a 100% ownership interest, including principally Discovery, Gulfstream, Northwest Pipeline, and Laurel Mountain.

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Pipeline Entities: Our regulated pipeline entities, including principally Northwest Pipeline, Transco, Gulfstream, Discovery and Black Marlin Pipeline LLC.

Recompletions: After the initial completion of a well, the action and techniques of reentering the well and redoing or repairing the original completion to restore the well s productivity.

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

Workover: Operations on a completed production well to clean, repair and maintain the well for the purposes of increasing or restoring production.

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PART I

Items 1 and 2. ***Business and Properties***

Unless the context clearly indicates otherwise, references in this report to we, our, us or like terms refer to Williams Partners L.P. and its subsidiaries. Unless the context clearly indicates otherwise, references to we, our, and us include the operations of Wamsutter LLC (Wamsutter) and our Partially Owned Entities in which we own interests accounted for as equity investments that are not consolidated in our financial statements. When we refer to Wamsutter or our Partially Owned Entities by name, we are referring exclusively to their businesses and operations.

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 and other documents electronically with the U.S. Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934, as amended (the Exchange Act). You may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC s Internet website at *http://www.sec.gov*.

Our Internet website is *http://www.williamslp.com*. We make available free of charge through the Investor Relations 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 Business Conduct and Ethics and the charter of the audit committee of our general partner s board of directors are also available on our Internet website under the Investor Relations caption. We will also provide, free of charge, a copy of any of our governance documents listed above upon written request to our general partner s secretary at Williams Partners L.P., One Williams Center, Suite 4700, Tulsa, Oklahoma 74172.

GENERAL

We are a publicly-traded Delaware limited partnership formed by The Williams Companies, Inc. (Williams) in February 2005. We were formed to own, operate and acquire a diversified portfolio of complementary energy assets. Prior to the completion of the Dropdown discussed below, our focus was on the gathering, transporting, processing and treating of natural gas and the fractionation and storage of NGLs. Fractionation is the process by which a mixed stream of NGLs is separated into its constituent products, such as ethane, propane and butane. These NGLs result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels and gasoline additives, among other applications.

Our assets were owned by Williams prior to the initial public offering (IPO) of our common units in August 2005, our acquisition of Williams Four Corners LLC (Four Corners) in 2006, our acquisition of an additional 20% ownership percentage of Discovery Producer Services LLC (Discovery) in 2007 and our acquisition of ownership interests in Wamsutter in 2007. The assets acquired in February 2010 through the Dropdown discussed below were also owned by Williams. After the Dropdown, Williams indirectly owns an approximate 82% limited partnership interest in us and all of our 2% general partner interest.

Williams is an integrated energy company with 2009 revenues in excess of $8.2 billion that trades on the New York Stock Exchange under the symbol WMB. Williams operates in a number of segments of the energy industry, including natural gas exploration and production, interstate natural gas transportation and midstream services. Williams has been in the midstream natural gas and NGL industry for more than 20 years.

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

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RECENT EVENTS

The Dropdown

On February 17, 2010, we closed a transaction with our general partner, our operating company, Williams and certain subsidiaries of Williams, pursuant to which Williams contributed to us the ownership interests in the entities that make up Williams Gas Pipeline and Midstream Gas & Liquids business segments, to the extent not already owned by us, including Williams limited and general partner interests in Williams Pipeline Partners L.P. (WMZ), but excluding Williams Canadian, Venezuelan and olefin operations and 25.5% of Gulfstream Natural Gas System, L.L.C. (Gulfstream). Such entities are hereafter referred to as the Contributed Entities . This contribution was made in exchange for aggregate consideration of:

- $3.5 billion in cash, less certain expenses incurred by us relating to our acquisition of the Contributed Entities. This cash consideration was financed through the private issuance of $3.5 billion of senior unsecured notes with net proceeds of $3.466 billion.

- 203 million of our Class C limited partnership units, which are identical to our common limited partnership units except that for the distribution with respect to the first quarter of 2010 they will receive a prorated quarterly distribution since they were not outstanding during the full quarterly period. The Class C units will automatically convert into our common limited partnership units following the record date for the distribution with respect to the first quarter of 2010.

- an increase in the capital account of our general partner to allow it to maintain its 2% general partner interest.

The transactions described in the preceding paragraph are referred to as the Dropdown.

Beginning with reporting of first-quarter 2010 results, our operations will be divided into two business segments: Gas Pipeline and Midstream Gas & Liquids. All of the operations we conducted prior to the Dropdown will be reported within the Midstream Gas & Liquids segment. The Contributed Entities business activities will be included in our two business segments as follows:

- Gas Pipeline will include Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline GP (Northwest Pipeline), which own and operate a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,700 TBtu of natural gas and peak-day delivery capacity of approximately 12 MMdt of natural gas. Gas Pipeline will also hold interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5% interest in Gulfstream, which owns an approximate 745-mile pipeline with the capacity to transport approximately 1.26 million Dth per day of natural gas.

- Midstream Gas & Liquids will include the Contributed Entities natural gas gathering, processing and treating facilities located primarily in the Rocky Mountain and Gulf Coast regions of the United States and natural gas and crude oil gathering and transportation facilities in the Gulf Coast region of the United States.

WMZ Exchange Offer

We have also announced our intention to launch an exchange offer for the publicly traded common units of WMZ at a future date (the WMZ Exchange Offer). We will offer a fixed exchange ratio of 0.7584 of our common units for each WMZ common unit. The ratio is based on closing prices on the New York Stock Exchange on Friday, January 15, 2010, the business day before our intention to make the exchange offer was announced, of $23.35 for WMZ and $30.79 for us. The exact timing of the launch will be based upon the filing of necessary offering documents with the SEC and upon market conditions. If we acquire ownership of more than 75% of WMZ s outstanding common units pursuant to the WMZ Exchange Offer, we will consider causing the general partner of WMZ to (i) deregister WMZ under the Exchange Act or cause its common units to no longer be traded on the New York Stock Exchange, if these options are available, (ii) exercise its right under WMZ s limited partnership agreement to purchase all of the remaining common units or (iii) exercise any other available options.

New Credit Facility

In connection with the Dropdown, we entered into a new $1.75 billion senior unsecured revolving three-year credit facility with Transco and Northwest Pipeline, as co-borrowers with borrowing sublimits of $400 million each, and Citibank, N.A. as administrative agent, and other lenders named therein (New Credit Facility). The New Credit Facility replaced our existing $450 million senior unsecured credit agreement. At the closing of the Dropdown, we borrowed $250 million under the New Credit Facility to repay the term loan outstanding under our existing credit facility.

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FINANCIAL INFORMATION ABOUT SEGMENTS

See Part II, Item 8 Financial Statements and Supplementary Data.

NARRATIVE DESCRIPTION OF BUSINESS PRIOR TO THE DROPDOWN

At December 31, 2009, the operations of our businesses, which are located in the United States, were organized into three reporting segments: (1) Gathering and Processing West, (2) Gathering and Processing Gulf and (3) NGL Services.

The discussion below reflects the operations of our businesses as they were at December 31, 2009 and does not reflect any impact thereon of the Dropdown, which was consummated in February 2010 and is discussed under the headings The Dropdown and Narrative Description of our Business after Completion of the Dropdown.

Gathering and Processing West

Our Gathering and Processing West segment includes a 100% interest in Four Corners and ownership interests in Wamsutter, consisting of (i) 100% of the Class A limited liability company membership interests and (ii) 69% of the Class C limited liability company membership interests in Wamsutter (together, the Wamsutter Ownership Interests).

Four Corners

The Four Corners assets include an approximate 3,800-mile natural gas gathering system in the San Juan Basin in New Mexico and Colorado, three natural gas processing plants and two natural gas treating plants. We provide our customers, primarily natural gas producers in the San Juan Basin, with a full range of gathering, processing and treating services. Four Corners revenues are comprised of product sales and fee-based gathering, processing, and treating revenues. Fee-based gathering, processing and treating services accounted for approximately 75% of Four Corners total revenue less product cost and shrink replacement for the year ended December 31, 2009. The remaining 25% was derived from the sale of NGLs received as consideration for processing services. For more detail of Four Corners revenues, please read Note 17, Segment Disclosures, in our Notes to Consolidated Financial Statements in this report.

During 2009, our Four Corners gathering system gathered approximately 36% of the natural gas produced in the San Juan Basin. It connects with the five pipeline systems that transport natural gas to end markets from the basin. Approximately 40% of the supply connected to our Four Corners pipeline system in the San Juan Basin is produced from conventional formations with approximately 60% coming from coal bed formations.

Wamsutter

In 2009, we owned the Wamsutter Ownership Interests and accounted for this investment under the equity method of accounting due to the voting provisions of Wamsutter s limited liability company agreement which provided the other member of Wamsutter, Williams, significant participatory rights such that we did not control the investment. Following the Dropdown, Wamsutter LLC became our wholly owned, consolidated subsidiary.

Wamsutter owns an approximate 1,880-mile natural gas gathering system in the Washakie Basin and a natural gas processing plant in Sweetwater County, Wyoming. Wamsutter provides its customers, primarily natural gas producers in the Washakie Basin, with a broad range of gathering and processing services. Fee-based gathering, processing and other services accounted for approximately 43% of Wamsutter s total revenues less product costs for the year ended December 31, 2009. The remaining 57% was derived primarily from the sale of NGLs received by Wamsutter as consideration for processing services.

The Wamsutter system gathers and processes approximately 69% of the natural gas produced in the Washakie Basin and connects with four natural gas pipeline systems that transport natural gas to end markets from the basin.

Gathering and Processing Gulf

Our Gathering and Processing Gulf segment is comprised of our 60% interest in Discovery and the Carbonate Trend gathering pipeline.

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Discovery

We own a 60% interest in Discovery and account for this investment under the equity method of accounting due to the voting provisions of Discovery s limited liability company agreement which provide the other member of Discovery significant participatory rights such that we do not control the investment. Discovery owns an approximate 300-mile natural gas gathering and transportation pipeline system, located primarily off the coast of Louisiana in the Gulf of Mexico, a cryogenic natural gas processing plant in Larose, Louisiana and a fractionator in Paradis, Louisiana.

Carbonate Trend Pipeline

Our Carbonate Trend gathering pipeline is a sour gas gathering pipeline consisting of approximately 34 miles of pipeline that is used to gather sour gas production from the Carbonate Trend area off the coast of Alabama. For the year ended December 31, 2009, our average transportation volume was approximately 18 MMcf/d. Our Carbonate Trend pipeline is not regulated under the Natural Gas Act but is regulated under the Outer Continental Shelf Lands Act, which requires us to transport gas supplies on the Outer Continental Shelf on an open and non-discriminatory access basis.

NGL Services

Our NGL Services segment includes our three integrated NGL storage facilities and a 50% interest in an NGL fractionator near Conway, Kansas. These assets are strategically located at one of the two major NGL trading hubs in the continental United States.

Conway Storage Assets

We own and operate three integrated underground NGL storage facilities in the Conway, Kansas area with an aggregate storage capacity of approximately 20 million barrels, which we refer to as the Conway West, Conway East and Mitchell storage facilities. Each facility is comprised of a network of caverns located several hundred feet below ground, and all three facilities are connected by pipeline. The caverns hold large volumes of NGLs and other hydrocarbons, such as propylene and naphtha. We operate these assets as one coordinated facility. Three lines connect the Mitchell facility to the Conway West facility and two lines connect the Conway East facility to the Conway West Facility. These facilities have a total brine pond capacity of approximately 13 million barrels. A brine pond is an above-ground location that stores brine, or salt water, until it is pumped into the storage cavern to displace and move NGLs. These facilities generate revenues under fee-based contractual arrangements.

Our Conway storage facilities interconnect directly with three end-use interstate NGL pipelines: MAPL, NuStar and the ONEOK North System (formerly Kinder Morgan) pipeline. We also, through connections of less than a mile, indirectly interconnect to an additional end-use interstate NGL pipeline: the ONEOK pipeline. Through these pipelines and other storage facilities we can provide our customers interconnectivity to additional interstate NGL pipelines. We believe that the attributes of our storage facilities, such as the number and size of our caverns and well bores and our extensive brine system, coupled with our direct connectivity to MAPL through multiple meters allows our customers to inject, withdraw and deliver all of their products stored in our facilities more rapidly than products stored with our competitors.

Conway Fractionation Facility

The Conway fractionation facility is strategically located at the junction of the south, east and west legs of MAPL and has interconnections with the Buckeye pipeline and the ConocoPhillips Chisholm pipeline, each of which transports mixed NGLs to our facility. The Conway fractionation facility has a total design capacity of approximately 107,000 bpd and generates revenues under fee-based contractual arrangements.

We own a 50% undivided interest in the Conway fractionation facility resulting in proportionate capacity of approximately 53,500 bpd. ConocoPhillips and ONEOK own 40% and 10% undivided interests, respectively. Each joint owner markets its own capacity independently. Each owner can also contract with the other owners for additional capacity at the Conway fractionation facility, if necessary. We are the operator of the facility pursuant to an operating agreement that extends until May 2011.

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NARRATIVE DESCRIPTION OF OUR BUSINESS AFTER COMPLETION OF THE DROPDOWN

Operations of our businesses after the Dropdown continue to be located exclusively within the United States. We manage our business and analyze our results of operations on a segment basis. After the Dropdown, our operations are divided into two business segments:

Gas Pipeline this segment includes our interstate natural gas pipelines and pipeline joint venture investments. Gas Pipeline also includes our interests in WMZ, a publicly traded master limited partnership that was formed by Williams in 2007.

Midstream Gas & Liquids this segment includes our natural gas gathering, treating and processing business and is comprised of several wholly owned and partially owned subsidiaries.

Detailed discussion of each of our new business segments after the Dropdown follows.

Gas Pipeline

After the Dropdown, we own and operate a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,700 TBtu of natural gas and peak-day delivery capacity of approximately 12 MMdt of natural gas. Gas Pipeline consists of Transco and Northwest Pipeline. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5% interest in Gulfstream. Gas Pipeline also includes WMZ.

Transco

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

Pipeline system and customers

At December 31, 2009, Transco s system had a mainline delivery capacity of approximately 4.7 MMdt of natural gas per day from its production areas to its primary markets. Using its Leidy Line along with market-area storage and transportation capacity, Transco can deliver an additional 3.9 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.6 MMdt of natural gas per day. Transco s system includes 45 compressor stations, four underground storage fields, and an LNG storage facility. Compression facilities at sea level-rated capacity total approximately 1.5 million horsepower.

Transco s major natural gas transportation customers are public utilities and municipalities that provide service to residential, commercial, industrial and electric generation end users. Shippers on Transco s system include public utilities, municipalities, intrastate pipelines, direct industrial users, electrical generators, gas marketers and producers. Two of our customers accounted for approximately 10% each of Transco s total revenues in 2009. Transco s firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Transco s business. Additionally, Transco offers storage services and interruptible transportation services under short-term agreements.

Transco has natural gas storage capacity in four underground storage fields located on or near its pipeline system or market areas and operates two of these storage fields. Transco also has storage capacity in an LNG storage facility that we own and operate. The total usable gas storage capacity available to Transco and its customers in such underground storage fields and LNG storage facility and through storage service contracts is approximately 204 billion cubic feet of gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent ownership interest in Pine Needle LNG Company, LLC, an LNG storage facility with 4 billion cubic feet of storage capacity. Storage capacity permits Transco s customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Transco expansion projects

The pipeline projects listed below were completed during 2009 or are future significant pipeline projects for which Transco has customer commitments.

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Sentinel Expansion Project

The Sentinel Expansion Project is a recently completed expansion of Transco s existing natural gas transmission system from the Leidy Hub in Clinton County, Pennsylvania and from the Pleasant Valley interconnection with Cove Point LNG in Fairfax County, Virginia to various delivery points requested by the shippers under the project. The capital cost of the project is estimated to be up to approximately $229 million. Phase I was placed into service in December 2008. Phase II was placed into service in November 2009.

Mobile Bay South Expansion Project

The Mobile Bay South Expansion Project involves the addition of compression at Transco s Station 85 in Choctaw County, Alabama, to allow Transco to provide firm transportation service southbound on the Mobile Bay line from Station 85 to various delivery points. In May 2009, Transco received approval from the FERC. The capital cost of the project is estimated to be approximately $37 million. Transco plans to place the project into service by May 2010.

Mobile Bay South II Expansion Project

The Mobile Bay South II Expansion Project involves the addition of compression at Transco s Station 85 in Choctaw County, Alabama, and modifications to existing facilities at Transco s Station 83 in Mobile County, Alabama, to allow Transco to provide additional firm transportation service southbound on the Mobile Bay line from Station 85 to various delivery points. In November 2009, Transco filed an application with the FERC. The capital cost of the project is estimated to be approximately $36 million. Transco plans to place the project into service by May 2011.

85 North Expansion Project

The 85 North Expansion Project involves an expansion of Transco s existing natural gas transmission system from Station 85 in Choctaw County, Alabama, to various delivery points as far north as North Carolina. In September 2009, Transco received approval from the FERC. The capital cost of the project is estimated to be $241 million. Transco plans to place the project into service in phases, in July 2010 and May 2011.

Mid-South Expansion Project

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. Transco anticipates filing an application with the FERC in the fourth quarter of 2010. The capital cost of the project is estimated to be approximately $200 million. Transco plans to place the project into service in September 2012.

Mid-Atlantic Connector Project

The Mid-Atlantic Connector Project involves an expansion of Transco s mainline from an existing interconnection with East Tennessee Natural Gas in North Carolina to markets as far downstream as Maryland. Transco anticipates filing an application with the FERC in the first quarter of 2011. The capital cost of the project is estimated to be approximately $55 million. Transco plans to place the project into service in November 2012.

Rockaway Delivery Lateral Project

The Rockaway Delivery Lateral Project involves the construction of a three-mile offshore lateral to National Grid s distribution system in New York. Transco anticipates filing an application with the FERC in the third quarter of 2010. The capital cost of the project is estimated to be approximately $120 million. Transco plans to place the project into service in November 2013.

Operating statistics

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

	2009	2008	2007
		(In TBtu)	
Market-area deliveries:			
Long-haul transportation	624	753	839
Market-area transportation	1,093	969	875
Total market-area deliveries	1,717	1,722	1,714
Production-area transportation	184	188	190
Total system deliveries	1,901	1,910	1,904
Average Daily Transportation Volumes	5.2	5.2	5.2
Average Daily Firm Reserved Capacity	6.8	6.8	6.6

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

Northwest Pipeline

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

Northwest Pipeline is currently owned 65% by us and 35% by WMZ. Assuming the successful completion of the WMZ Exchange Offer and any follow-on cash call in which we acquire any unexchanged WMZ units, Northwest Pipeline will be our wholly owned subsidiary.

Pipeline system and customers

At December 31, 2009, Northwest Pipeline s system, having long-term firm transportation agreements including peaking service of approximately 3.7 Bcf of natural gas per day, was composed of approximately 3,900 miles of mainline and lateral transmission pipelines and 41 transmission compressor stations having a combined sea level-rated capacity of approximately 473,000 horsepower.

In 2009, Northwest Pipeline served a total of 129 transportation and storage customers. 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. The two largest customers of Northwest Pipeline in 2009 accounted for approximately 22% and 11%, respectively, of its total operating revenues. No other customer accounted for more than 10% of Northwest Pipeline s total operating revenues in 2009. 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, which have an aggregate working gas storage capacity of 13 Bcf of gas and firm delivery capability of approximately 700 MMcf of gas per day, enable Northwest Pipeline to provide storage services to its customers and to balance daily receipts and deliveries.

Northwest Pipeline expansion projects

The pipeline projects listed below were completed during 2009 or are future pipeline projects for which Northwest Pipeline has customer commitments.

Colorado Hub Connection Project

In November 2009, Northwest Pipeline placed into service the new 27-mile, 24-inch diameter lateral referred to as the Colorado Hub Project (CHC Project). The new lateral connects the Meeker/White River Hub near Meeker, Colorado to its mainline south of Rangely, Colorado, and is estimated to cost up to $60 million. The CHC Project combined the new lateral capacity with existing mainline capacity to provide approximately 363 MDth per day of firm transportation from various receipt points to delivery points on the mainline as far south as Ignacio, Colorado. In April 2009, the FERC issued a certificate approving the CHC Project, including the presumption of rolling in the costs of the project in any future rate case filed with the FERC.

Sundance Trail Expansion

In November 2009, Northwest Pipeline received approval from the FERC to construct approximately 16 miles of 30-inch loop between Northwest Pipeline s existing Green River and Muddy Creek compressor stations in Wyoming as well as an upgrade to Northwest Pipeline s existing Vernal compressor station, with service targeted to commence in November 2010. The total project is estimated to cost up to $65 million, including the cost of replacing existing compression at Vernal, which will enhance the efficiency of Northwest Pipeline s system. Northwest Pipeline executed a precedent agreement for 150 MDth per day of firm transportation service from the Greasewood and Meeker Hubs in Colorado for delivery to the Opal Hub in Wyoming. Northwest Pipeline has proposed to collect its maximum system rates and in the certificate order approving the project, the FERC granted the presumption of rolling in the costs of the project in any future rate cases.

Operating statistics

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

	2009	2008	2007
		(In TBtu)	
Total Transportation Volume	769	781	757
Average Daily Transportation Volumes	2.1	2.1	2.1
Average Daily Reserved Capacity Under Base Firm Contracts, excluding peak capacity	2.7	2.5	2.5
Average Daily Reserved Capacity Under Short-Term Firm Contracts (1)	0.5	0.7	0.8

(1) Consists primarily of additional capacity created from time to time through the installation of new receipt or delivery points or the segmentation of existing mainline capacity. Such capacity is generally marketed on a short-term firm basis.

Gulfstream

Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida. Gulfstream is owned by the following entities:

Owners of Gulfstream	**Ownership Interest**
Williams Partners Operating LLC, a subsidiary of Williams Partners L.P.	24.5%
WGP Gulfstream Pipeline Company, L.L.C., an indirect, wholly owned subsidiary of Williams	25.5%
Spectra Energy Partners OLP, LP, a Delaware master limited partnership	24.5%
Spectra Energy Southeast Pipeline Corporation, an indirect, wholly owned subsidiary of Spectra Energy Corporation	25.5%

Gulfstream expansion projects

Gulfstream placed the Phase III expansion project in service on September 1, 2008. The project extended the pipeline system into South Florida and fully subscribed the remaining 345 Mdt/d of firm capacity on the existing pipeline system on a long-term basis. The capital cost of this project was $118 million. Service under the Gulfstream Phase IV expansion project began during the fourth quarter of 2008. The project is fully subscribed on a long-term basis and is the first incremental expansion of Gulfstream s mainline capacity.

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The capital cost of this expansion was $190 million. The Phase V expansion involves the addition of compression to provide 35 Mdt/d of firm capacity by July 2011. The estimated capital cost of this expansion is approximately $54 million with our share being 24.5% of such cost incurred after completion of the Dropdown.

WMZ

WMZ was formed to own and operate natural gas transportation and storage assets. After the Dropdown, we own an approximate 45.7% limited partnership interest and a 2% general partner interest in WMZ. A subsidiary of ours, Williams Pipeline GP LLC, serves as the general partner of WMZ. WMZ owns a 35% interest in Northwest Pipeline.

In connection with the announcement of the Dropdown, we announced our intention to launch an exchange offer for the publicly held units of WMZ at a future date, subject to certain conditions. Please read Recent Events WMZ Exchange Offer above for more information.

Midstream Gas & Liquids

Our Midstream segment, 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. Midstream s primary businesses natural gas gathering, treating, and processing; NGL fractionation, storage and transportation; and oil transportation fall within the middle of the process of taking raw natural gas and crude oil from the producing fields to the consumer.

Key variables for our business will continue to be:

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

Gathering, processing and treating

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

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

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

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Our gas gathering and processing customers are generally natural gas producers who have proved and/or producing natural gas fields in the areas surrounding our infrastructure. During 2009, these operations gathered and processed gas for approximately 230 gas gathering and processing customers. Our top 7 gathering and processing customers accounted for approximately 50% of our gathering and processing revenue.

In addition to our natural gas assets, we own and operate three deepwater crude oil pipelines and own two 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 we purchase oil from producers at the receipt points of our crude oil pipelines for an index-based price and resell the oil at delivery points at the same index-based price. Our offshore floating production platform provides centralized services to deepwater producers such as compression, separation, production handling, water removal and pipeline landings. Revenue sources have historically included a combination of fixed-fee, volumetric-based fee and cost reimbursement arrangements. Fixed fees associated with the resident production at our Devils Tower facility are recognized on a units-of-production basis.

Geographically, our Midstream natural gas assets are positioned to maximize commercial and operational synergies with Williams and our other assets. For example, most of our offshore gathering and processing assets attach and process or condition natural gas supplies delivered to the Transco pipeline. Also, our gathering and processing facilities in the San Juan basin handle approximately 87% of Williams Exploration & Production segment s equity production in this basin. Our Willow Creek plant, completed in 2009, is currently processing Williams Exploration & Production segment s wellhead production in the Piceance basin. Our San Juan basin, southwest Wyoming and Willow Creek systems deliver residue gas volumes into Northwest Pipeline s interstate system in addition to third-party interstate systems.

West region gathering, processing and treating

We own and/or operate gas gathering, processing and treating assets within the western states of Wyoming, Colorado and New Mexico.

In the Rocky Mountain area, our assets include:

- Approximately 3,500 miles of gathering pipelines with a capacity of nearly one Bcf/d and over 4,000 receipt points serving the Wamsutter and southwest Wyoming areas in Wyoming;
- Opal and Echo Springs processing plants with a combined daily inlet capacity of over 1,800 MMcf/d and NGL processing capacity of nearly 100 Mbbls/d.

In the Four Corners area, our assets include:

- Approximately 3,800 miles of gathering pipelines with a capacity of nearly two Bcf/d and approximately 6,500 receipt points serving the San Juan basin in New Mexico and Colorado;
- Ignacio, Kutz and Lybrook processing plants with a combined daily inlet capacity of 765 MMcf/d and NGL processing capacity of approximately 40 Mbbls/d. The Ignacio plant also has the capacity to produce slightly more than one Mbbls/d of LNG;
- Milagro and Esperanza natural gas treating plants, which remove carbon dioxide but do not extract NGLs, with a combined daily inlet capacity of 750 MMcf/d. At our Milagro facility, we also use gas-driven turbines to produce approximately 60 mega-watts per day of electricity which we primarily sell into the local electrical grid.

In the Piceance basin in Colorado, our infrastructure includes:

- The Willow Creek processing plant, a 450 MMcf/d cryogenic natural gas processing plant in western Colorado s Piceance basin, is designed to recover 30 Mbbls/d of NGLs. In the third quarter of 2009, construction was finished and the plant began operations. The plant is currently operating at its designed inlet capacity. In the current processing arrangement with Williams Exploration & Production segment, Midstream receives a volumetric-based processing fee and a percent of the NGLs extracted.

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

PGX pipeline delivering NGLs previously transported by truck from Williams Exploration & Production segment s existing Parachute area processing plants to a major NGL transportation pipeline system.

West region expansion projects

Our major capital and expansion projects include additional capacity at our Echo Springs facility and related gathering system expansions in the Wamsutter basin.

We expect to significantly increase the processing and NGL production capacities at our Echo Springs cryogenic natural gas processing plant in Wyoming. The addition of a fourth cryogenic processing train will add approximately 350 MMcf/d of processing capacity and 30 Mbbls/d of NGL production capacity, nearly doubling Echo Spring s capacities in both cases. We began construction on the fourth train at Echo Springs during the second half of 2009 and expect to bring the additional capacity online during late 2010.

Gulf region gathering, processing and treating

We own and/or operate gas gathering and processing assets and crude oil pipelines primarily within the onshore and offshore shelf and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi and Alabama. We own:

Over 700 miles of onshore and offshore natural gas gathering pipelines with a combined capacity of approximately 3.5 Bcf/d, including:

The 115-mile deepwater Seahawk gas pipeline in the western Gulf of Mexico, flowing into our Markham processing plant and serving the Boomvang and Nansen field areas;

The 139-mile Canyon Chief gas pipeline, now including the 37-mile Blind Faith extension added in the fourth quarter of 2008, in the eastern Gulf of Mexico, flowing into our Mobile Bay processing plant and serving the Devils Tower, Triton, Goldfinger, Bass Lite and Blind Faith fields;

Mobile Bay and Markham processing plants with a combined daily inlet capacity of nearly 1,000 MMcf/d and NGL handling capacity of 50 Mbbls/d;

Canyon Station production platform, which brings natural gas to specifications allowable by major interstate pipelines but does not extract NGLs, with a daily inlet capacity of 500 MMcf/d;

Three deepwater crude oil pipelines with a combined length of 300 miles and capacity of 325 Mbbls/d including:

BANJO pipeline running parallel to the Seahawk gas pipeline delivering production from two producer-owned spar-type floating production systems; and delivering production to our shallow-water platform at Galveston Area Block A244 (GA-A244) and then onshore through ExxonMobil s Hoover Offshore Oil Pipeline System (HOOPS);

Alpine pipeline in the central Gulf of Mexico, serving the Gunnison field, and delivering production to GA-A244 and then onshore through HOOPS under a joint tariff agreement;

Mountaineer oil pipeline which connects to similar production sources as our Canyon Chief pipeline and, now including the new Blind Faith extension, ultimately delivering production to ChevronTexaco s Empire Terminal in Plaquemines Parish, Louisiana;

Devils Tower production platform located in Mississippi Canyon Block 773, approximately 150 miles south-southwest of Mobile, Alabama and serving production from the Devils Tower, Triton, Goldfinger and Bass Lite fields. Located in 5,610 feet of water, it is one of the world s deepest dry tree spars. The platform, which is operated by ENI Petroleum on our behalf, is capable of handling 210 MMcf/d of natural gas and 60

Mbbls/d of oil.

Gulf region expansion projects

Our current major expansion project in the Gulf region is our Perdido Norte project located in the western deepwater of the Gulf of Mexico. The investment expands our existing infrastructure and includes a total of 184 miles of oil and gas pipeline and a 200 MMcf/d expansion of our onshore Markham gas processing facility. We expect the project to begin start-up operations in the first quarter of 2010.

NGL marketing services

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

Other

We own interests in and/or operate NGL fractionation and storage assets. These assets include two partially owned NGL fractionation facilities: one near Conway, Kansas and the other in Baton Rouge, Louisiana that have a combined capacity in excess of 167 Mbbls/d. We also own approximately 20 million barrels of NGL storage capacity in central Kansas near Conway.

We own a 60% 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.

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

In June 2009, we completed the formation of a new joint venture, Laurel Mountain Midstream LLC (Laurel Mountain), in the Marcellus Shale located in southwest Pennsylvania. Our partner in the venture contributed its existing Appalachian basin gathering system, which has an average throughput of approximately 100 MMcf/d. In exchange for a 51% interest, we contributed $100 million and issued a $26 million note payable. In 2010, we expect to significantly increase our investment in our Laurel Mountain joint venture through new gathering system infrastructure construction.

In conjunction with a long-term agreement with a major producer, we will construct a 28-mile natural gas gathering pipeline in the Marcellus Shale region that will deliver to the Transco pipeline. Construction is expected to begin on the 20-inch pipeline in the latter part of 2010, and it is expected to be placed into service during 2011. We will operate the pipeline, which represents our second significant midstream expansion in the Marcellus Shale.

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Operating statistics

The following table summarizes our significant operating statistics for Midstream:

	2009	**2008**	**2007**
Volumes: (1)			
Gathering (TBtu)	1,068	1,013	1,045
Plant inlet natural gas (TBtu)	1,342	1,311	1,275
NGL production (Mbbls/d) (2)	164	154	163
NGL equity sales (Mbbls/d) (2)	80	80	92
Crude oil gathering (Mbbls/d) (2)	109	70	80

(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.

REGULATORY MATTERS

Gas Pipeline

Gas Pipeline s interstate transmission and storage activities are subject to FERC regulation under the Natural Gas Act of 1938 (NGA) and under the Natural Gas Policy Act of 1978, and, as such, its rates and charges for the transportation of natural gas in interstate commerce, its accounting, and the extension, enlargement or abandonment of its jurisdictional facilities, among other things, are subject to regulation. Each gas pipeline company holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities and properties for which certificates are required under the NGA. 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;

Volume throughput assumptions.

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

Midstream Gas & Liquids

For our Midstream segment, onshore gathering is subject to regulation by states in which we operate and offshore gathering is subject to the Outer Continental Shelf Lands Act (OCSLA). Of the states where Midstream gathers gas, currently only Texas actively regulates gathering activities. Texas regulates gathering primarily through complaint mechanisms under which the state commission may resolve disputes involving an individual gathering arrangement. Although 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 gathering facilities offshore are subject to the OCSLA, which provides in part that outer continental shelf pipelines must provide open and nondiscriminatory access to both owner and nonowner shippers.

Midstream also owns interests in and operates two offshore transmission pipelines that are regulated by the FERC because they are deemed to transport gas in interstate commerce. Black Marlin Pipeline Company provides transportation service for offshore Texas production in the High Island area and redelivers that gas to intrastate pipeline interconnects near Texas City. Discovery provides transportation service for offshore Louisiana production from the South Timbalier, Grand Isle, Ewing Bank and Green Canyon (deepwater) areas to an onshore processing facility and downstream interconnect points with major interstate pipelines. FERC regulation requires all terms and conditions of service, including the rates charged, to be filed with and approved by the FERC before any changes can go into effect. In 2007, Black Marlin filed and settled a major rate change application before the FERC, resulting in increased rates for service. In November 2007, Discovery filed a settlement in lieu of a rate change filing, which the FERC approved effective January 1, 2008, for all parties, except one protestor, Exxon Mobil Gas and Power Marketing Company. Among other things, the settlement increases Discovery s rates for service, although most volumes flowing before the settlement became effective are not affected by the rate change due to life of lease rates and commitments.

Safety and Maintenance

Each gas pipeline company is subject to the Natural Gas Pipeline Safety Act of 1968, as amended, and the Pipeline Safety Improvement Act of 2002 (PSIA), which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. The Natural Gas Pipeline Safety Act regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines and some gathering lines in certain high-consequence areas.

Certain of our natural gas pipelines are subject to regulation by, among others, the United States Department of Transportation (DOT) under the Accountable Pipeline and Safety Partnership Act of 1996 (often referred to as the Hazardous Liquid Pipeline Safety Act) and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management. These statutes require access to and copying of records and the filing of certain reports and carry potential fines and penalties for violations.

Gas Pipeline Integrity Regulations

The DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) rules implementing the PSIA require pipeline operators to implement integrity management programs, including more frequent inspections and other safeguards in areas where the potential consequences of pipeline accidents pose the greatest risk to people and property. In accordance with the final rule, Transco and Northwest Pipeline developed Integrity Management Plans, identified high-consequence areas, completed baseline assessment plans, and are on schedule to complete the required assessments within specified timeframes. Currently, Transco and Northwest Pipeline estimate that the cost to perform required assessments and remediation will be primarily capital and range between $150 million and $220 million and between $65 million and $85 million, respectively, over the remaining assessment period of 2010 through 2012.

Management considers the costs incurred by Transco and Northwest to comply with the PHMSA rule to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through their respective rates.

Midstream

Discovery s gas pipeline system is subject to the Natural Gas Pipeline Safety Act of 1968 and the Pipeline Safety Improvement Act of 2002. Discovery currently anticipates incurring costs of approximately $0.3 million in 2010 to implement integrity management program testing along certain segments of Discovery s 16, 20 and 30-inch diameter natural gas pipelines and its 10, 14 and 18-inch diameter NGL pipelines. This does not include the costs, if any, of repair, remediation, or any preventative or mitigating actions that may be deemed necessary as a result of the testing program.

States are largely preempted by federal law from regulating pipeline safety but may, in certain cases, assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we or the entities in which we own an interest operate.

We are also subject to a number of federal and state laws and regulations such as the federal Occupational Safety and Health Act, referred to as OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers and the general public, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the United States Environmental Protection Agency (EPA) community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and some of the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations, with a few exemptions, apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we remain in material compliance with the OSHA and similar state and local regulations.

ENVIRONMENTAL REGULATION

We are subject to extensive and complex federal, state and local laws and regulations relating to the protection of the environment. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, operate, and upgrade equipment and facilities. While these laws and regulations carry significant costs, they do not affect competitiveness because our competitors are similarly affected. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the acquisition of permits to conduct regulated activities;
- restricting the manner in which materials can be released into the environment;
- imposing investigatory and remedial obligations to monitor or mitigate emissions or releases from former or current operations;
- imposing significant reporting requirements;
- assessing administrative, civil and criminal penalties for failure to comply with applicable legal requirements;
- in certain instances, enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to applicable laws and regulations; and
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species.

Environmental laws and regulations affecting us include, but are not limited to:

- Resource Conservation and Recovery Act (RCRA) and analogous state laws, which impose stringent requirements for the management of solid wastes, including hazardous wastes, pursuant to a comprehensive regulatory regime;
- 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;
- Clean Air Act (CAA) and analogous state laws, which impose obligations related to air emissions;
- Clean Water Act (CWA) and analogous state laws, which regulate discharge of wastewaters from our facilities to state and federal waters;
- the National Environmental Policy Act (NEPA), which requires federal agencies to assess and consider the environmental impacts of major federal projects (which may include situations where federal money, lands, or

permitting are involved) when making decisions;

the Endangered Species Act (ESA), which requires the evaluation of potential impact on endangered or threatened species and may restrict activities that adversely affect such species;

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the Rivers and Harbors Act which, among other things, requires permits for the installation of structures and other work in navigable waters of the United States; and

the Toxic Substances Control Act (TSCA), which provides the EPA with authority to require reporting, record-keeping and testing requirements, and restrictions relating to chemical substances and/or mixtures.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts currently anticipated.

We have ongoing programs designed to keep our operations in compliance with existing environmental laws and regulations and to monitor changes in applicable regulations. The following is a discussion of some of the environmental laws and regulations that are applicable to natural gas gathering, processing, transportation and storage activities and that may have a material impact on our businesses.

Waste Management

Our operations generate hazardous and non-hazardous solid wastes that may be subject to laws designed to track and control waste disposal, including RCRA, TSCA and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and non-hazardous solid wastes. Hazardous waste laws may also require corrective action, including the investigation and remediation of certain units, at a facility where such waste may have been released or disposed. For instance, CERCLA and comparable state laws impose liability, often without regard to fault or the legality of the original conduct, on certain classes of persons that may or may not have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site, as well as successors in interest. Despite the petroleum exclusion of CERCLA Section 101(14) that currently includes natural gas, our businesses may nonetheless handle other hazardous substances within the meaning of CERCLA or similar state statutes, in the course of ordinary operations and, as a result, we may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

From time to time, the EPA considers the adoption of stricter disposal standards for wastes currently designated as non-hazardous. However, it is possible that these wastes, which could include wastes currently generated during operations, will in the future be designated as hazardous wastes and, therefore, become subject to more rigorous and costly disposal requirements than non-hazardous wastes. Any such changes in the laws and regulations could have a material adverse effect on maintenance capital expenditures and operating expenses.

Site Remediation

CERCLA and comparable state laws may impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owner or operator of a site where a hazardous substance was released into the environment, and companies that disposed or arranged for the disposal of hazardous substances found at the site. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that were released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA, and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs that they incur. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

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We currently own or lease properties that for many years have been used for the transportation, compression, and storage of natural gas. Although they typically used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such substances have been taken for recycling or disposal. In addition, some of these properties may have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under their control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, our businesses could be required to (i) remove previously disposed wastes, including waste disposed of by prior owners or operators; (ii) remediate contaminated property, including groundwater contamination, whether from prior owners or operators or other historic activities or spills; or (iii) perform remedial closure operations to prevent future contamination.

Air Emissions

We are subject to increasingly stringent air regulations, and threshold limits and applicable control technologies written into the regulations regularly change over time, keeping standards dynamic. The CAA, as amended, and comparable state laws regulate emissions of air pollutants from various industrial sources, including compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require (i) pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase of existing air emissions; (ii) application for and strict compliance with air permits containing various emissions and operational limitations; or (iii) the utilization of specific emission control technologies to limit emissions. Failure to comply with these requirements could result in the assessment of monetary penalties and the pursuit of potentially criminal enforcement actions, the issuance of injunctions, and the further imposition of conditions or restrictions on permitted operations.

We may incur expenditures in the future for air pollution control equipment in connection with obtaining or maintaining operating permits and approvals for air emissions. For instance, our businesses may be required to supplement or modify air emission control equipment and strategies due to changes in state implementation plans for controlling air emissions in regional non-attainment areas, or stricter regulatory requirements for sources of hazardous air pollutants. We believe that any such future requirements imposed on our businesses will not have a material adverse effect on their operations.

Water Discharges

Laws and regulations that protect surface and groundwater, including the CWA and analogous state laws, impose restrictions and often strict controls with respect to discharges, including stormwater runoff and spills and leaks of oil and other substances associated with our operations, into certain surface and groundwater. The discharge of most substances into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. These controls, including permits associated thereunder, often require monitoring and reporting and may impose substantial potential civil and criminal penalties for noncompliance. We believe that compliance with existing permits and foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

Activities on Federal Lands

Our activities conducted on federal lands may be subject to review and assessment under current permits, federal land management directives and/or provisions of NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major federal agency actions having the potential to significantly impact the environment. In the course of such evaluations, agencies prepare environmental assessments, or more detailed environmental impact statements which assess the potential direct, indirect and cumulative impacts of a proposed project and may be made available for public review and comment. Our businesses current activities, as well as any proposed plans for future activities, on federal lands are subject to the requirements of NEPA.

Endangered Species

The ESA restricts activities that may affect threatened and endangered species or their habitats. Some facilities operated by Transco and Northwest are located in areas inhabited by threatened or endangered species. If the activities of any of our businesses are deemed to adversely affect endangered species or their habitats, we could incur additional costs or become subject to operating restrictions or bans in the affected area. Civil and criminal penalties can be imposed against any person violating the ESA.

Hazardous Materials Transportation Requirements

The DOT regulations affecting pipeline safety require pipeline operators to implement measures designed to reduce the environmental impact of discharge from onshore pipelines. These regulations require operators to maintain comprehensive spill response plans, including extensive spill response training for pipeline personnel. In addition, the DOT regulations contain detailed specifications for pipeline operation and maintenance. Please read Safety and Maintenance.

Kansas Department of Health and Environment Obligations

We currently own and operate underground storage caverns near Conway, Kansas. These storage caverns are used to store NGLs and other liquid hydrocarbons and are subject to strict environmental regulation by the KDHE. The current revision of the Underground Hydrocarbon and Natural Gas Storage regulations became effective in 2003 and regulates the storage of liquefied petroleum gas and other hydrocarbons in bedded salt for the purpose of protecting public health and safety, property and the environment. The revision also regulates the construction, operation and closure of brine ponds associated with our storage caverns. These regulations specify several compliance deadlines including the due date for final permit submittals, which was met by April 1, 2006, and the April 1, 2010 deadline for completion of mechanical integrity and casing testing requirements, which we believe our facilities will meet. Failure to comply with the Underground Hydrocarbon and Natural Gas Storage program may lead to the assessment of administrative, civil or criminal penalties.

We are in the process of modifying our Conway storage facilities, including the caverns and brine ponds, and we believe that our storage operations will be in compliance with the Underground Hydrocarbon Storage (UHS) program regulations by the applicable compliance dates. In 2003, we began to complete workovers on approximately 30 to 35 salt caverns per year and install, on average, a double liner on one to two brine ponds per year. We expect, on average, to complete workovers on each of our caverns every five to ten years and install double liners on each of our brine ponds every 18 years.

Additionally, we are currently undergoing remedial activities pursuant to KDHE Consent Orders issued in the early 1990s. The Consent Orders were issued after elevated concentrations of chlorides were discovered in various on-site and off-site shallow groundwater resources at each of our Conway storage facilities. With KDHE approval, we have installed and are operating containment and monitoring systems to contain the migration of the chloride plume at all three UHS facilities. However, investigation and delineation of chloride impacts is ongoing at Conway Underground East and Conway West as specified in their respective consent orders. One of these facilities is located near the Groundwater Management District No. 2 s jurisdictional boundary of the Equus Beds aquifer. At the Conway West facility, remediation of residual hydrocarbon derivatives from a historic pipeline release is included in the consent order required activities.

Although not mandated by any consent order, we are currently cooperating with the KDHE and other area operators in an investigation of NGLs observed in the subsurface at the Conway Underground East facility. In addition, we have also recently detected NGLs in groundwater monitoring wells adjacent to two abandoned storage caverns at the Conway West facility. Although the complete extent of the contamination appears to be limited and appears to have been arrested, we are continuing to work to delineate further the scope of the contamination. To date, the KDHE has not undertaken any enforcement action related to the NGL releases around the abandoned storage caverns.

We are continuing to monitor and evaluate our assets to prevent future releases. While we maintain an extensive inspection and audit program designed, as appropriate, to prevent and to detect and address such releases promptly, there can be no assurance that future environmental releases from our assets will not have a material effect on us.

For more information about environmental compliance and other environmental issues, please read Environmental under Management s Discussion and Analysis of Financial Condition and Results of Operations and Note 16, Commitments and Contingencies, in our Notes to Consolidated Financial Statements in this report.

COMPETITION AFTER COMPLETION OF THE DROPDOWN

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

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

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

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

Midstream Gas & Liquids. In our Midstream segment, we face regional competition with varying competitive factors in each basin. Our gathering and processing business competes with other midstream companies, interstate and intrastate pipelines, producers and independent gatherers and processors. We primarily compete with five to ten companies across all basins in which we provide services. Numerous factors impact any given customer s choice of a gathering or processing services provider, including rate, location, term, timeliness of services to be provided, pressure obligations and contract structure.

Employees

We do not have any employees. We are managed and operated by the directors and officers of our general partner. After the Dropdown, our general partner or its affiliates employed approximately 2,798 full-time employees, including 1,775 and 1,023 related to the operations of Gas Pipeline s and Midstream s businesses, respectively. Additionally, our general partner and its affiliates provide general and administrative services to us. For further information, please read Directors, Executive Officers and Corporate Governance and Certain Relationships and Related Transactions, and Director Independence Reimbursement of Expenses of our General Partner.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

We have no revenue or segment profit/loss attributable to international activities both prior to and after the Dropdown.

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

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

Certain matters discussed in this report include forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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.

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

- amounts and nature of future capital expenditures;
- expansion and growth of our business and operations;
- financial condition and liquidity;

business strategy;

cash flow from operations or results of operations;

the levels of cash distributions to unitholders;

seasonality of certain business segments; and

natural gas and NGL 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. Limited partner units are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider the risk factors discussed below in addition to the other information in this annual report. If any of the following risks were actually to occur, our business, results of operations and financial condition could be materially adversely affected. Many of the factors that could adversely affect our business, results of operations and financial condition are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

whether we have sufficient cash from operations to enable us to maintain current levels of cash distributions or to pay the minimum quarterly distribution following establishment of cash reserves and payment of fees and expenses, including payments to our general partner;

availability of supplies (including the uncertainties inherent in assessing and estimating future natural gas reserves), market demand, volatility of prices, and the availability and cost of capital;

inflation, interest rates and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);

the strength and financial resources of our competitors;

development of alternative energy sources;

the impact of operational and development hazards;

costs of, changes in, or the results of laws, government regulations (including proposed climate change legislation), 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 risks of our customers;

risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;

risks associated with future weather conditions;

acts of terrorism; and

additional risks described in our filings with the SEC.

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

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

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

We may not have sufficient cash from operations to enable us to maintain current levels of cash distributions or to pay the minimum quarterly distribution following establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

We may not have sufficient available cash from operating surplus each quarter to maintain current levels of cash distributions or to pay the minimum quarterly distribution. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the prices we obtain for our services;
- the prices of, level of production of, and demand for natural gas and NGLs and our NGL margins;
- the volumes of natural gas we gather, transport, process and treat and the volumes of NGLs we fractionate and store;
- the level of our operating costs, including payments to our general partner; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, such as:

- the level of capital expenditures we make;
- the restrictions contained in Williams indentures, our indentures and credit facility and our debt service requirements;
- the cost of acquisitions, if any;
- fluctuations in our working capital needs;
- our ability to borrow for working capital or other purposes;
- the amount, if any, of cash reserves established by our general partner; and
- the amount of cash that the Partially Owned Entities and our subsidiaries distribute to us.

Unitholders should be aware that the amount of cash we have available for distribution depends primarily on our cash flow, including cash reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses, and we may not make cash distributions during periods when we record net income.

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

A principal focus of our strategy is to continue to grow by expanding our business. Our future growth will depend upon our ability to successfully identify, finance, acquire, integrate and operate projects and businesses. Failure to achieve any of these factors would adversely affect our ability to achieve anticipated growth in the level of cash flows or realize anticipated benefits.

We may acquire new facilities or expand our existing facilities to capture anticipated future growth in natural gas production that does not ultimately materialize. As a result, our new or expanded facilities may not achieve profitability. In addition, the process of integrating newly acquired or constructed assets into our operations may result in unforeseen operating difficulties, may absorb significant management attention and may require financial resources that would otherwise be available for the ongoing development and expansion of our existing operations. Future acquisitions or construction projects may require substantial new capital and could result in the incurrence of indebtedness, additional liabilities and excessive costs that could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to unitholders. If we issue additional common units in connection with future acquisitions, unitholders interest in us will be diluted and distributions to unitholders may be reduced. Further, any limitations on our access to capital, including limitations caused by illiquidity in the capital markets, may impair our ability to complete future acquisitions and construction projects on favorable terms, if at all.

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

Our revenues, operating results, future rate of growth and the value of certain segments of our businesses depend primarily upon the prices of NGLs, natural gas, 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 and financial condition and our ability to make cash distributions to unitholders.

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

- worldwide and domestic supplies of and demand for natural gas, NGLs, petroleum, and related commodities;
- turmoil in the Middle East and other producing regions;
- the activities of the Organization of Petroleum Exporting Countries;
- terrorist attacks on production or transportation assets;
- weather conditions;
- the level of consumer demand;
- the price and availability of other types of fuels;
- the availability of pipeline capacity;
- supply disruptions, including plant outages and transportation disruptions;

the price and level of foreign imports;

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domestic and foreign governmental regulations and taxes;

volatility in the natural gas markets;

the overall economic environment;

the credit of participants in the markets where products are bought and sold; and

the adoption of regulations or legislation relating to climate change.

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

Our portfolio of derivative and other energy contracts may consist of wholesale contracts to buy and sell commodities, including contracts for natural gas, NGLs 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.

Any decrease in NGL prices or a change in NGL prices relative to the price of natural gas could affect our processing, fractionation and storage businesses.

The relationship between natural gas prices and NGL prices affects our profitability. When natural gas prices are low relative to NGL prices, it is more profitable for us and our customers to process natural gas. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas both because of the higher value of natural gas and because of the increased cost of separating the mixed NGLs from the natural gas. Higher natural gas prices relative to NGL prices may also make it uneconomical to recover ethane, which may further negatively impact sales volumes and margins. Finally, higher natural gas prices relative to NGL prices could also reduce volumes of gas processed generally, reducing the volumes of mixed NGLs available for fractionation.

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

The development of the additional natural gas reserves that are essential for our gas transportation and midstream businesses to thrive requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to our pipeline systems. Low prices for natural gas, regulatory limitations, 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 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 our pipeline and cash flows associated with the 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, or if environmental regulators restrict new natural gas drilling, the overall volume of natural gas transported and stored on our system would decline, which could have a material adverse effect on our business, financial condition and results of operations, and our ability to make cash distributions to unitholders. In addition, new LNG import facilities built near our markets could result in less demand for our gathering and transportation facilities.

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

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

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

Our use of hedging arrangements through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under 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; and
- the counterparties to our hedging arrangements fail to honor their financial commitments.

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

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

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

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

The failure of counterparties to perform their contractual obligations could adversely affect our operating results, financial condition and cash available to make distributions.

Despite performing credit analysis prior to extending credit, we are exposed to the credit risk of our contractual counterparties in the ordinary course of business even though we monitor these situations and attempt to take appropriate measures to protect ourselves. In addition to credit risk, counterparties to our commercial agreements, such as product sales, gathering, treating, storage, transportation, processing and fractionation agreements, may fail to perform their other contractual obligations. A failure of counterparties to perform their contractual obligations, including Williams, could cause us to write down or write off doubtful accounts, which could materially adversely affect our operating results, and financial condition and our ability to make cash distributions to unitholders.

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 and cash available to pay distributions 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 facilities were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to pipelines or facilities, reduced operating pressures, lack of capacity, increased credit requirements or rates charged by such pipelines or facilities or other causes, we and our customers would have reduced capacity to transport, store or deliver natural gas or NGL products to end use markets or to receive deliveries of mixed NGLs, thereby reducing our revenues. Further, although there are laws and regulations designed to encourage competition in wholesale market transactions, some companies may fail to provide fair and equal access to their transportation systems or may not provide sufficient transportation capacity for other market participants.

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, and financial condition and our ability to make cash distributions to unitholders.

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

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

As a publicly traded partnership, these developments could significantly impair our ability to make acquisitions or finance growth projects. We distribute all of our available cash to our unitholders on a quarterly basis. We typically rely upon external financing sources, including the issuance of debt and equity securities and bank borrowings, to fund acquisitions or expansion capital

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expenditures. Any limitations on our access to external capital, including limitations caused by illiquidity or volatility in the capital markets, may impair our ability to complete future acquisitions and construction projects on favorable terms, if at all. As a result, we may be at a competitive disadvantage as compared to businesses that reinvest all of their available cash to expand ongoing operations, particularly under adverse economic conditions.

Adverse economic conditions could negatively affect our results of operations.

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

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

Our total outstanding long-term debt as of December 31, 2009, was $1.0 billion, and as of February 18, 2010, after consummation of the dropdown was $6.5 billion.

Our debt service obligations and restrictive covenants in our New Credit Facility and the indentures governing our senior unsecured notes could have important consequences. For example, they could:

- make it more difficult for us to satisfy our obligations with respect our senior unsecured notes and our other indebtedness, which could in turn result in an event of default on such other indebtedness or our outstanding notes;

- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general partnership purposes or other purposes;

- adversely affect our ability to pay cash distributions to unitholders;

- diminish our ability to withstand a continued or future downturn in our business or the economy generally;

- require us to dedicate a substantial portion of our cash flow from operations to debt service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes;

- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and

- place us at a competitive disadvantage compared to our competitors that have proportionately less debt.

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, 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.

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

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Our debt agreements and Williams public indentures contain financial and operating restrictions that may limit our access to credit and affect our ability to operate our business. In addition, our ability to obtain credit in the future will be affected by Williams credit ratings.

Our public indentures contain various covenants that, among other things, limit our ability to grant certain liens to support indebtedness, merge, or sell substantially all of our assets. In addition, our New Credit Facility contains certain financial covenants and restrictions on our ability and our subsidiaries ability to incur indebtedness, to consolidate or allow any material change in the nature of our business, enter into certain affiliate transactions and make certain distributions during an event of default. 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.

Williams public indentures contain covenants that restrict Williams and our ability to incur liens to support indebtedness. 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. Williams ability to comply with the covenants contained in its debt instruments may be affected by events beyond our and Williams control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, Williams ability to comply with these covenants may be negatively impacted.

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 our public indentures or other material indebtedness could cause a cross-default or cross-acceleration of our New Credit Facility. 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 our New Credit Facility cross-defaults, 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 Financial Condition and Liquidity.

Substantially all of Williams operations are conducted through its subsidiaries. Williams cash flows are substantially derived from loans, dividends and distributions paid to it by its subsidiaries. Williams cash flows are typically utilized to service debt and pay dividends on the common stock of Williams, with the balance, if any, reinvested in its subsidiaries as loans or contributions to capital. Due to our relationship with Williams, our ability to obtain credit will be affected by Williams credit ratings. If Williams were to experience a deterioration in its credit standing or financial condition, our access to credit and our ratings could be adversely affected. Any future downgrading of a Williams credit rating would likely also result in a downgrading of our credit rating. A downgrading of a Williams credit rating could limit our ability to obtain financing in the future upon favorable terms, if at all.

Our subsidiaries are not prohibited from incurring indebtedness by their organizational documents, which may affect our ability to make distributions to unitholders.

Our subsidiaries are not prohibited by the terms of their respective organizational documents from incurring indebtedness. If they were to incur significant amounts of indebtedness, such occurrence may inhibit their ability to make distributions to us. An inability by our subsidiaries to make distributions to us would materially and adversely affect our ability to make distributions to unitholders because we expect distributions we receive from our subsidiaries to represent a significant portion of the cash available to make cash distributions to unitholders.

A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and maintaining credit ratings is under the control of independent third parties.

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

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

Credit rating agencies perform independent analysis when assigning credit ratings. 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. Our current credit ratings after the Dropdown from Moody s is Baa3, from S&P is BBB-, and from Fitch is BBB-. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the ratings agencies and no assurance can be given that we will maintain our current credit ratings.

We are subject to risks associated with climate change.

There is a growing belief that emissions of greenhouse gases may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of greenhouse gases 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.

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

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

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.

We depend on certain key customers and producers for a significant portion of our revenues and supply of natural gas and NGLs. If we lost any of these key customers or producers or contracted volumes, our revenues and cash available to pay distributions could decline.

We rely on a limited number of customers for a significant portion of our revenues. Although some of these customers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts 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, results of operations, financial condition and our ability to make cash distributions to unitholders, unless we are able to acquire comparable volumes from other sources.

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

Because we do not control the Partially Owned Entities except Northwest Pipeline, we may have limited flexibility to control the operation of or cash distributions received from these assets. Any future disagreements with the other co-owners of these assets could

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adversely affect our ability to respond to changing economic or industry conditions, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

The Partially Owned Entities may reduce their cash distributions to us in some situations.

The Partially Owned Entities organizational documents require distribution of their available cash to their members on a quarterly basis. In each case, available cash is reduced, in part, by reserves appropriate for operating their respective businesses.

Significant prolonged changes in natural gas prices could affect supply and demand, cause a reduction in or termination of the long-term transportation and storage contracts or throughput on the Pipeline Entities systems, and adversely affect our cash available to make distributions.

Higher natural gas prices over the long term could result in a decline in the demand for natural gas and, therefore, in the Pipeline Entities long-term transportation and storage contracts or throughput on their respective 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 their systems. As a result, significant prolonged changes in natural gas prices could have a material adverse effect on our Pipeline Entities business, financial condition, results of operations and cash flows, and on our ability to make cash distributions to unitholders.

The Pipeline Entities natural gas sales, transportation and storage operations are subject to regulation by 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 Pipeline Entities natural gas sales, transmission and storage operations are subject to federal, state and local regulatory authorities. Specifically, their interstate pipeline transportation and storage service is subject to regulation by 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 Pipeline Entities may offer to their customers;
- certification and construction of new facilities;
- acquisition, extension, disposition or abandonment of facilities;
- accounts and records;
- depreciation and amortization policies;
- relationships with affiliated companies who are involved in marketing functions of the natural gas business; and
- market manipulation in connection with interstate sales, purchases or transportation of natural gas.

Under the Natural Gas Act (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.

The FERC Standards of Conduct govern the relationship between natural gas transmission providers and their marketing function employees as defined by the rule. The standards of conduct are intended to prevent natural gas transmission providers from preferentially benefiting gas marketing functions by requiring the employees of a transmission provider that perform transmission functions to function independently from marketing function employees and by restricting the information that transmission providers may provide to gas marketing employees. The inefficiencies created by the restrictions on the sharing of employees and information may increase our costs, and the restriction on the sharing of information may have an adverse impact on our senior management s ability to effectively obtain important information about our business.

Unlike other 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 that it assesses, referred to as an IT feeder charge, is charged only when the facilities are used and typically is paid by producers or marketers. This means that Transco recovers the costs included in the IT feeder charge only if its facilities are used, and because it 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. Longer term, this rate design disparity could result in producers bypassing Transco s offshore facilities in favor of alternative transportation facilities. Transco has asked FERC to allow it to eliminate the IT feeder charge and charge for transportation on its offshore facilities in the same manner as other pipelines. Transco s requests have been denied.

The rates, terms and conditions for the Pipeline Entities interstate pipeline services are set forth in their respective FERC-approved tariffs. Any successful complaint or protest against the Pipeline Entities rates could have an adverse impact on their revenues associated with providing transportation services. In addition, there is a risk that rates set by the FERC in future rate cases filed by the Pipeline Entities 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.

The Pipeline Entities could be subject to penalties and fines if they fail to comply with FERC regulations.

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

The outcome of certain FERC proceedings involving FERC policy statements is uncertain and could affect the level of return on equity that the Pipeline Entities may be able to achieve in any future rate proceeding.

In an effort to provide some guidance and to obtain further public comment on FERC s policies concerning return on equity determinations, on July 19, 2007, FERC issued its Proposed Proxy Policy Statement, Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity. In the Proposed Proxy Policy Statement, FERC proposes to permit inclusion of publicly traded partnerships in the proxy group analysis relating to return on equity determinations in rate proceedings, provided that the analysis be limited to actual publicly traded partnership distributions capped at the level of the pipeline s earnings.

After receiving public comment on the proposed policy statement, on April 17, 2008, FERC issued a final policy statement rejecting the concept of capping distributions in favor of an adjustment to the long-term growth rate used to calculate the equity cost of capital for publicly traded partnerships which are included in the proxy group.

On January 19, 2009, the FERC applied the policy statement to a pipeline rate case and determined that the pipeline s return on equity should be 11.55 percent. It is difficult to know how instructive this case is for purposes of anticipating rates of return in future rate cases, because the FERC determined the composition of the proxy group using data from 2004 when the case was filed.

The effect of the application of FERC s policy to the Pipeline Entities future rate proceedings is not certain, and we cannot ensure that such application would not adversely affect our ability to achieve a reasonable level of return on equity.

The outcome of future rate cases to set the rates the Pipeline Entities can charge customers on their respective pipelines might result in rates that lower their return on the capital invested in those pipelines.

There is a risk that rates set by the FERC in the Pipeline Entities future rate cases 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 will cause their customers to look for alternative ways to transport their natural gas.

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The outcome of future rate cases will determine the amount of income taxes the Pipeline Entities will be allowed to recover.

In May 2005, the FERC issued a statement of general policy permitting a pipeline to include in its cost-of-service computations an income tax allowance provided that an entity or individual has an actual or potential income tax liability on income from the pipeline s public utility assets. The extent to which owners of pipelines have such actual or potential income tax liability will be reviewed by FERC on a case-by-case basis in rate cases where the amounts of the allowances will be established.

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

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

Certain inquiries, investigations and court proceedings are ongoing. Adverse effects may continue as a result of the uncertainty of these ongoing inquiries and proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against the Pipeline Entities, civil or criminal fines or penalties, or other regulatory action, including legislation, which might be materially adverse to the operation of the Pipeline Entities businesses and our revenues and net income or increase their operating costs in other ways. Current legal proceedings or other matters against us including environmental matters, suits, regulatory appeals and similar matters might result in adverse decisions against the Pipeline Entities. 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.

Increased competition from alternative natural gas transportation and storage options and alternative fuel sources could have a significant financial impact on us.

We compete primarily with other interstate pipelines and storage facilities in the transportation and storage of natural gas. Some of our competitors may have greater financial resources and access to greater supplies of natural gas than we do. Some of these competitors may expand or construct transportation and storage systems that would create additional competition for natural gas supplies or the services we provide to our customers. Moreover, Williams and its other affiliates may not be limited in their ability to compete with us. Further, natural gas also competes with other forms of energy available to our customers, including electricity, coal, fuel oils and other alternative energy sources.

The principal elements of competition among natural gas transportation and storage assets are rates, terms of service, access to natural gas supplies, flexibility and reliability. FERC s policies promoting competition in natural gas markets are having the effect of increasing the natural gas transportation and storage options for our traditional customer base. As a result, we could experience some turnback of firm capacity as the primary terms of existing agreements expire. If we are unable to remarket this capacity or can remarket it only at substantially discounted rates compared to previous contracts, we or our remaining customers may have to bear the costs associated with the turned back capacity. Increased competition could reduce the amount of transportation or storage capacity contracted on our system or, in cases where we do not have long-term fixed rate contracts, could force us to lower our transportation or storage rates. Competition could intensify the negative impact of factors that significantly decrease demand for natural gas or increase the price of natural gas in the markets served by our pipeline system, such as competing or alternative forms of energy, a regional or national recession or other adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the price of natural gas or limit the use of natural gas. Our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors. All of these competitive pressures could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to make cash distributions to unitholders.

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.

The Pipeline Entities primary exposure to market risk occurs at the time the terms of existing transportation and storage contracts expire and are subject to termination. Although none of our material contracts are terminable in 2010, 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; and
- 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 and our ability to make cash distributions to unitholders.

Competitive pressures could lead to decreases in the volume of natural gas contracted or transported through the Pipeline Entities pipeline systems.

Although most of the Pipeline Entities pipeline systems current capacity is fully contracted, the FERC has taken certain actions to strengthen market forces in the natural gas pipeline industry that have led to increased competition throughout the industry. In a number of key markets, interstate pipelines are now facing competitive pressure from other major pipeline systems, enabling local distribution companies and end users to choose a transmission provider based on considerations other than location. Other entities could construct new pipelines or expand existing pipelines that could potentially serve the same markets as our pipeline system. Any such new pipelines could offer transportation services that are more desirable to shippers because of locations, facilities, or other factors. These new pipelines could charge rates or provide service to locations that would result in greater net profit for shippers and producers and thereby force us to lower the rates charged for service on our pipeline in order to extend our existing transportation service agreements or to attract new customers. We are aware of proposals by competitors to expand pipeline capacity in certain markets we also serve which, if the proposed projects proceed, could increase the competitive pressure upon us. There can be no assurance that we will be able to compete successfully against current and future competitors and any failure to do so could have a material adverse effect on our business, results of operations, and our ability to make cash distributions to unitholders.

Decreases in demand for natural gas could adversely affect our business.

Demand for our transportation services depends on the ability and willingness of shippers with access to our facilities to satisfy their demand by deliveries through our system. Any decrease in this demand could adversely affect our business. Demand for natural gas is also affected by weather, future industrial and economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation, or technological advances in fuel economy and energy generation devices, all of which are matters beyond our control. Additionally, in some cases, new LNG import facilities built near our markets could result in less demand for our gathering and transmission facilities.

The failure of new sources of natural gas production or LNG import terminals to be successfully developed in North America could increase natural gas prices and reduce the demand for our services.

New sources of natural gas production in the United States and Canada, particularly in areas of shale development are expected to become an increasingly significant component of future U.S. natural gas supply in North America.

Additionally, increases in LNG supplies are expected to be imported through new LNG import terminals, particularly in the Gulf Coast region. If these additional sources of supply are not developed, natural gas prices could increase and cause consumers of natural gas to turn to alternative energy sources, which could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to make cash distributions to unitholders.

Certain of the Pipeline Entities 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.

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

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

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

- hurricanes, tornadoes, floods, fires, extreme weather conditions and other natural disasters;
- aging infrastructure and mechanical problems;
- damages to pipelines and pipeline blockages;
- uncontrolled releases of natural gas (including sour gas), NGLs, brine or industrial chemicals;
- collapse of NGL storage caverns;
- operator error;
- damage inadvertently 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; and
- terrorist attacks or threatened attacks on our facilities or those of other energy companies.

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

Some portions of our current pipeline infrastructure and other assets have been in use for many decades, which may adversely affect our business.

Some portions of our assets, including our pipeline infrastructure, have been in use for many decades. The current age and condition of our assets could result in a material adverse impact on our business, financial condition and results of operations if the costs of maintaining our facilities exceed current expectations.

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

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

- CAA and analogous state laws, which impose obligations related to air emissions;

- CWA, and analogous state laws, which regulate discharge of wastewaters from our facilities to state and federal waters;

- 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; and

- RCRA, and analogous state laws, which impose requirements for the handling and discharge of solid and hazardous waste from our facilities.

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

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

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation 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 make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change, and any new capital costs incurred to comply with such changes may not be recoverable under our regulatory rate structure or our customer contracts. In addition, new environmental laws and regulations might adversely affect our products and activities, including processing, fractionation, storage and transportation, as well as waste management and air emissions. For instance, federal and state agencies could impose additional safety requirements, any of which could affect our profitability. In addition, recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases (GHGs), may be contributing to warming of the earth s atmosphere, and various governmental bodies have considered legislative and regulatory responses in this area.

Legislative and regulatory responses related to GHGs and climate change creates the potential for financial risk. The United States 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.

Several bills have been introduced in the United States Congress that would compel GHG emission reductions. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act which is intended to decrease annual GHG emissions through a variety of measures, including a cap and trade system which limits the amount of GHGs that may be emitted and incentives to reduce the nation s dependence on traditional energy sources. The U.S. Senate is currently considering similar legislation, and numerous states have also announced or adopted programs to stabilize and reduce GHGs. In addition, on December 7, 2009, the EPA issued a final determination that six GHGs are a threat to public safety and welfare. This determination could ultimately lead to the direct regulation of GHG emissions in our industry under the CAA. While it is not clear whether or when any federal or state climate change laws or regulations will be passed, any of these actions 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 our ability to make cash distributions to unitholders. 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.

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

We are not fully insured against all risks inherent to our business, including environmental accidents that might occur. In addition, we do not maintain business interruption 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 aggregate annually and a deductible of $2 million per occurrence. This insurance covers us, our subsidiaries, and certain of our affiliates for legal and contractual liabilities arising out of bodily injury, personal 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. Pollution liability coverage excludes: release of pollutants subsequent to their disposal; release of substances arising from the combustion of fuels that result in acidic deposition, and testing, monitoring, clean-up, containment, treatment or removal of pollutants from property owned, occupied by, rented to, used by or in the care, custody or control of us, our subsidiaries, or certain of our affiliates.

We do not insure onshore underground pipelines for physical damage, except at river crossings and at certain locations such as compressor stations. We maintain coverage of $300 million per occurrence for physical damage to onshore assets and resulting business interruption caused by terrorist acts. We also maintain coverage of $100 million per occurrence for physical damage to offshore assets caused by terrorist acts, except for our Devils Tower spar where we maintain limits of $300 million per occurrence for property damage caused by terrorist acts and $105 million per occurrence for resulting business interruption. Also, 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. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. Changes in the insurance markets subsequent to hurricanes losses in recent years have impacted named windstorm insurance coverage, rates and availability for Gulf of Mexico area exposures, and we may elect to self insure a portion of our asset portfolio. We cannot assure you that we will in the future be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes or that the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating 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 make cash distributions to unitholders.

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In addition, certain insurance companies that provide coverage to us, including American International Group, Inc., have experienced negative developments that could impair their ability to pay any of our potential 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.

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

Our growth may be dependent upon the construction of new natural gas gathering, transportation, 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; and

- the ability to access capital markets to fund construction projects.

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

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

Revenues from certain segments of our business can have seasonal characteristics. In many parts of the country, demand for natural gas and other fuels peaks during the winter. As a result, our overall operating results in the future might fluctuate substantially on a seasonal basis. Demand for natural gas and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and pipeline systems and the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns.

We do not operate all of our assets. This reliance on others to operate our assets and to provide other services could adversely affect our business and operating results.

Williams and other third parties operate certain of our assets. We have a limited ability to control these operations and the associated costs. The success of these operations is therefore dependent upon a number of factors that are outside our control, including the competence and financial resources of the operators.

We rely on Williams for certain services necessary for us to be able to conduct our business. Williams may outsource some or all of these services to third parties, and a failure of all or part of Williams relationships with its outsourcing providers could lead to delays in or interruptions of these services. Our reliance on Williams and others as operators and on Williams outsourcing relationships, and our limited ability to control certain costs could have a material adverse effect on our business, results of operations, and financial condition and our ability to make cash distributions to unitholders.

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. 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. 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 our ability to make cash distributions to unitholders.

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

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

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

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

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

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

Certain of our accounting, information technology, application development, and help desk services are currently provided by Williams outsourcing provider from service centers outside of the United States. The economic and political conditions in certain countries from which Williams 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.

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

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

Risks Inherent in an Investment in Us

We may not realize the anticipated benefits from the Dropdown.

We may not realize the benefits that we anticipate from the Dropdown for a number of reasons, including, but not limited to, if any of the matters identified as risks in this Risk Factors section were to occur. If we do not realize the anticipated benefits from the Dropdown for any reason, our business may be materially adversely affected.

Williams did not seek a vote of its shareholders in connection with the Dropdown. If there is a determination that such a vote was required, the resulting consequences could impact us.

Section 271 of the Delaware General Corporation Law (the DGCL) generally requires a corporation to obtain authorization from the holders of a majority of its outstanding shares if the corporation intends to sell all or substantially all of its assets. Williams does not believe the Dropdown constituted a sale of all or substantially all of its assets because of, among other things, the portion of Williams assets involved, the significance of its assets and businesses that were not transferred and the facts that Williams retains control of all of the assets involved and over an 80% interest in the cash flows therefrom. As such, Williams did not seek a vote of its shareholders in connection with the Dropdown. There is a limited body of Delaware case law interpreting the phrase all or substantially all, and there is no precise established definition. We cannot assure you that the Dropdown does not constitute a sale of all or substantially all of Williams assets and, therefore, that a shareholder vote was not required. If such a shareholder vote were determined to be required, the resulting consequences could impact us and could include (among other consequences) shareholders of Williams asserting claims against us, some or all of which could ultimately be successful.

We will have certain indemnification obligations in favor of Williams subsequent to the completion of the Dropdown.

In connection with the Dropdown, we have agreed to indemnify Williams, its affiliates (other than us and our securityholders, officers, directors and employees) and its respective securityholders, officers, directors and employees against certain losses resulting from any breach of our representations, warranties, covenants or agreements contained in the Contribution Agreement. These indemnification obligations could be significant. We cannot determine whether we will have to indemnify Williams or its affiliates for any substantial obligations after the Dropdown has become effective. We also cannot provide any assurance that if Williams has to indemnify us for any substantial obligations after the Dropdown has become effective, Williams will be able to satisfy such obligations.

Williams controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates have conflicts of interest with us and limited fiduciary duties, and they may favor their own interests to the detriment of our unitholders.

Williams owns and controls our general partner and appoints all of the directors of our general partner. All of the executive officers and certain directors of our general partner are officers and/or directors of Williams and its affiliates, including WMZ s general partner. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to Williams. Therefore, conflicts of interest may arise between Williams and its affiliates, including our general partner and WMZ, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following factors:

- neither our partnership agreement nor any other agreement requires Williams or its affiliates to pursue a business strategy that favors us. Williams directors and officers have a fiduciary duty to make decisions in the best interests of the owners of Williams, which may be contrary to ours;

- all of the executive officers and certain of the directors of our general partner are also officers and/or directors of Williams and WMZ s general partner, and these persons will also owe fiduciary duties to those entities;

- our general partner is allowed to take into account the interests of parties other than us, such as Williams and its affiliates, in resolving conflicts of interest;

- Williams owns common units representing an 82% limited partner interest in us, and if a vote of limited partners is required, Williams will be entitled to vote its units in accordance with its own interests, which may be contrary to our interests or your interests;

all of the executive officers and certain of the directors of our general partner will devote significant time to the business of Williams and/or Williams Partners, and will be compensated by Williams for the services rendered to them;

our general partner determines the amount and timing of our cash reserves, asset purchases and sales, capital expenditures, borrowings and issuances of additional partnership securities, each of which can affect the amount of cash that is distributed to our unitholders;

our general partner determines the amount and timing of any capital expenditures and, based on the applicable facts and circumstances, whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure or investment capital expenditure, neither of which reduces operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner with respect to its incentive distribution rights;

in some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions even if the purpose or effect of the borrowing is to make incentive distributions to our general partner;

our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

our general partner intends to limit its liability regarding our contractual and other obligations and in some circumstances is required to be indemnified by us;

our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 85% of the common units;

our general partner controls the enforcement of obligations owed to us by it and its affiliates; and

our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement limits our general partner s fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. The limitation and definition of these duties is permitted by the Delaware law governing limited partnerships. In addition, our partnership agreement restricts the remedies available to holders of our limited partner units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty. For example, our partnership agreement:

permits our general partner to make a number of decisions in its individual capacity as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement;

provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;

generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us, as determined by our general partner in good faith. In determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;

provides that our general partner, its affiliates and their officers and directors will not be liable for monetary damages to us or our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct; and provides that in resolving conflicts of interest, it will be presumed that in making its decision our general partner or the conflicts committee of its board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Common unitholders are bound by the provisions in the partnership agreement, including the provisions discussed above.

Affiliates of our general partner, including Williams, may not be limited in their ability to compete with us. Williams is also not obligated to offer us the opportunity to acquire additional assets or businesses from it, which could limit our commercial activities or our ability to grow. In addition, all of the executive officers and certain of the directors of our general partner are also officers and/or directors of Williams, and these persons will also owe fiduciary duties to it.

While our relationship with Williams and its affiliates is a significant attribute, it is also a source of potential conflicts. For example, Williams is in the natural gas business and is not restricted from competing with us. Williams and its affiliates may compete with us. Williams and its affiliates may acquire, construct or dispose of natural gas industry assets in the future, some or all of which may compete with our assets, without any obligation to offer us the opportunity to purchase or construct such assets. In addition, all of the executive officers and certain of the directors of our general partner are also officers and/or directors of Williams and WMZ s general partner and will owe fiduciary duties to those entities as well as our unitholders and us.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which the common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner, including the independent directors, will be chosen entirely by Williams and not by the unitholders. Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders. Furthermore, if the unitholders become dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Cost reimbursements due to our general partner and its affiliates will reduce cash available to pay distributions to unitholders.

We will reimburse our general partner and its affiliates, including Williams, for various general and administrative services they provide for our benefit, including costs for rendering administrative staff and support services to us, and overhead allocated to us. Our general partner determines the amount of these reimbursements in its sole discretion. Payments for these services will be substantial and will reduce the amount of cash available for distributions to unitholders. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Even if unitholders are dissatisfied, they have little ability to remove our general partner without its consent.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by Williams. As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Furthermore, if our unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The vote of the holders of at least 66 2/3% of all outstanding common units is required to remove our general partner.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make payments on our debt obligations and distributions on our common units.

We have a holding company structure, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in these subsidiaries. As a result, our ability to make required payments on our debt obligations and distributions on our common units depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, applicable state partnership and limited liability company laws and other laws and regulations. If we are unable to obtain the funds necessary to pay the principal amount at maturity of our debt obligations, to repurchase our debt obligations upon the occurrence of a change of control or make distributions on our common units, we may be required to adopt one or more alternatives, such as a refinancing of our debt obligations or borrowing funds to make distributions on our common units. We cannot assure you that we would be able to borrow funds to make distributions on our common units.

Our allocation from Williams for costs for its defined benefit pension plans and other postretirement benefit plans are affected by factors beyond our and Williams control.

As we have no employees, employees of Williams and its affiliates provide services to us. As a result, we are allocated a portion of Williams costs in defined benefit pension plans covering substantially all of Williams or its affiliates employees providing services to us, as well as a portion of the costs of other postretirement benefit plans covering certain eligible participants providing services to us. The timing and amount of our allocations under the defined benefit pension plans depend upon a number of factors Williams controls, including changes to pension plan benefits, as well as factors outside of Williams control, such as asset returns, interest rates and changes in pension laws. Changes to these and other factors that can significantly increase our allocations could have a significant adverse effect on our financial condition and results of operations.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement effectively permits a change of control without your consent.

We may issue additional common units without unitholder approval, which would dilute unitholder ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders proportionate ownership interest in us will decrease;
- the amount of cash available to pay distributions on each unit may decrease;
- the ratio of taxable income to distributions may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Common units held by Williams eligible for future sale may adversely affect the price of our common units.

As of December 31, 2009, Williams held 11,613,527 common units, representing a 21.6% limited partnership interest in us. After the Dropdown, Williams held 214,613,527 common units and Class C units, representing an 82% limited partnership interest in us. Williams may, from time to time, sell all or a portion of its common units. Sales of substantial amounts of its common units, or the anticipation of such sales, could lower the market price of our common units and may make it more difficult for us to sell our equity securities in the future at a time and at a price that we deem appropriate.

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Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. In connection with the closing of the Dropdown, we entered into a limited call right forbearance agreement with our general partner, pursuant to which our general partner agreed not to exercise this right unless it and its affiliates hold more than 85% of our common limited partner units. The forbearance agreement will terminate when the ownership by our general partner and its affiliates of our common limited partner units decreases below 75% (assuming the full conversion of Class C Units that are held by our general partner and its affiliates). Our general partner may assign this right to any of its affiliates or to us. As a result, non-affiliated unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Such unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would not longer be subject to the reporting requirements of the Securities Exchange Act of 1934.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders voting rights by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot be voted on any matter. The partnership agreement also contains provisions limiting the ability of unitholders to call meetings, to acquire information about our operations and to influence the manner or direction of management.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state s partnership statute; or

- your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute control of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by states and localities. If the Internal Revenue Service

(IRS) were to treat us as a

corporation or if we were to become subject to a material amount of entity-level taxation for state or local tax purposes, then our cash available for distribution to unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which currently has a top marginal rate of 35%, and would likely pay state and local income tax at the corporate tax rate of the various states and localities imposing a corporate income tax. Distributions to unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available to pay distributions to unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders, likely causing a substantial reduction in the value of the common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distributions to unitholders would be reduced. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation (the Qualifying Income Exception), affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Internal Revenue Code Section 7704(d) and the treatment of certain types of income earned from profits interests in partnerships. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Modifications to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of the common units each month based upon the ownership of the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of the common units each month based upon the ownership of the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

An IRS contest of the federal income tax positions we take may adversely impact the market for the common units, and the costs of any contest will reduce our cash available for distribution to our unitholders and our general partner.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel s conclusions or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not agree with some or all of our counsel s conclusions or the federal income tax positions we take. Any contest with the IRS may materially and adversely impact the market for the common units and the price at which they trade. In addition, the costs of any contest with the IRS will result in a reduction in cash available to pay distributions to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner.

Unitholders will be required to pay taxes on their share of our income even if unitholders do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

The tax gain or loss on the disposition of the common units could be different than expected.

If a unitholder sells its common units, it will recognize gain or loss equal to the difference between the amount realized and its tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income that was allocated to a unitholder for a common unit, which decreased its tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than its tax basis in that common unit, even if the price the unitholder receives is less than its original cost. A substantial portion of the amount realized, regardless of whether such amount represents gain, may be taxed as ordinary income to the unitholder due to potential recapture items, including depreciation recapture. In addition, if a unitholder sells its common units, the unitholder may incur a tax liability in excess of the amount of cash it received from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to the unitholders who are organizations that are exempt from federal income tax, including IRAs and other retirement plans, may be taxable to them as unrelated business taxable income. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

We will treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury regulations. Our counsel is unable to opine as to the validity of such filing positions. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to unitholder tax returns.

Unitholders will likely be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance, or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if the unitholder does not live in any of those jurisdictions. Unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign countries that impose a personal income tax or an entity level tax. It is the unitholder s responsibility to file all federal, state and local tax returns. Our counsel has not rendered an opinion on the state and local tax consequences of an investment in our common units.

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The sale or exchange of 50% or more of the total interest in our capital and profits within a 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one fiscal year. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than 12 months of our taxable income or loss being includable in the unitholder s taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from a unitholder s sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the unitholder s tax returns.

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

None.

Item 3. ***Legal Proceedings***

The information called for by this item is provided below and in Note 16, Commitments and Contingencies, in our Notes to Consolidated Financial Statements of this report, which information in Note 16 is incorporated into this Item 3 by reference.

Environmental Matters

Since 1989, Transco has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At December 31, 2009, Transco had accrued liabilities of $4.7 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, Transco has estimated its aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above. We expect that these costs will be recoverable through Transco s rates.

Beginning in the mid-1980s, Northwest Pipeline evaluated many of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation might be necessary. Consistent with other natural gas transmission companies, Northwest Pipeline identified PCB contamination in air compressor systems, soils and related properties at certain compressor station sites. Similarly, Northwest Pipeline identified hydrocarbon impacts at these facilities due to the former use of earthen pits and mercury contamination at certain gas metering sites. The PCBs were remediated pursuant to a Consent Decree with the EPA in the late 1980s and Northwest Pipeline conducted a voluntary clean-up of the hydrocarbon and mercury impacts in the early 1990s. In 2005, the Washington Department of Ecology required Northwest Pipeline to reevaluate its previous mercury clean-ups in Washington. Consequently, Northwest Pipeline is conducting additional remediation activities at certain sites to comply with Washington s current environmental standards. At December 31, 2009 Northwest Pipeline accrued liabilities of $7.8 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

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 our compliance with the Clean Air Act. On March 28, 2008, the EPA issued notice of violations alleging violations of Clean Air Act requirements at these compressor stations. Transco met with the EPA in May 2008 and submitted its response denying the allegations in June 2008. In July 2009, the EPA requested additional information pertaining to these compressor stations and in August 2009, Transco submitted the requested information.

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

None.

PART II

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

Market Information, Holders and Distributions

Our common units are listed on the New York Stock Exchange under the symbol WPZ. At the close of business on February 18, 2010, there were 52,777,452 common units outstanding, held by approximately 29,122 holders, including common units held in street name and by affiliates of Williams.

As of February 18, 2010, there were 203,000,000 Class C units outstanding, held by three subsidiaries of Williams. The Class C units are not publicly traded. Our Class C units are identical to our common units except that the quarterly distribution they receive with respect to first quarter 2010 will be prorated to reflect the fact that the Class C units were not outstanding during the full quarterly period. The Class C units will automatically convert into common units following the record date for the distribution with respect to the first quarter of 2010. Our general partner holds all of our 2% general partner interest and incentive distribution rights. As part of the consideration for the Dropdown, we increased the capital account of our general partner to allow it to maintain its 2% general partner interest and issued additional general partner units to our general partner equal to $2/98^{th}$ of the number of Class C units issued (Additional GP Units). Distributions on the Additional GP Units with respect to the first quarter 2010 will also be prorated to reflect that they were not outstanding during the full quarterly period.

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The following table sets forth, for the periods indicated, the high and low sales prices for our common units, as reported on the New York Stock Exchange Composite Transactions Tape, and quarterly cash distributions paid to our unitholders.

	High	Low	Cash Distribution per Unit(a)
2009			
Fourth Quarter	$32.23	$22.20	$0.635
Third Quarter	23.80	17.10	0.635
Second Quarter	19.70	10.89	0.635
First Quarter	17.88	8.54	0.635
2008			
Fourth Quarter	$26.25	$ 9.96	$0.635
Third Quarter	32.84	22.77	0.635
Second Quarter	37.66	31.33	0.625
First Quarter	39.31	31.24	0.600

(a) Represents cash distributions attributable to the quarter and declared and paid within 45 days after quarter end. We paid cash distributions to our general partner with respect to its 2% general partner interest and incentive distribution rights that totaled $2.7 million and $30.0 million for the 2009 and 2008 periods, respectively.

Distributions of Available Cash

Within 45 days after the end of each quarter we will distribute all of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. Available cash generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

less the amount of cash reserves established by our general partner to:

provide for the proper conduct of our business (including reserves for future capital expenditures and for our anticipated credit needs);

- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distribution to our unitholders and to our general partner for any one or more of the next four quarters;

plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made. Working capital borrowings are borrowings used solely for working capital purposes or to pay distributions made pursuant to a credit facility or other arrangement to the extent such borrowings are required to be reduced to a relatively small amount each year for an economically meaningful period of time.

Subject to the proration on the distribution that Class C unitholders and the Additional GP Units will receive with respect to the first quarter of 2010 described above, we will make distributions of available cash from operating surplus for any quarter in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to our general partner, until each outstanding unit has received the minimum quarterly distribution for that quarter; and
- *thereafter*, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the incentive percentages below.

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Our general partner is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	Unitholders	General Partner
Minimum Quarterly Distribution	$0.35	98%	2%
First Target Distribution	up to $0.4025	98%	2%
Second Target Distribution	above $0.4025 up to $0.4375	85%	15%
Third Target distribution	above $0.4375 up to $0.5250	75%	25%
Thereafter	Above $0.5250	50%	50%

If the unitholders remove our general partner other than for cause and units held by our general partner and its affiliates are not voted in favor of such removal:

- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and

- our general partner will have the right to convert its general partner interest and, if any, its incentive distribution rights into common units or to receive cash in exchange for those interests.

The preceding discussion is subject to the proration on the distribution that the Additional GP Units will receive with respect to the first quarter of 2010 described above and is based on the assumption that our general partner maintains its 2% general partner interest and that we do not issue additional classes of equity securities. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Financial Condition and Liquidity.

Item 6. ***Selected Financial and Operational Data***

The following table shows our selected financial and operating data and selected financial and operating data of Wamsutter and Discovery for the periods and as of the dates indicated and do not reflect the consummation of the Dropdown. We derived the financial data as of December 31, 2009 and 2008 and for the years ended December 31, 2009, 2008 and 2007 in the following table from, and that information should be read together with, and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this document. All other financial data are derived from our financial records.

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The table should also be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations for information concerning significant trends in the financial condition and results of operations.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(Dollars in thousands, except per-unit amounts)				
Statement of Income Data:					
Revenues	$ 470,189	$ 637,060	$ 572,817	$ 563,410	$ 514,972
Costs and expenses	368,437	490,052	457,880	420,342	395,556
Operating income	101,752	147,008	114,937	143,068	119,416
Equity earnings Wamsutter	84,052	88,538	76,212	61,690	40,555
Discovery investment income	27,243	22,357	28,842	18,050	11,880
Interest expense	(60,679)	(67,220)	(58,348)	(9,833)	(8,238)
Interest income	99	706	2,988	1,600	165
Income before cumulative effect of change in accounting principle	$ 152,467	$ 191,389	$ 164,631	$ 214,575	$ 163,778
Net income(a)	$ 152,467	$ 191,389	$ 164,631	$ 214,575	$ 162,373
Income before cumulative effect of change in accounting principle per limited partner unit:					
Common unit	$ 2.88	$ 3.08	$ 1.99	$ 1.73	$ 0.49(b)
Subordinated unit	N/A	N/A	$ 1.99	$ 1.73	$ 0.49(b)
Net income per limited partner unit:					
Common unit	$ 2.88	$ 3.08	$ 1.99	$ 1.73	$ 0.44(b)
Subordinated unit	N/A	N/A	$ 1.99	$ 1.73	$ 0.44(b)
Balance Sheet Data (at period end):					
Total assets	$ 1,323,670	$ 1,291,819	$ 1,283,477	$ 1,292,299	$ 1,190,508
Property, plant and equipment, net	634,233	640,520	642,289	647,578	658,965
Investment in Wamsutter	272,549	277,707	284,650	262,245	240,156
Investment in Discovery	188,511	184,466	214,526	221,187	225,337
Long-term debt	1,000,000	1,000,000	1,000,000	750,000	
Partners capital	215,395	203,610	161,487(c)	471,341(c)	1,142,478
Cash Flow Data:					
Cash distributions declared per unit	$ 2.540	$ 2.435	$ 2.045	$ 1.605	$ 0.1484
Cash distributions paid per unit	$ 2.540	$ 2.435	$ 2.045	$ 1.605	$ 0.1484
Operating Information:					
Williams Partners L.P.:					

Four Corners gathering volumes (BBtu/d)	1,344	1,380	1,442	1,500	1,522
Four Corners plant inlet natural gas volumes (BBtu/d)	620	646	620	678	685
Four Corners NGL equity sales (million gallons)	164	162	167	182	165
Four Corners NGL margin ($/gallon)	$ .44	$ .75	$ .61	$ .47	$ .37
Four Corners NGL production (million gallons)	525	518	545	569	550
Conway storage revenues	$ 33,209	$ 31,429	$ 28,016	$ 25,237	$ 20,290
Conway fractionation volumes (bpd) our 50%	38,594	39,019	34,460	38,859	39,965
Carbonate Trend gathering volumes (BBtu/d)	18	22	23	29	36
Wamsutter 100%:					
Wamsutter gathering volumes (BBtu/d)	537	499	516	490	464
Wamsutter plant inlet natural gas volumes (BBtu/d)	423	409	425	432	422
Wamsutter NGL equity sales (million gallons)	149	139	113	141	160
Wamsutter NGL margin ($/gallon)	$ .39	$ .59	$ .48	$ .29	$ .13
Wamsutter NGL production (million gallons)	447	415	420	377	419
Discovery Producer Services 100%:					
Discovery plant inlet natural gas volumes (BBtu/d)	485	457	582	467	345
Discovery gross processing margin ($/MMbtu)	$ .26	$ .37	$ .33	$ .23	$ .19
Discovery NGL equity sales (million gallons)	94	85	99	60	38
Discovery NGL production (million gallons)	250	181	252	232	147

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(a) Our operations are treated as a partnership with each member being separately taxed on its ratable share of our taxable income.

(b) The period of August 23, 2005 through December 31, 2005.

(c) Because Four Corners, Wamsutter and a 20% interest in Discovery were owned by affiliates of Williams at the time of their acquisition by us, the acquisitions are accounted for as a combination of entities under common control, whereby the assets and liabilities acquired are combined with ours at their historical amounts for all periods presented. This accounting causes a reduction of the capital balance for the general partner for the difference between the historical cost of these assets and liabilities and the aggregate consideration paid to the general partner.

Item 7. ***MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS***

Please read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and related notes included in Item 8 of this annual report.

Recent Developments

The Dropdown

On February 17, 2010, we closed a transaction with our general partner, our operating company, The Williams Companies, Inc. (Williams) and certain subsidiaries of Williams, pursuant to which Williams contributed to us the ownership interests in the entities that make up Williams Gas Pipeline and Midstream Gas & Liquids business segments, to the extent not already owned by us, including Williams limited and general partner interests in Williams Pipeline Partners L.P. (WMZ), but excluding Williams Canadian, Venezuelan and olefin operations and 25.5% of Gulfstream Natural Gas System, L.L.C. (Gulfstream). Such entities are hereafter referred to as the Contributed Entities . This contribution was made in exchange for aggregate consideration of:

$3.5 billion in cash, less certain expenses incurred by us relating to our acquisition of the Contributed Entities. This cash consideration was financed through the private issuance of $3.5 billion of senior unsecured notes with net proceeds of $3.466 billion.

203 million of our Class C limited partnership units, which are identical to our common limited partnership units except that for the distribution with respect to the first quarter of 2010 they will receive a prorated quarterly distribution since they were not outstanding during the full quarterly period. The Class C units will automatically convert into our common limited partnership units following the record date for the distribution with respect to the first quarter of 2010.

an increase in the capital account of our general partner to allow it to maintain its 2% general partner interest.

The transactions described in the preceding paragraph are referred to as the Dropdown.

Beginning with reporting of first-quarter 2010 results, our operations will be divided into two business segments: Gas Pipeline and Midstream Gas & Liquids. All of the operations we conducted prior to the Dropdown will be reported within the Midstream Gas & Liquids segment. The Contributed Entities business activities will be included in our two business segments as follows:

Gas Pipeline will include Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline GP (Northwest Pipeline), which own and operate a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,700 TBtu of natural gas and peak-day delivery capacity of approximately 12 MMdt of natural gas. Gas Pipeline will also hold interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5% interest in Gulfstream, which owns an approximate 745-mile pipeline with the capacity to transport approximately 1.26 million Dth per day of natural gas.

Midstream Gas & Liquids will include the Contributed Entities natural gas gathering, processing and treating facilities located primarily in the Rocky Mountain and Gulf Coast regions of the United States and natural gas and crude oil gathering and transportation facilities in the Gulf Coast region of the United States.

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WMZ Exchange Offer

We have also announced our intention to launch an exchange offer for the publicly traded common units of WMZ at a future date (the WMZ Exchange Offer). We will offer a fixed exchange ratio of 0.7584 of our common units for each WMZ common unit. The ratio is based on closing prices on the New York Stock Exchange on Friday, January 15, 2010, the business date before our intention to make the exchange offer was announced, of $23.35 for WMZ and $30.79 for us. The exact timing of the launch will be based upon the filing of necessary offering documents with the Securities and Exchange Commission and upon market conditions. Please read Business and Properties Recent Events WMZ Exchange Offer for more information.

New Credit Facility

In connection with the Dropdown, we entered into a new $1.75 billion senior unsecured revolving three-year credit facility with Transco and Northwest Pipeline, as co-borrowers with borrowing sublimits of $400 million each, and Citibank, N.A. as administrative agent, and other lenders named therein (New Credit Facility). The New Credit Facility replaced our previous $450 million senior unsecured credit agreement. At the closing of the Dropdown, we borrowed $250 million under the New Credit Facility to repay the term loan outstanding under our existing credit facility.

Overview

The following discussion of our results of operations reflects our business as it existed prior to the Dropdown and as reflected in the consolidated financial statements and related notes included in Item 8 of this annual report.

During 2009, and in earlier periods, we were principally engaged in the business of gathering, transporting, processing and treating natural gas and fractionating and storing natural gas liquids (NGLs). We managed our business and analyzed our results of operations on a segment basis. Our operations were divided into three business segments: *Gathering and Processing West (West), Gathering and Processing Gulf (Gulf) and NGL Services*. (Please read Note 17, Segment Disclosures, in our Notes to Consolidated Financial Statements for further discussion of these segments.) The Dropdown transaction represents a dramatic expansion in the scale, scope and diversification of our operations and our prospects for growth.

Our operating results throughout the second half of 2009 demonstrated significant continued improvement from difficult circumstances experienced during the last quarter of 2008 and the first half of 2009 when low NGL commodity prices and hurricane-related damages significantly decreased the profitability of our gathering and processing businesses. These circumstances resulted in significantly lower results of operations and cash flow from operations in 2009 compared to 2008. During 2009, Williams provided us with significant, additional support, which assisted us in maintaining a higher level of cash retention and a stronger overall liquidity position. Williams waived its incentive distribution rights (IDRs) related to the 2009 distribution periods. These IDRs represented approximately $29.0 million, on an annual basis. In addition, our omnibus agreement with Williams was amended to increase the aggregate amount of the credit we could receive related to certain general and administrative expenses for 2009. Williams additional support during 2009 combined with the improved commodity environment in the second half of 2009 allowed us to maintain our prior per-unit level of cash distributions throughout 2009.

Critical Accounting Policies and Estimates

Our financial statements reflect the selection and application of accounting policies that require management to make significant estimates and assumptions. The selection of these policies has been discussed with the audit committee of the board of directors of our general partner. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Accounting for Asset Retirement Obligations

We record asset retirement obligations for legal and contractual obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset in the period in which it is incurred if a reasonable estimate of fair value can be made. At December 31, 2009, we have accrued asset retirement obligations of $14.8 million including estimated retirement costs associated with the abandonment of Four Corners gas processing and compression facilities located on leased land, Four Corners wellhead connections on federal land, Conway s underground storage caverns and brine ponds in accordance with Kansas Department of Health and Environment (KDHE) regulations and the Carbonate Trend pipeline. Our estimate utilizes judgments and assumptions regarding the extent of our obligations, the costs to abandon and the timing of abandonment. In 2009, we revised our estimated asset retirement obligations by $0.4 million. Our recorded asset retirement obligation is based on the assumption that the abandonment of our Four Corners and Conway assets generally occurs in approximately 50 years. If this assumption had been changed to 30 years, and the expected retirement date for the Carbonate Trend pipeline had been significantly shortened, the recorded asset retirement obligation would have increased by an additional $12.0 million to $14.0 million. (Please read Note 9, Property, Plant and Equipment, in our Notes to Consolidated Financial Statements.)

Environmental Remediation Liabilities

We record liabilities for estimated environmental remediation obligations when we assess that a loss is probable and the amount of the loss can be reasonably estimated. At December 31, 2009, we have an accrual for estimated environmental remediation obligations of $6.6 million. This remediation accrual is revised, and our associated income is affected, during periods in which new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. We base liabilities for environmental remediation upon our assumptions and estimates regarding what remediation work and post-remediation monitoring will be required and the costs of those efforts, which we develop from information obtained from outside consultants and from discussions with the applicable governmental authorities. As new developments occur or more information becomes available, it is possible that our assumptions and estimates in these matters will change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarter or annual period. (Please read Environmental and Note 16, Commitments and Contingencies, in our Notes to Consolidated Financial Statements.)

Results of Operations

Consolidated Overview

The following table and discussion summarize our consolidated results of operations for the three years ended December 31, 2009 and do not reflect the consummation of the Dropdown. The results of operations by segment are discussed in further detail following this consolidated overview discussion and relate to the segment tables in Note 17, Segment Disclosures, in our Notes to Consolidated Financial Statements.

	2009	% Change from 2008(1)	2008	% Change from 2007(1)	2007
		(Dollars in thousands)			
Revenues	$ 470,189	(26)%	$ 637,060	+11%	$ 572,817
Costs and expenses:					
Product cost and shrink replacement	103,225	+50%	206,078	(13)%	181,698
Operating and maintenance expense	163,064	+12%	185,901	(15)%	162,343
Depreciation, amortization and accretion	44,887		45,029	+3%	46,492
General and administrative expense	51,245	(9)%	47,059	(3)%	45,628
Taxes other than income	10,149	(7)%	9,508	+1%	9,624
Other (income) expense net	(4,133)	+17%	(3,523)	NM	12,095
Total costs and expenses	368,437	+25%	490,052	(7)%	457,880
Operating income	101,752	(31)%	147,008	+28%	114,937
Equity earnings Wamsutter	84,052	(5)%	88,538	+16%	76,212
Discovery investment income	27,243	+22%	22,357	(22)%	28,842
Interest expense	(60,679)	+10%	(67,220)	(15)%	(58,348)
Interest income	99	(86)%	706	(76)%	2,988
Net income	$ 152,467	(20)%	$ 191,389	+16%	$ 164,631

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

2009 vs. 2008

Revenues decreased $166.9 million, or 26%, due primarily to lower product sales in our West segment resulting from significantly lower average NGL sales prices, lower sales of NGLs on behalf of third-party producers and lower condensate and LNG sales.

Product cost and shrink replacement decreased $102.9 million, or 50%, due primarily to lower product cost and shrink replacement in our West segment related primarily to decreased purchases of NGLs from third-party producers and lower average natural gas prices.

Operating and maintenance expense decreased $22.8 million, or 12%, due primarily to lower system and imbalance losses in our West segment and lower fractionation fuel costs resulting from sharply lower natural gas prices in our NGL Services segment.

General and administrative expense increased $4.2 million, or 9%, due primarily to higher charges allocated by Williams to us for various administrative expenses and certain expenses related to the Dropdown.

Operating income decreased $45.3 million, or 31%, due primarily to substantially lower average per-unit NGL sales margins, lower sales margins for condensate and LNG and lower involuntary conversion gains in our West segment. These decreases were partially offset by lower operating and maintenance expenses in our West segment and the absence of a 2008 impairment of our Carbonate Trend pipeline.

Equity earnings from Wamsutter decreased $4.5 million, or 5%, due primarily to lower per-unit NGL sales margins, partially offset by a higher percentage allocation of Wamsutter s net income in 2009. As described in Note 7, Equity Investments, of our Notes to Consolidated Financial Statements, Wamsutter s net income was allocated based upon the allocation, distribution, and liquidation provisions of its limited liability company (LLC) agreement. For the year ended December 31, 2008, this allocation resulted in a $15.2 million allocation of Wamsutter s net income to the Class C interest not owned by us.

Discovery investment income increased $4.9 million, or 22%, due primarily to higher gathering and transportation revenue, lower operating and maintenance expense and higher hurricane-related proceeds received under our Discovery business interruption policy. These increases were largely offset by lower NGL sales margins resulting from sharply lower average per-unit margins on higher volumes of NGL equity sales and an unfavorable change in other (income) expense, net.

Interest expense decreased $6.5 million, or 10%, due primarily to the lower interest rate on our $250.0 million floating-rate term loan.

2008 vs. 2007

Revenues increased $64.2 million, or 11%, due primarily to higher product sales in our West segment and higher fractionation, product sales and storage revenues in our NGL Services segment.

Product cost and shrink replacement increased $24.4 million, or 13%, due primarily to higher cost of product sales in both our West and NGL Services segments and higher average natural gas prices for shrink replacement in our West segment.

Operating and maintenance expense increased $23.6 million, or 15%, due primarily to higher repairs and maintenance, materials and supplies and system losses in our West segment.

Other (income) expense net in 2008 reflects an $11.6 million involuntary conversion gain related to the November 2007 Ignacio plant fire. Other (income) expense net for 2008 and 2007 includes a $6.2 million and $10.4 million impairment, respectively, of our Carbonate Trend pipeline in our Gulf segment.

Operating income increased $32.1 million, or 28%, due primarily to higher per-unit NGL margins on slightly lower sales volumes, an $11.6 million involuntary conversion gain in 2008, higher other fee revenue and higher condensate sales margins in our West segment, combined with higher fractionation and storage revenues in our NGL Services segment and a $4.2 million lower impairment loss on the Carbonate Trend pipeline in our Gulf segment. Partially offsetting these favorable variances were lower fee-based gathering revenues and higher operating and maintenance expenses in our West segment.

Equity earnings Wamsutter increased $12.3 million, or 16%, due primarily to higher average per-unit NGL margins on increased NGL sales volumes.

Discovery investment income decreased $6.5 million, or 22%, due primarily to lower equity earnings caused by Hurricanes Ike and Gustav, partially offset by hurricane-related receipts under our Discovery-related business interruption policy.

Interest expense increased $8.9 million, or 15%, due primarily to interest on our $250.0 million term loan issued in December 2007 to finance a portion of our acquisition of ownership interests in Wamsutter.

Interest income decreased $2.3 million, or 76%, due primarily to significantly lower daily interest rates on higher fourth-quarter 2008 cash balances compared to fourth quarter 2007.

Results of operations Gathering and Processing West

The Gathering and Processing West segment includes our Four Corners natural gas gathering, processing and treating assets and our ownership interest in Wamsutter.

	2009	2008	2007
		(In thousands)	
Segment revenues	$ 406,598	$ 560,138	$ 513,787
Costs and expenses:			
Product cost and shrink replacement	93,387	189,192	170,434
Operating and maintenance expense	136,509	156,713	135,782
Depreciation, amortization and accretion	41,326	41,215	41,523
General and administrative expense direct	9,008	8,333	7,790
Taxes other than income	9,268	8,770	8,869
Other (income) expense net	(4,453)	(9,709)	1,698
Total costs and expenses	285,045	394,514	366,096
Segment operating income	121,553	165,624	147,691
Equity earnings Wamsutter	84,052	88,538	76,212
Segment profit	$ 205,605	$ 254,162	$ 223,903

Four Corners

2009 vs. 2008

Four Corners segment operating income decreased $44.1 million, or 27%, due primarily to $49.1 million lower NGL sales margins resulting primarily from a 41% decrease in average per-unit NGL margins, $5.4 million lower condensate and LNG sales margins and $7.6 million lower involuntary conversion gains related to the 2007 Ignacio plant fire. These decreases were partially offset by $20.2 million lower operating and maintenance expense. A more detailed analysis of the components of the change in segment operating income is below.

Revenues decreased $153.5 million, or 27%, due primarily to the following lower product sales:

$91.6 million related to a 47% decrease in average NGL sales prices realized on sales of NGLs which we received under keep-whole and percent-of-liquids processing contracts (NGL equity sales). This decrease resulted from general decreases in market prices for these commodities between the two periods.

$47.5 million lower sales of NGLs on behalf of third-party producers. Under these arrangements, we purchase the NGLs from the third-party producers and sell them to an affiliate. This decrease was related to general decreases in market prices and lower volumes and is offset by lower associated product costs of $47.2 million discussed below.

$13.5 million lower condensate and LNG sales resulting from decreased average per-unit prices and lower LNG volumes.

Product cost and shrink replacement decreased $95.8 million, or 51%, due primarily to:

$47.2 million decrease from third-party producers who have us purchase their NGLs, which was offset by the corresponding decrease in product sales discussed above.

$37.7 million decrease from 54% lower average natural gas prices.

$8.1 million decrease in condensate and LNG-related product cost.

Operating and maintenance expense decreased $20.2 million, or 13%, due primarily to $20.6 million lower system and imbalance volume losses and $7.7 million lower unreimbursed gathering fuel costs. Both imbalance losses and unreimbursed gathering fuel costs were favorably impacted by lower natural gas costs. While our system losses are generally an unpredictable component of our operating costs, they can be higher during periods of prolonged, severe winter weather, such as those we experienced during January and February of 2008. Additionally, operational inefficiencies caused by the fire at the Ignacio plant impacted our system losses in 2008. These decreases in expense were partially offset by higher right-of-way costs, increased labor costs and 2009 Ignacio pipeline rupture repair costs.

Other income decreased $5.3 million, or 54%, due primarily to $7.6 million lower involuntary conversion gains in 2009 related to the November 2007 Ignacio plant fire.

2008 vs. 2007

Segment operating income increased $17.9 million, or 12%, due primarily to:

- $20.0 million higher NGL margins resulting primarily from higher per-unit NGL margins. Record NGL margins experienced during the first three quarters were impacted unfavorably in the fourth-quarter 2008 when NGL sales prices declined significantly.

- $11.6 million of 2008 involuntary conversion gains.

- $9.0 million higher other revenues.

Partially offsetting these increases were $20.9 million higher operating and maintenance expenses and $7.1 million lower fee-based gathering revenues.

Revenues increased $46.4 million, or 9%, due primarily to $43.0 million higher product sales revenues and $9.0 million improved other revenue, slightly offset by $7.1 million lower gathering revenues. The significant components of the revenue fluctuations are addressed more fully below.

Product sales revenues increased $43.0 million due primarily to:

- $35.3 million from 22% higher average per-unit NGL sales prices realized on NGL volumes we received under keep-whole and percent-of-liquids processing contracts. NGL sales prices were sharply higher in the first three quarters of 2008 compared to 2007; however, NGL sales prices declined significantly in the fourth quarter of 2008.

- $6.6 million higher sales of NGLs on behalf of third-party producers. Under these arrangements, we purchase NGLs from the third-party producers and sell them to an affiliate. This increase is offset by higher associated product costs of $6.9 million discussed below.

- $4.6 million higher condensate sales resulting primarily from higher prices.

These increases in product sales revenues were slightly offset by a $4.4 million impact of 3% lower NGL sales volumes.

Other revenue improved $9.0 million due primarily to a $4.4 million fourth-quarter 2008 insurance reimbursement for lost profits under our business interruption insurance related to the November 2007 Ignacio plant fire and the absence of a $3.5 million third-quarter 2007 unfavorable revenue recognition correction for electronic flow measurement fees.

Fee-based gathering revenues decreased $7.1 million, or 4%, due primarily to a $7.6 million decline in revenue from lower gathering volumes. This resulted from the prolonged, severe weather during early 2008 which inhibited both our and our customers abilities to access facilities, connect new wells and maintain production. The 2007 volumes were reduced by the fire at the Ignacio gas processing plant in late November 2007.

Product cost and shrink replacement increased $18.8 million, or 11%, due primarily to $10.7 million from higher average natural gas prices for shrink replacement and $6.9 million higher NGL purchases from third-party producers who elected to have us purchase their NGLs (offset by the corresponding increase in product sales discussed above).

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Operating and maintenance expense increased $20.9 million, or 15%, due primarily to $12.0 million higher system and imbalance losses and $9.1 million higher repairs and maintenance and materials and supplies expense. During 2008 our volumetric system loss, as a percentage of total volume received, was significantly higher than in 2007. While our system losses are generally an unpredictable component of our operating costs, they can be higher during periods of prolonged, severe weather, such as those we experienced during early 2008. Additionally, operating inefficiencies caused by the fire at Ignacio plant unfavorably impacted our system losses.

Other (income) expense net improved $11.4 million due primarily to an $11.6 million involuntary conversion gain recognized in 2008 related to the November 2007 Ignacio plant fire.

Wamsutter

Wamsutter was accounted for using the equity method of accounting. As such, our interest in Wamsutter s net operating results is reflected as equity earnings in our Consolidated Statements of Income. The following discussion addresses in greater detail the results of operations for 100% of Wamsutter. Please read Note 7, Equity Investments, of our Notes to Consolidated Financial Statements for discussion of how Wamsutter allocated its net income between its member owners including us.

	Years Ended December 31,		
	2009	**2008**	**2007**
		(In thousands)	
Revenues	$ 195,887	$ 239,534	$ 175,309
Costs and expenses, including interest:			
Product cost and shrink replacement	52,300	78,809	46,039
Operating and maintenance expense	20,527	20,973	18,257
Depreciation and accretion	22,235	21,182	18,424
General and administrative expense	15,207	13,507	12,623
Taxes other than income	2,014	1,868	1,637
Other (income) expense, net	(448)	(569)	944
Total costs and expenses	111,835	135,770	97,924
Net income	$ 84,052	$ 103,764	$ 77,385
Williams Partners interest	$ 84,052	$ 88,538	$ 76,212

2009 vs. 2008

Wamsutter s net income decreased $19.7 million, or 19%, due primarily to $23.9 million lower NGL sales margins resulting primarily from sharply decreased per-unit NGL margins.

As described in Note 7, Equity Investments, of our Notes to Consolidated Financial Statements, Wamsutter s net income was allocated based upon the allocation, distribution, and liquidation provisions of its limited liability company agreement. Net income for 2009 was allocated as presented in the table below:

Wamsutter Net Income Allocation 2009	**Wamsutter Net Income (Millions)**
Net income for December 1, 2008 November 30, 2009	$ 77.3
Less net income allocated for transition support contribution	(9.7)
Less net income for December 2008	(1.0)

Net income for 2009 allocation	$ 66.6

	Class A	Our Share Class C	WPZ Total (Millions)	Other Class C	Wamsutter Net Income
Allocation up to $70 million (excluding December 2008 allocation)	$ 66.6	$	$ 66.6	$	$ 66.6
Income allocation for transition support contribution	9.7		9.7		9.7
December 2009 income allocation	7.8		7.8		7.8
Totals	$ 84.1	$	$ 84.1	$	$ 84.1

Revenues decreased $43.7 million, or 18%, due primarily to $59.6 million lower product sales, partially offset by $10.9 million higher fee-based gathering and processing revenue.

Product sales revenues decreased $59.6 million, or 38%, due primarily to:

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$67.6 million related to a 41% decrease in average NGL sales prices realized on sales of NGLs which Wamsutter received under keep-whole processing contracts. This decrease resulted from general decreases in market prices for these commodities between the two periods.

$3.1 million of favorable adjustments in the first quarter of 2008 related to the margin-sharing provisions of one of Wamsutter s significant contracts.

These product sales decreases were partially offset by $9.1 million higher sales of NGLs on behalf of third-party producers. This increase is offset by higher associated product costs discussed below.

Gathering and processing fee-based revenues increased $10.9 million, or 16%, due to a 7% increase in average volumes and an 8% increase in the average fee received for these services. The increase in average volumes was due primarily to new wells connected in 2009 and production problems in 2008 caused by severe winter weather conditions. The average fee increased as a result of negotiated increases in gathering fees and fixed annual percentage or inflation-sensitive contractual escalation clauses.

Product cost and shrink replacement decreased $26.5 million, or 34%, due primarily to a $39 million decrease from 49% lower average natural gas prices, partially offset by $9.1 million higher product cost related to sales of NGLs on behalf of third-party producers as discussed above.

General and administrative expense increased $1.7 million due primarily to higher charges allocated by Williams to us for various administrative support functions.

Depreciation and accretion expense increased $1.1 million due primarily to new assets placed into service.

2008 vs. 2007

Net income increased $26.4 million, or 34%, due primarily to $27.9 million higher NGL margin resulting from increased per-unit margins on higher NGL sales volumes.

As described in Note 7, Equity Investments, of our Notes to Consolidated Financial Statements, Wamsutter s net income is allocated based upon the allocation, distribution, and liquidation provisions of its limited liability company agreement. Net income for 2008 was allocated as presented in the table below:

Wamsutter Net Income Allocation 2008	**Wamsutter Net Income (Millions)**
Net income for December 1, 2007 November 30, 2008	$ 110.1
Less net income allocated for transition support contribution	(7.6)
Less net income for December 2007	(7.4)
Net income for 2008 allocation	$ 95.1

	Our Share Class A	**Our Share Class C**	**WPZ Total (Millions)**	**Other Class C**	**Wamsutter Net Income**
Allocation up to $70 million (excluding December 2007 allocation)	$ 62.6	$	$ 62.6	$	$ 62.6
Allocation of net income over $70 million	2.1	15.2	17.3	15.2	32.5
Income allocation for transition support contribution	7.6		7.6		7.6
December 2008 income allocation	1.0		1.0		1.0
Totals	$ 73.3	$ 15.2	$ 88.5	$ 15.2	$ 103.7

Revenues increased $64.2 million, or 37%, due primarily to $61.6 million higher sales of NGLs which Wamsutter received under keep-whole processing contracts. This increase reflects $39.5 million related to higher average sales prices and $22.1 million related to 23% higher sales volumes. This volumetric increase was due primarily to a lower volume of gas delivered by Wamsutter s fee-based customers in the first quarter of 2008 due to inclement weather which allowed Wamsutter to process additional keep-whole gas at the Echo Springs plant. Additionally, Wamsutter benefited from the ability to process additional keep-whole gas at Colorado Interstate Gas Company s Rawlins natural gas processing plant.

Product cost and shrink replacement increased $32.8 million, or 71%, due primarily to a $24.2 million increase from higher average natural gas prices and $9.5 million from higher volumetric shrink requirements due to higher volumes processed under Wamsutter s keep-whole processing contracts. Gas prices in 2007 were impacted by very low local natural gas costs compared with other natural gas markets.

Operating and maintenance expense increased $2.7 million, or 15%, due primarily to higher gathering fuel, third-party processing, and material and supply costs, substantially offset by $5.0 million higher system gains.

Depreciation and accretion increased $2.8 million, or 15%, due primarily to new assets placed into service.

Results of operations Gathering and Processing Gulf

The Gulf segment includes the Carbonate Trend gathering pipeline and our 60% ownership interest in Discovery.

	2009	2008	2007
		(In thousands)	
Segment revenues	$ 1,708	$ 2,096	$ 2,119
Costs and expenses:			
Operating and maintenance expense	1,459	1,668	1,875
Depreciation, amortization and accretion	170	751	1,249
Other expense, net	325	6,187	10,406
Total costs and expenses	1,954	8,606	13,530
Segment operating loss	(246)	(6,510)	(11,411)
Discovery investment income	27,243	22,357	28,842
Segment profit	$ 26,997	$ 15,847	$ 17,431

Carbonate Trend

2009 vs. 2008

Segment operating loss improved significantly as a result of the lack of asset impairment expense in 2009. The Carbonate Trend pipeline was fully impaired in 2008.

2008 vs. 2007

Segment operating loss improved $4.9 million because the impairment loss recognized on the Carbonate Trend pipeline was $4.2 million lower in 2008 than in 2007. (Please read Note 8, Other (Income) Expense, of our Notes to Consolidated Financial Statements.)

Discovery

Discovery is accounted for using the equity method of accounting. As such, our interest in Discovery s net operating results is reflected as equity earnings in our Consolidated Statements of Income. The following discussion addresses in greater detail the results of operations for 100% of Discovery.

	2009	2008	2007
		(In thousands)	
Revenues	$ 161,019	$ 241,248	$ 260,672
Costs and expenses, including interest:			
Product cost and shrink replacement	72,506	146,998	155,704
Operating and maintenance expense	23,445	36,670	28,988
Depreciation and accretion	18,751	21,324	25,952
General and administrative expense	6,000	4,500	2,280
Interest income	(31)	(650)	(1,799)
Other (income) expense, net	3,441	(1,994)	1,476
Total costs and expenses	124,112	206,848	212,601
Net income	$ 36,907	$ 34,400	$ 48,071
Williams Partners interest equity earnings	$ 23,023	$ 20,641	$ 28,842
Business interruption proceeds	4,220	1,716	
Discovery investment income	$ 27,243	$ 22,357	$ 28,842

2009 vs. 2008

Net income increased $2.5 million, or 7%, due primarily to $12.4 million higher gathering and transportation revenue, $13.2 million lower operating and maintenance expense and $2.6 million lower depreciation and accretion expense. These increases were largely offset by $18.5 million lower NGL sales margins resulting from sharply lower average per-unit margins on higher volumes of NGL equity sales and a $5.4 million unfavorable change in other (income) expense, net. A more detailed analysis of the components of the change in net income is below.

Revenues decreased $80.2 million, or 33%, due primarily to $94.2 million lower product sales, partially offset by $12.4 million higher gathering and transportation revenue resulting primarily from higher rates and higher volumes. The 2009 volumes were higher due primarily to the recovery from the impact of the 2008 hurricanes and the receipt of volumes from the Tahiti spar beginning in the second quarter of 2009.

The lower product sales are due primarily to:

- $65.7 million related to 46% lower average per-unit prices on NGL equity sales as a result of general decreases in market commodity prices.

- $40.3 million lower product sales resulting from lower NGL sales volumes sold on behalf of third-party producers.

These decreases in product sales are partially offset by $13.0 million higher product sales from a 10% increase in NGL equity sales volumes.

Product cost and shrink replacement decreased $74.5 million, or 51%, due primarily to a decrease in the related NGL sales on behalf of third-party producers discussed above, combined with lower prices for natural gas purchased for shrink replacement.

Operating and maintenance expense decreased $13.2 million, or 36%, due primarily to the absence of 2008 hurricane costs that were unrecoverable from insurance, combined with lower 2009 fuel costs resulting from lower prices for natural gas and favorable system gains.

Depreciation and accretion decreased $2.6 million, or 12%, due primarily to a 2008 change in the estimated remaining useful lives of the Larose processing plant and the regulated pipeline and gathering system, partially offset by the impact of the Tahiti assets placed into service in 2009.

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Other (income) expense, net changed unfavorably by $5.4 million due to the absence of a 2008 favorable adjustment of $3.5 million for a FERC settlement, combined with higher property taxes in 2009 following the end of a tax abatement period.

2008 vs. 2007

Net income decreased $13.7 million, or 28%, due primarily to $8.0 million lower fee-based gathering, processing, fractionation and transportation revenue resulting from third and fourth quarter lost revenues in the aftermath of Hurricanes Ike and Gustav, $7.7 million higher operating and maintenance expense and $5.4 million lower NGL sales margins, slightly offset by $4.6 million lower depreciation and accretion expense.

Revenues decreased $19.4 million, or 7%, due primarily to $13.1 million lower product sales described below and $8.0 million lower fee-based gathering, processing, fractionation and transportation revenue resulting from lost revenues in the aftermath of Hurricanes Ike and Gustav. The lower product sales revenues are due primarily to:

$21.5 million lower sales of NGLs on behalf of third-party producers as a result of the hurricanes which is offset by lower associated product costs of $21.5 million discussed below.

$16.8 million decrease from lower NGL volumes processed under keep-whole and percent-of-liquids arrangements, including lower NGL volumes following Hurricanes Ike and Gustav.

These decreases were partially offset by $26.3 million higher product sales from higher average NGL sales prices realized on sales of NGLs which Discovery received under certain processing contracts.

Product cost and shrink replacement decreased $8.7 million, or 6%, due primarily to a $21.5 million decrease in product purchased from third-party producers as a result of the impact of the hurricanes, partially offset by $15.9 million from higher average natural gas prices.

Operating and maintenance expense increased $7.7 million, or 27%, due primarily to 2008 hurricane survey and repair costs on the gathering system damaged by Hurricane Ike that are not recoverable from insurance.

Depreciation and accretion decreased $4.6 million, or 18%, due primarily to a change in the estimated remaining useful lives of the Larose processing plant and the regulated pipeline and gathering system.

General and administrative expense increased $2.2 million, or 97%, due to an increase in Discovery s management fee charged by Williams.

Other (income) expense, net improved $3.5 million due to a recently approved FERC settlement filing that allowed the 2008 reversal of a $3.5 million reserve for system fuel and lost and unaccounted for gas related to 1998 through 2003.

Results of operations NGL Services

The NGL Services segment includes our three NGL storage facilities near Conway, Kansas and our 50% undivided interest in the Conway fractionator.

	2009	2008	2007
		(In thousands)	
Segment revenues	$ 61,883	$ 74,826	$ 56,911
Costs and expenses:			
Product cost	9,838	16,886	11,264
Operating and maintenance expense	25,096	27,520	24,686
Depreciation and accretion	3,391	3,063	3,720
General and administrative expense direct	3,245	2,582	2,190
Other expense, net	876	737	746
Total costs and expenses	42,446	50,788	42,606
Segment profit	$ 19,437	$ 24,038	$ 14,305

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2009 vs. 2008

NGL Services segment profit declined $4.6 million due primarily to higher environmental-related operating costs. A more detailed analysis of the components of segment profit is below.

Segment revenues decreased $12.9 million, or 17%, due primarily to lower product sales, fractionation and other fee revenues, partially offset by higher storage revenues. The significant components of the revenue fluctuations are addressed more fully below.

Product sales decreased $6.3 million due to a 23% decrease in average price per barrel. The decrease in product sales revenue was more than offset by the related decrease in product cost discussed below.

Fractionation revenues decreased $6.9 million due primarily to a 41% decrease in average fractionation price per barrel. The decrease in the average fractionation price per barrel results from the decline in natural gas prices.

Other fee revenues decreased $1.6 million due primarily to a decrease in customer fees to upgrade butane.

Storage revenues increased $1.8 million, or 6%, due primarily to higher overstorage revenue.

Product cost decreased $7.0 million, or 42%, due to the lower product prices discussed above.

Operating and maintenance expense decreased $2.4 million, or 9%, due primarily to $6.4 million lower fractionation fuel costs resulting from sharply lower natural gas prices, largely offset by higher environmental-related operating costs.

2008 vs. 2007

NGL Services segment profit increased $9.7 million, or 68%, due primarily to higher fractionation and storage revenues, partially offset by higher operating and maintenance expenses.

Segment revenues increased $17.9 million, or 31%, due primarily to higher fractionation, product sales and storage revenues. The significant components of the revenue fluctuations are addressed more fully below.

Fractionation revenues increased $7.8 million due primarily to a 59% higher average fractionation rate and 6% higher volumes. The higher average rate is due primarily to the December 2007 expiration of a fractionation contract with a cap on the per-unit fee, which limited our ability to pass through increases in fractionation fuel expense to this customer.

Product sales increased $5.4 million due to higher sales volumes and an increase in average product sales prices. This increase was slightly offset by the related increase in product cost discussed below.

Storage revenues increased $3.4 million due primarily to higher storage revenues from new storage leases.

Product cost increased $5.6 million, or 50%, due to the higher product sales volumes and prices discussed above.

Operating and maintenance expense increased $2.8 million, or 11%, due primarily to $4.0 million unfavorable storage product losses, $2.5 million higher maintenance costs and $1.3 million higher fractionation fuel costs. These increases were partially offset by a $2.9 million product imbalance adjustment in 2008 and $2.0 million of fractionation blending gains.

Performance Outlook for 2010

In the first quarter of 2010, we expect to record approximately $10 million of estimated general and administrative expenses related to the Dropdown. Additionally, beginning in 2010 as a result of the Dropdown, our operations will be divided into two business segments: Gas Pipeline and Midstream Gas & Liquids. All of the operations we conducted prior to the Dropdown are reported within the Midstream Gas & Liquids segment. Set forth below is information regarding our performance expectations for 2010 for each of these business segments.

Gas Pipeline

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

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

Outlook for 2010

In addition to the various in-progress expansion projects discussed in *Capital Expenditures* below, we have several other proposed projects to meet customer demands. Subject to regulatory approvals, construction of some of the other projects could begin as early as 2010.

Midstream Gas & Liquids

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

Outlook for 2010

The following factors could impact our business in 2010.

Commodity price changes

NGL, crude and natural gas prices are highly volatile and difficult to predict. However, we expect per-unit NGL margins in 2010 to be higher than our average per-unit margins in 2009 and our rolling five-year average per-unit NGL margins. NGL price changes have historically tracked somewhat with changes in the price of crude oil. Margins in our NGL business are highly dependent upon continued demand within the global economy. Although forecasted domestic and global demand for polyethylene, or plastics, has been impacted by the weakness in the global economy, NGL products are currently the preferred feedstock for ethylene and propylene production, which are the building blocks of polyethylene. Propylene and ethylene production processes have increasingly shifted from the more expensive crude-based feedstocks to NGL-based feedstocks. Bolstered by abundant long-term natural gas supplies, we expect to benefit from these dynamics in the broader global petrochemical markets. As natural gas pipeline transportation capacity increases in the Rocky Mountain area, we anticipate that historically favorable natural gas price differentials will decline.

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, we have entered into NGL swap agreements to fix the prices of a small portion of our anticipated NGL sales for 2010. In addition, we have entered into financial contracts to fix the price of a portion of our shrink gas requirements for 2010.

Gathering, processing and NGL sales volumes

The growth of natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities. Our customers are generally large producers, and we have not experienced and do not anticipate an overall significant decline in volumes due to reduced drilling activity.

In the West, we expect higher fee revenues, NGL volumes, depreciation expense and operating expenses in 2010 compared to 2009 as our Willow Creek facility moves into a full year of operation and our expansion at Echo Springs is completed late in 2010.

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- We expect fee revenues, NGL volumes, depreciation expense, and operating expenses in our offshore Gulf Coast region to increase from 2009 levels as our new Perdido Norte expansion begins start-up operations in the first quarter of 2010. Increases from our Perdido Norte expansion are expected to be partially offset by lower NGL volumes in other Gulf Coast areas due to expected changes in gas processing contracts, as described below, and natural declines.

- Certain of our gas processing contracts contain provisions that allow customers to periodically elect processing services on either a fee basis, keep-whole, or percent-of-liquids basis. If customers switch from keep-whole to fee-based processing, this would reduce our NGL equity sales volumes.

Management s Discussion and Analysis of Financial Condition and Liquidity

Overview

As previously discussed in Recent Developments The Dropdown , on February 17, 2010 Williams contributed to us its ownership interests in the entities that make up Williams Gas Pipeline and Midstream Gas & Liquids business segments (including its limited and general partner interests in WMZ, but excluding its Canadian, Venezuelan and olefins operations, and a 25.5% interest in Gulfstream), to the extent not already owned by us. This contribution was in exchange for the aggregate consideration previously described.

The Dropdown significantly increased the scale, proportion of fee-based revenues and diversity of our businesses and impacted our financial condition and liquidity as illustrated by the following points:

- Increased our total assets from $1.3 billion to approximately $12 billion and our total long-term debt from $1.0 billion to $6.5 billion.

- Increased the number of limited partner units outstanding from 53 million to 256 million.

- Increased our cash flows from operations from $199 million in 2009 to a forecasted range of $1.2 billion to $1.8 billion for 2010.

- Increased our expansion capital expenditures from $11 million in 2009 to a forecasted range of $660 million to $870 million for 2010.

- Increased our maintenance capital expenditures from $19 million in 2009 to a forecasted range of $290 million to $330 million for 2010.

- Increased our credit ratings to investment grade.

- Terminated our previous $450 million senior unsecured revolving credit facility and established a new $1.75 billion senior unsecured revolving credit facility.

Outlook

For 2010, we expect operating results and cash flows to improve from 2009 levels due to the impact of expected higher energy commodity prices and the start-up of certain expansion capital projects. However, as previously mentioned, energy commodity prices are volatile and difficult to predict. Although our cash flows are impacted by fluctuations in energy commodity prices, that impact is somewhat mitigated by certain of our cash flow streams that are substantially insulated from unfavorable commodity price movements, as follows:

- Firm demand and capacity reservation transportation revenues under long-term contracts at Gas Pipeline;

- Fee-based revenues from certain gathering and processing services at Midstream;

- Hedged NGL sales and natural gas purchases for a portion of activities at Midstream.

We believe we have, or have access to, the financial resources and liquidity necessary to meet our requirements for working capital, capital and investment expenditures, and debt service payments while maintaining a sufficient level of liquidity. In particular, we note the following expectations for 2010:

- We expect to increase our per-unit quarterly distribution from $0.6350 to $0.6575 beginning with the distribution with respect to first quarter of 2010.
- We expect to fund capital and investment expenditures, debt service payments, distributions to unitholders and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, cash proceeds from common unit and/or long-term debt issuances and utilization of our revolving credit facilities as needed.

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 2010. Our internal and external sources of liquidity include:

- Cash and cash equivalents on hand;
- Cash generated from operations, including cash distributions from our equity-method investees;
- Cash proceeds from offerings of our common units and/or long-term debt;
- Capital contributions from Williams pursuant to the omnibus agreement; and
- Use of credit facilities, as needed and available.

We anticipate our more significant uses of cash to be:

- Maintenance and expansion capital expenditures;
- Contributions to our equity-method investees to fund their expansion capital expenditures;
- Interest on our long-term debt; and
- Quarterly distributions to our unitholders and/or general partner.

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

- Lower than expected levels of cash flow from operations.
- Sustained reductions in energy commodity prices from expected 2010 levels.
- Exposure associated with our efforts to resolve regulatory and litigation issues (Please read Note 16, Commitments and Contingencies, of our Notes to Consolidated Financial Statements).
- Physical damages to facilities, especially damage to offshore facilities by named windstorms for which our aggregate policy limit is $37.5 million in the event of a material loss.

Available Liquidity

	February 18, 2010	
	(In millions)	
Cash and cash equivalents	$	117
Available capacity under our $1.75 billion three-year senior unsecured credit facility (expires February 15, 2013)		1,500

$	1,617

Shelf Registration

On October 28, 2009, we filed a shelf registration statement as a well-known seasoned issuer that allows us to issue an unlimited amount of registered debt and limited partnership unit securities.

Distributions from Equity Method Investees

Our equity method investees organizational documents require distribution of their available cash to their members on a quarterly basis. In each case, available cash is reduced, in part, by reserves appropriate for operating their respective businesses. Our more significant equity method investees include: Aux Sable Liquid Products, Discovery, Gulfstream and Laurel Mountain.

Omnibus Agreement with Williams

In connection with the closing of the Dropdown, we entered into an omnibus agreement with Williams. Pursuant to this omnibus agreement, Williams is obligated to indemnify us from and against or reimburse us for (i) amounts incurred by us or our subsidiaries for repair or abandonment costs for damages to certain facilities caused by Hurricane Ike, up to a maximum of $10 million, (ii) maintenance capital expenditure amounts incurred by us or our subsidiaries in respect of certain U.S. Department of Transportation projects, up to a maximum aggregate amount of $50 million, and (iii) an amount based on the amortization over time of deferred revenue amounts that relate to cash payments received prior to the closing of the Dropdown for services to be rendered by us in the future at the Devils Tower floating production platform located in Mississippi Canyon Block 773. In addition, we will be obligated to pay to Williams the net proceeds of certain sales of natural gas recovered from the Hester storage field pursuant to the FERC order dated March 7, 2008, approving a settlement agreement in Docket No. RP06-569.

Credit Facilities

At December 31, 2009, we had a $450 million senior unsecured credit agreement (Credit Agreement) with Citibank, N.A. as administrative agent, comprised of a $200 million revolving credit facility available for borrowings and letters of credit and a $250 million term loan. In connection with the Dropdown, we terminated the Credit Agreement and entered into a new $1.75 billion three-year senior unsecured revolving credit facility (New Credit Facility) with Transco and Northwest Pipeline, as co-borrowers, and Citibank, N.A. as the administrative agent, and certain other lenders named therein. The full amount of the New Credit Facility is available to us, to the extent not otherwise utilized by Transco and Northwest Pipeline, and may be increased by up to an additional $250 million. Transco and Northwest Pipeline are each able to borrow up to $400 million under the New Credit Facility to the extent not otherwise utilized by us. At closing, we borrowed $250 million under the New Credit Facility to repay the $250 million term loan outstanding under the Credit Agreement.

Interest on borrowings under the New Credit Facility is payable at rates per annum equal to, at the option of the borrower: (1) a fluctuating base rate equal to Citibank, N.A. s adjusted base rate plus the applicable margin or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. The adjusted base rate will be the highest of (i) the federal funds rate plus 0.5%, (ii) Citibank N.A. s publicly announced base rate and (iii) one-month LIBOR plus 1.0%. We pay a commitment fee (currently 0.5%) based on the unused portion of the New Credit Facility. The applicable margin and the commitment fee are determined by reference to a pricing schedule based on a borrower s senior unsecured debt ratings.

The New Credit Facility contains various covenants that limit, among other things, a borrower s and its respective subsidiaries ability to incur indebtedness, grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default and allow any material change in the nature of its business.

In addition, we are required to maintain a ratio of debt to EBITDA (each as defined in the New Credit Facility) of no greater than 5.00 to 1.00 for us and our consolidated subsidiaries. For each of Transco and Northwest Pipeline and their respective consolidated subsidiaries, the ratio of debt to capitalization (defined as net worth plus debt) is not permitted to be greater than 55%. Each of the above ratios will be tested, beginning June 30, 2010, at the end of each fiscal quarter, and the debt to EBITDA ratio will be measured on a rolling four-quarter basis.

The New Credit Facility includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-payment defaults, cross acceleration, bankruptcy and insolvency events, certain unsatisfied judgments and a change of control. If an event of default with respect to a borrower occurs under the New Credit Facility, the lenders will be able to terminate the commitments for all borrowers and accelerate the maturity of the loans of the defaulting borrower under the New Credit Facility and exercise other rights and remedies.

We also had a $20 million revolving credit facility with Williams as the lender. The facility was available exclusively to fund working capital borrowings. This credit facility was terminated in connection with the Dropdown.

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Credit ratings

The table below presents our current credit ratings and outlook on our senior unsecured long-term debt.

Rating Agency	Date of Last Change	Outlook	Senior Unsecured Debt Rating
Standard & Poor s	January 12, 2010	Positive	BBB-
Moody s Investor Service	February 17, 2010	Stable	Baa3
Fitch Ratings	February 2, 2010	Stable	BBB-

The ratings changes noted above reflect the announcement and completion of the Dropdown.

With respect to Moody s, a rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. A Ba rating indicates an obligation that is judged to have speculative elements and is subject to substantial credit risk. The 1 , 2 and 3 modifiers show the relative standing within a major category. A 1 indicates that an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 indicates a ranking at the lower end of the category.

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

With respect to Fitch, a rating of BBB or above indicates an investment grade rating. A rating below BBB is considered speculative grade. A BB rating from Fitch indicates that there is a possibility of credit risk developing, particularly as the result of adverse economic change over time; however, business or financial alternatives may be available to allow financial commitments to be met. Fitch may add a + or a - sign to show the obligor s relative standing within a major rating category.

Credit rating agencies perform independent analyses when assigning credit ratings. No assurance can be given that the credit rating agencies will assign us investment grade ratings even if we meet or exceed their current criteria for investment grade ratios.

Capital Expenditures

Each of our businesses is capital-intensive, requiring investment to upgrade or enhance existing operations and comply with safety and environmental regulations. The capital requirements of these businesses consist primarily of:

Maintenance capital expenditures, which are generally not discretionary, include capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives, include certain well connection expenditures and expenditures which are mandatory and/or essential for maintaining the reliability of our operations; and

Expansion capital expenditures, which are generally more discretionary than maintenance capital expenditures, include expenditures to acquire additional assets to grow our business, to expand and upgrade plant or pipeline capacity and to construct new plants, pipelines and storage facilities and well connection expenditures which are not classified as maintenance expenditures.

The following table provides summary information related to our expected capital expenditures for 2010 (in millions):

Segment	Maintenance Low	Maintenance Midpoint	Maintenance High	Expansion Low	Expansion Midpoint	Expansion High
Gas Pipeline	$ 210	$ 220	$ 230	$ 340	$ 355	$ 370
Midstream	80	90	100	320	410	500
Total	$ 290	$ 310	$ 330	$ 660	$ 765	$ 870

Expansion capital expenditures include expenditures for the following Gas Pipeline and Midstream projects:

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Gas Pipeline

Mobile Bay South

In May 2009, we received approval from the FERC to construct a compression facility in Alabama allowing transportation service to various southbound delivery points. The cost of the project is estimated to be $37 million. The estimated project in-service date is May 2010 and will increase capacity by 253 Mdt/d.

85 North

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. The cost of the project is estimated to be $241 million. Phase I service is anticipated to begin in July 2010 and will increase capacity by 90 Mdt/d. Phase II service is anticipated to begin in May 2011 and will increase capacity by 218 Mdt/d.

Mobile Bay South II

In November 2009, we filed an application with the FERC to construct additional compression facilities and modifications to existing facilities in Alabama allowing transportation service to various southbound delivery points. The cost of the project is estimated to be $36 million. The estimated project in-service date is May 2011 and will increase capacity by 380 Mdt/d.

Sundance Trail

In November 2009, we received approval from the FERC to construct approximately 16 miles of 30-inch pipeline between our existing compressor stations in Wyoming. The project also includes an upgrade to our existing compressor station and is estimated to cost up to $65 million. The estimated in-service date is November 2010 and will increase capacity by 150 Mdt/d.

Midstream

Perdido Norte

The Perdido Norte project, in the western deepwater of the Gulf of Mexico, includes an expansion of our Markham gas processing facility and oil and gas lines that will expand the scale of our existing infrastructure. Significant milestones have been reached and, considering the progress of our customer s drilling and tie-in construction, we expect this project to begin start-up operations in the first quarter of 2010.

Wamsutter

We expect additional processing and NGL production capacities at our Echo Springs facility and related gathering system expansions in the Wamsutter area of Wyoming to be in service at the end of 2010.

Marcellus Shale

In conjunction with a long-term anchor tenant agreement with a major producer, we will expand our business in the Marcellus Shale with the construction of a 28-mile natural gas gathering pipeline that will gather gas from a third-party s central delivery point in Susquehanna County, Pa. The gas will be delivered to the Gas Pipeline segment s Transco interstate gas pipeline in Luzerne County, Pa. Construction is expected to begin on the 20-inch pipeline in the latter part of 2010 and it is expected to be placed into service during 2011. We will operate the pipeline, which represents our second significant midstream expansion in the Marcellus Shale.

In addition to our initial investment in the Marcellus basin, it is our intent to invest additional capital within our Laurel Mountain joint venture to grow the existing gathering infrastructure in 2010 and beyond.

Cash Distributions to Unitholders

We have paid quarterly distributions to unitholders and our general partner interest after every quarter since our initial public offering on August 23, 2005. We expect to increase our quarterly distribution from $0.6350 to $0.6575 per unit effective with our distribution with respect to the first quarter of 2010. As part of the consideration for the Dropdown, we issued 203 million Class C limited partnership units to Williams, which are identical to our common limited partnership units except that for the first quarter of 2010 they will receive a prorated quarterly distribution since they were not outstanding during the full quarterly period. These Class C units will automatically convert into our common limited partnership units following the record date for the first-quarter 2010 cash distribution.

Results of Operations Cash Flows

The following table summarizes our historical cash flows prior to the Dropdown.

	Years Ended December 31,		
	2009	**2008**	**2007**
	(In millions)		
Net cash provided (used) by:			
Operating activities	$ 199	$ 239	$ 186
Investing activities	(31)	(7)	(393)
Financing activities	(140)	(152)	185
Increase (decrease) in cash and cash equivalents	$ 28	$ 80	$ (22)

Operating Activities

Net cash provided by operating activities decreased $40 million in 2009 as compared to 2008 due primarily to lower operating income excluding non-cash items and lower distributions from Wamsutter.

Net cash provided by operating activities increased $53 million in 2008 as compared to 2007 due primarily to $96 million higher distributions related to our Wamsutter ownership interests purchased in December 2007. This increase was partially offset by an additional $27 million of interest payments related primarily to our $250.0 million term loan issued in December 2007 and timing of interest payments on our $600.0 million senior unsecured notes and $20 million decrease in working capital excluding accrued interest.

Investing Activities

Capital expenditures in 2009, 2008 and 2007 totaled $37 million, $49 million and $47 million. The 2007 results include the purchase of the Wamsutter ownership interests on December 11, 2007 and the additional 20% ownership interest in Discovery on June 28, 2007. Since these ownership interests were purchased from Williams, the transactions were between entities under common control, and have been accounted for at historical cost. Therefore the amount reflected as cash used by investing activities for these purchases represents the historical cost to Williams.

Financing Activities

Net cash used by financing activities in 2009 and 2008 includes distributions to unitholders and our general partner of $144 million and $155 million, respectively.

Net cash provided by financing activities in 2007 includes $266 million of net proceeds from debt and equity issuances related to our acquisition of the Wamsutter ownership interests less the related amounts distributed to Williams in excess of Wamsutter s contributed basis and $87 million of distributions to unitholders and our general partner.

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Contractual Obligations before Completion of the Dropdown

A summary of our contractual obligations as of December 31, 2009, is as follows:

	2010	2011-2012	2013-2014	2015+	Total
			(in millions)		
Long-term debt:					
Principal	$	$ 400	$	$ 600	$ 1,000
Interest	58(a)	98	87	109	352
Capital leases					
Operating leases (b)	14	16	15	105	150
Purchase obligations (c)	32	36	18		86
Other long term obligations					
Total	$ 104	$ 550	$ 120	$ 814	$ 1,588

(a) The assumed interest rate on our $250.0 million term loan is based on the forecasted forward LIBOR plus the applicable margin.

(b) 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 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 2011 and thereafter does not include such variable amounts related to this agreement as the variable amount is not yet determinable.

(c) Includes a five-year service agreement for leased compression and open purchase orders as of December 31, 2009 to be paid in 2010.

Contractual Obligations after Completion of the Dropdown

As a result of the Dropdown and related transactions, our contractual obligations have increased significantly. The following table summarizes our contractual obligations as updated for the impact of the Dropdown and related debt and equity issuances only.

	2010	2011-2012	2013-2014 (in millions)	2015+	Total
Long-term debt:					
Principal	$ 15	$ 784	$ 250	$ 5,452	$ 6,501
Interest	291(a)	724	634	2,982	4,631
Capital leases					
Operating leases (b)	27	40	33	125	225
Purchase obligations	529	449	382	1,535	2,895
Other long term obligations					
Total	$ 862	$ 1,997	$ 1,299	$ 10,094	$ 14,252

(a) The assumed interest rate on our $250.0 million term loan is based on the forecasted forward LIBOR plus the applicable margin.

(b) 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 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 2011 and thereafter does not include such variable amounts related to this agreement as the variable amount is not yet determinable.

Off-Balance Sheet Arrangements

We had no guarantees of off-balance sheet debt to third parties or any other off-balance sheet arrangements at December 31, 2009.

Effects of Inflation

Our operations have benefited from relatively low inflation rates. Following the Dropdown, approximately 66% of our gross property, plant and equipment is at Gas Pipeline. Gas Pipeline is subject to regulation, which limits recovery to historical cost. While amounts in excess of historical cost are not recoverable under current FERC practices, we anticipate being allowed to recover and earn a return based on increased actual cost incurred to replace existing assets. Cost-based regulations, along with competition and other market factors, may limit our ability to recover such increased costs. For Midstream, operating costs are influenced to a greater extent by both competition for specialized services and specific price changes in oil and natural gas and related commodities than by changes in general inflation. Crude, natural gas, and natural gas liquids prices are particularly sensitive to 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 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. 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 $19.3 million, of which $6.6 million are recorded as liabilities on our balance sheet at December 31, 2009 and $12.7 million represents estimates associated with the operations we acquired in the Dropdown. We will seek recovery of approximately $12.6 million of these costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2009, we paid approximately $0.6 million for cleanup and /or remediation and monitoring activities associated with our operations prior to the Dropdown. We expect to pay approximately $3.2 million in 2010 for these activities, including activities associated with the operations acquired in the Dropdown. 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, 2009, certain assessment studies were still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

We are subject to the federal Clean Air Act and to the federal Clean Air Act Amendments of 1990, which require the EPA to issue new regulations. We are also subject to regulation at the state and local level. In September 1998, the EPA promulgated rules designed to mitigate the migration of ground-level ozone in certain states. Revisions to those rules were proposed in January 2010 and may result in additional controls. In March 2004 and June 2004, the EPQ promulgated additional regulation regarding hazardous air pollutants, which may result in additional controls. Capital expenditures necessary to install emission control devices on the Transco gas pipeline system (acquired in the Dropdown) to comply with rules are estimated to be between $5 million and $10 million through 2013. The actual costs incurred will depend on the final implementation plans developed by each state to comply with these regulations. We consider these costs on the Transco system associated with compliance with these environmental laws and regulations to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through its rates.

We have established systems and procedures to meet our reporting obligations under the Mandatory Reporting Rule related to greenhouse gas emissions issued by the EPA in late 2009. Also, certain states in which we have operations have established reporting obligations. We have not incurred significant capital investment to meet the obligations imposed by these new rules. The EPA is developing additional regulations that will expand the scope of the Mandatory Reporting Rule, with particular emphasis on natural gas operations. We are participating directly and through trade associations in developmental aspects of that prospective rulemaking. It is likely that additional rules will be issued in 2010 which may expand our reporting obligations as early as 2011. As those rules are still being developed, at this time we are unable to estimate any capital investment that may be required to comply.

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

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are commodity price risk and interest rate risk.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of NGLs and natural gas, as well as other market factors, such as market volatility and commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets and our long-term energy-related contracts. We manage a portion of the risks associated with these market fluctuations using various derivative contracts. The fair value of derivative contracts is subject to changes in energy-commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. (Please read Note 13, Fair Value Measurements, of our 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% 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. Our derivative contracts are contracts held for nontrading purposes and hedge a portion of our commodity price risk exposure from natural gas liquid sales and natural gas purchases.

The value at risk at December 31, 2009 for Four Corners derivative contracts was $0.1 million. Wamsutter had no derivatives outstanding at December 31, 2009 or 2008 and Four Corners had no derivatives outstanding at December 31, 2008. The Dropdown did not have a significant impact on our derivative portfolio.

All of the derivative contracts included in our value-at-risk calculation are accounted for as cash flow hedges. Any change in the fair value of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Interest Rate Risk before Dropdown

Our interest rate risk exposure is related primarily to our debt portfolio. A majority of our current debt portfolio is comprised of fixed interest rate debt, which mitigates the impact of fluctuations in interest rates. Any borrowings under our credit agreements would be at a variable interest rate and would expose us to the risk of increasing interest rates.

The table below provides information about our interest rate-sensitive instruments as of December 31, 2009 and 2008 prior to the impact of the Dropdown and related debt issuance. Long-term debt in the table represents principal cash flows by expected maturity date. The fair value of our private debt is valued based on the prices of similar securities with similar terms and credit ratings.

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	2011	2012	2017	Total	Fair Value December 31, 2009	Fair Value December 31, 2008
				(In millions)		
Long-term debt (1):						
Fixed rate	$ 150	$	$ 600	$ 750	$ 763	$ 592
Interest rate	7.50%		7.25%			
Variable rate	$	$ 250	$	$ 250	$ 237	$ 233
Interest rate(2)						

(1) Excludes unamortized discount and premium.

(2) The variable interest rate at December 31, 2009 was 1.23%. The weighted-average interest rate for 2009 is applicable base rate plus 0.89%.

Interest Rate Risk after Completion of the Dropdown

The Dropdown and related debt issuance had a significant impact on our debt portfolio. The table below provides information about our interest rate-sensitive instruments following the Dropdown and related debt issuance. Long-term debt in the table represents principal cash flows by expected maturity date.

	2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Long-term debt, including current portion (1):							
Fixed rate	$ 15	$ 459	$ 325	$	$	$ 5,452	$ 6,251
Interest rate	6.0%	6.0%	5.9%	5.8%	5.8%	6.2%	
Variable rate	$	$	$	$ 250	$	$	$ 250
Interest rate (2)							

(1) Excludes unamortized discount and premium.

(2) The interest rate for the $250

million variable rate debt under the New Credit Facility is LIBOR plus 2.75%.

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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 general partner s Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2009, 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, 2009, 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.

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

The Board of Directors of Williams Partners GP LLC
General Partner of Williams Partners L.P.
and the Limited Partners of Williams Partners L.P.

We have audited Williams Partners L.P. s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Williams Partners L.P. s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Williams Partners L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009 based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the accompanying consolidated balance sheets of Williams Partners L.P. as of December 31, 2009 and 2008, and the related consolidated statements of income, partners capital, and cash flows for each of the three years in the period ended December 31, 2009, and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 25, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Williams Partners GP LLC
General Partner of Williams Partners L.P.
and the Limited Partners of Williams Partners L.P.

We have audited the accompanying consolidated balance sheets of Williams Partners L.P. as of December 31, 2009 and 2008, and the related consolidated statements of income, partners capital, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Williams Partners L.P. at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Williams Partners L.P. s internal control over financial reporting as of December 31, 2009, 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 25, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 25, 2010

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WILLIAMS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 144,067	$ 116,165
Accounts receivable:		
Trade	17,210	16,279
Affiliate	22,635	11,652
Other	1,581	2,919
Product imbalance	10,583	6,344
Prepaid expenses and other current assets	7,392	7,744
Total current assets	203,468	161,103
Investment in Wamsutter	272,549	277,707
Investment in Discovery Producer Services	188,511	184,466
Property, plant and equipment, net	634,233	640,520
Other noncurrent assets	24,909	28,023
Total assets	$ 1,323,670	$ 1,291,819
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable:		
Trade	$ 18,777	$ 22,348
Affiliate	20,231	11,122
Product imbalance	12,437	8,926
Deferred revenue	4,983	4,916
Accrued interest	18,722	18,705
Other accrued liabilities	13,626	6,172
Total current liabilities	88,776	72,189
Long-term debt	1,000,000	1,000,000
Other noncurrent liabilities	19,499	16,020
Commitments and contingent liabilities (Note 16)		
Partners capital:		
Common unitholders (52,777,452 units outstanding at December 31, 2009 and 2008)	1,630,604	1,619,954
Accumulated other comprehensive loss	(561)	
General partner	(1,414,648)	(1,416,344)
Total partners capital	215,395	203,610
Total liabilities and partners capital	$ 1,323,670	$ 1,291,819

See accompanying notes to consolidated financial statements.

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WILLIAMS PARTNERS L.P.
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2009	2008	2007
	(Dollars in thousands, except per-unit amounts)		
Revenues:			
Product sales:			
Affiliate	$ 167,487	$ 314,299	$ 267,970
Third-party	14,981	24,981	22,962
Gathering and processing:			
Affiliate	43,978	37,893	35,819
Third-party	187,825	195,056	202,775
Storage	33,209	31,429	28,016
Fractionation	10,584	17,441	9,622
Other	12,125	15,961	5,653
Total revenues	470,189	637,060	572,817
Costs and expenses:			
Product cost and shrink replacement:			
Affiliate	37,167	85,372	73,475
Third-party	66,058	120,706	108,223
Operating and maintenance expense:			
Affiliate	48,199	76,735	61,633
Third-party	114,865	109,166	100,710
Depreciation, amortization and accretion	44,887	45,029	46,492
General and administrative expense:			
Affiliate	47,253	44,065	42,038
Third-party	3,992	2,994	3,590
Taxes other than income	10,149	9,508	9,624
Other (income) expense net	(4,133)	(3,523)	12,095
Total costs and expenses	368,437	490,052	457,880
Operating income	101,752	147,008	114,937
Equity earnings Wamsutter	84,052	88,538	76,212
Discovery investment income	27,243	22,357	28,842
Interest expense	(60,679)	(67,220)	(58,348)
Interest income	99	706	2,988
Net income	$ 152,467	$ 191,389	$ 164,631
Allocation of net income for calculation of earnings per unit:			
Net income	$ 152,467	$ 191,389	$ 164,631
Allocation of net income to general partner	511	28,957	79,507
Allocation of net income to limited partners	$ 151,956	$ 162,432	$ 85,124

Basic and diluted net income per limited partner unit	$ 2.88	$ 3.08	$ 1.99
Weighted average number of common units outstanding	52,777,452	52,775,710(a)	40,131,195(a)(b)

(a) Includes subordinated units converted to common on February 19, 2008.

(b) Includes Class B units converted to common on May 21, 2007.

See accompanying notes to consolidated financial statements.

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WILLIAMS PARTNERS L.P.
CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

	Limited Partners					
	Common	Class B	Subordinated	General Partner	Accumulated Other Comprehensive Loss	Total Partners Capital
				(In thousands)		
Balance December 31, 2006	$ 733,878	$ 241,923	$ 108,862	$ (613,322)	$	$ 471,341
Comprehensive income:						
Net income 2007	64,546	9,212	14,995	75,878		164,631
Other comprehensive loss:						
Net unrealized losses on cash flow hedges					(3,763)	(3,763)
Reclassification into earnings of derivative instrument losses					1,276	1,276
Total other comprehensive loss						(2,487)
Total comprehensive income						162,144
Cash distributions	(59,573)	(6,601)	(14,315)	(6,792)		(87,281)
Conversion of Class B units into common (6,805,492 units)	244,534	(244,534)				
Distributions to general partner in exchange for additional investment in Discovery Producer Services				(78,000)		(78,000)
Adjustment in basis of investment in Discovery Producer Services				(9,035)		(9,035)
Issuance of units to public (9,250,000 common units)	335,220					335,220
Issuance of units to general partner (4,163,257 common units)	157,173					157,173
				(750,000)		(750,000)

Distributions to general partner in exchange for investment in Wamsutter					
Offering costs	(1,927)				(1,927)
Adjustment in basis of investment in Wamsutter			(53,807)		(53,807)
Contributions from general partner			10,334		10,334
Contributions pursuant to the omnibus agreement			5,362		5,362
Other	(37)				(37)
Balance December 31, 2007	1,473,814	109,542	(1,419,382)	(2,487)	161,487
Net income 2008	163,917	1,556	25,916		191,389
Other comprehensive income:					
Net unrealized gains on cash flow hedges				2,903	2,903
Reclassification into earnings of derivative instrument gains				(416)	(416)
Total other comprehensive income					2,487
Total comprehensive income					193,876
Cash distributions	(124,483)	(4,025)	(26,874)		(155,382)
Conversion of subordinated units into common (7,000,000 units)	107,073	(107,073)			
Contributions pursuant to the omnibus agreement			2,981		2,981
Issuance of units to public (800,000 common units)	28,992				28,992
Repurchase of units from Williams (800,000 common units)	(28,992)				(28,992)
Other	(367)		1,015		648
Balance December 31, 2008	1,619,954		(1,416,344)		203,610

Net income	2009	144,684	7,783	152,467

	Limited Partners					
	Common	Class B	Subordinated	General Partner	Accumulated Other Comprehensive Loss	Total Partners Capital
			(In thousands)			
Other comprehensive income:						
Net unrealized losses on cash flow hedges					(2,411)	(2,411)
Net unrealized losses on cash flow hedges Wamsutter					(685)	(685)
Reclassification of losses into earnings					1,850	1,850
Reclassification of losses into earnings Wamsutter					685	685
Total other comprehensive loss						(561)
Total comprehensive income						151,906
Cash distributions	(134,052)			(10,156)		(144,208)
Contributions pursuant to the omnibus agreement				4,069		4,069
Other	18					18
Balance December 31, 2009	$ 1,630,604	$	$	$ (1,414,648)	$ (561)	$ 215,395

See accompanying notes to consolidated financial statements.

WILLIAMS PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
OPERATING ACTIVITIES:			
Net income	$ 152,467	$ 191,389	$ 164,631
Adjustments to reconcile to cash provided by operations:			
Depreciation, amortization and accretion	44,887	45,029	46,492
Provision for loss on property, plant and equipment		6,827	11,306
Amortization of gas purchase contract affiliate			4,754
Gain on involuntary conversion	(4,034)	(11,604)	
Equity earnings of Wamsutter	(84,052)	(88,538)	(76,212)
Equity earnings of Discovery Producer Services	(23,023)	(20,641)	(28,842)
Distributions related to equity earnings of Wamsutter	84,052	95,926	
Distributions related to equity earnings of Discovery Producer Services	23,023	20,641	26,240
Cash provided (used) by changes in assets and liabilities:			
Accounts receivable	(10,576)	4,955	11,830
Prepaid expenses	(955)	(46)	(369)
Reimbursable projects		8,989	(8,989)
Other current assets	1,307	(1,373)	(1,041)
Accounts payable	5,118	(16,827)	13,959
Product imbalance	(728)	1,769	162
Accrued liabilities	9,290	(2,344)	15,914
Deferred revenue	(167)	59	1,709
Other, including changes in noncurrent assets and liabilities	2,001	4,632	4,313
Net cash provided by operating activities	198,610	238,843	185,857
INVESTING ACTIVITIES:			
Purchase of additional investment in Discovery Producer Services			(69,061)
Purchase of investment in Wamsutter			(277,262)
Cumulative distributions in excess of equity earnings of Wamsutter	6,169	3,213	
Cumulative distributions in excess of equity earnings of Discovery Producer Services	9,121	35,759	229
Capital expenditures	(36,841)	(49,304)	(46,530)
Receipt of insurance proceeds	5,000	13,140	
Contribution to Wamsutter	(1,012)	(3,658)	
Contribution to Discovery Producer Services	(13,166)	(5,700)	
Proceeds from sales of property, plant and equipment	162		
Net cash used by investing activities	(30,567)	(6,550)	(392,624)
FINANCING ACTIVITIES:			
Proceeds from sales of common units		28,992	492,393
Proceeds from debt issuances			250,000
Redemption of common units from general partner		(28,992)	

Excess purchase price over the contributed basis of the investment in Discovery Producer Services			(8,939)
Excess purchase price over the contributed basis of the investment in Wamsutter			(472,738)
Payment of debt issuance costs			(1,781)
Payment of offering costs			(1,927)
Distributions to unitholders and general partner	(144,208)	(155,382)	(87,281)
General partner contributions	4,069	2,981	15,696
Other	(2)	76	
Net cash provided (used) by financing activities	(140,141)	(152,325)	185,423
Increase (decrease) in cash and cash equivalents	27,902	79,968	(21,344)
Cash and cash equivalents at beginning of year	116,165	36,197	57,541
Cash and cash equivalents at end of year	$ 144,067	$ 116,165	$ 36,197

See accompanying notes to consolidated financial statements.

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WILLIAMS PARTNERS L. P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization

Unless the context clearly indicates otherwise, references in this report to we, our, us or similar language refer to Williams Partners L.P. and its subsidiaries. Unless the context clearly indicates otherwise, references to we, our, and us include the operations of Wamsutter LLC (Wamsutter) and Discovery Producer Services LLC (Discovery) in which we own interests accounted for as equity investments that are not consolidated in our financial statements. When we refer to Wamsutter or Discovery by name, we are referring exclusively to their businesses and operations.

We are a publicly-traded Delaware limited partnership. Williams Partners GP LLC, a Delaware limited liability company and wholly owned by The Williams Companies, Inc. (Williams), serves as our general partner and owns a 2% general partner interest, a 6% limited partner interest (as of December 31, 2009) and incentive distribution rights in us. All of our activities are conducted through Williams Partners Operating LLC (OLLC), an operating limited liability company (wholly owned by us).

We have evaluated our disclosure of subsequent events through February 25, 2010, the date that the financial statements were filed.

Note 2. Dropdown

On February 17, 2010, we closed a transaction with our general partner, our operating company and certain subsidiaries of and including Williams, pursuant to which Williams contributed to us the ownership interests in the entities that make up Williams Gas Pipeline and Midstream Gas & Liquids business segments to the extent not already owned by us, including Williams limited and general partner interests in Williams Pipeline Partners L.P. (WMZ), but excluding Williams Canadian, Venezuelan and olefins operations and 25.5% of Gulfstream Natural Gas System, L.L.C. (Gulfstream), collectively referred to as the Contributed Entities. This contribution was made in exchange for aggregate consideration of:

- $3.5 billion in cash, less certain expenses incurred by us,
- 203 million of our Class C limited partnership units, and
- an increase in the capital account of our general partner to allow it to maintain its 2% general partner interest.

The transactions described in the preceding paragraph are referred to as the Dropdown. We financed the cash portion of the consideration by issuing $3.5 billion of senior unsecured notes (see Note 11, Long-Term Debt, Credit Facilities and Leasing Activities). Because the acquired entities were affiliates of Williams at the time of the acquisition, this transaction will be accounted for as a combination of entities under common control, similar to a pooling of interests, whereby the assets and liabilities of the acquired entities will be combined with ours at their historical amounts. During 2010, we will retrospectively adjust our financial statements to reflect this accounting.

The following tables summarize the impact of the acquisition on our financial position and results of operations as of and for the year ended December 31, 2009 on a retrospectively adjusted basis and does not reflect the issuance of debt to finance that acquisition.

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Supplemental Retrospectively Adjusted Balance Sheet Data (at December 31, 2009) (unaudited)

	Williams Partners L.P. Historical	Contributed Entities	Eliminations	Retrospectively Adjusted
	(In millions)			
Total assets	$1,324	$10,968	$ (286)(a)	$ 12,006
Property, plant and equipment, net	634	9,591		10,225
Long-term debt, including current portion	1,000	1,996		2,996
Total partners capital/equity	215	7,681	(273)	7,623

(a) Includes the elimination of our equity investment in Wamsutter since Wamsutter is consolidated by the Contributed Entities. Also includes the elimination of $13 million in accounts receivable from the Contributed Entities.

Supplemental, Retrospectively Adjusted Statement of Income Data: (unaudited)

	Years Ended December 31, 2009	2008	2007
	(In millions)		
Revenues:			
Williams Partners historical revenues	$ 470	$ 637	$ 573
Contributed Entities historical revenues	4,226	5,455	5,326
Less: eliminations (a)	(167)	(314)	(268)
Revenues	$ 4,529	$ 5,778	$ 5,631
Net Income:			
Williams Partners historical net income	$ 152	$ 191	$ 165
Contributed Entities historical net income	962	1,997	1,360
Less: equity earnings Wamsutter (b)	(84)	(89)	(76)
Net income (c) (d)	$ 1,030	$ 2,099	$ 1,449

(a) Includes elimination of product sales revenues derived from sales between us and the Contributed Entities.

(b) Includes the elimination of equity earnings from Wamsutter since Wamsutter is consolidated by the Contributed Entities.

(c) Does not reflect interest associated with the $3.5 billion senior unsecured notes. Future operating results will include additional interest expense associated with this new long-term debt.

(d) The Contributed Entities historical net income includes income taxes related to Transco and Northwest Pipeline (as defined in Note 3). Transco and Northwest Pipeline converted from corporations to limited liability companies on December 31, 2008 and October 1, 2007, respectively, and are not subject to income taxes after those respective dates. The effect of Transco and Northwest Pipeline s change in tax status resulted in a significant benefit for income taxes during 2008 and 2007 for the Contributed Entities.

Note 3. Description of Business

We are principally engaged in the business of gathering, transporting, processing and treating natural gas and fractionating and storing natural gas liquids (NGL). Operations of our businesses are located in the United States and are organized into three reporting segments: (1) Gathering and Processing-West, (2) Gathering and Processing-Gulf and (3) NGL Services. Our Gathering and

Processing-West segment includes the Four Corners gathering and processing operations and our equity investment in Wamsutter. Our Gathering and Processing-Gulf segment includes the Carbonate Trend gathering pipeline and our equity investment in Discovery. Our NGL Services segment includes the Conway fractionation and storage operations.

Gathering and Processing-West. Our Four Corners natural gas gathering, processing and treating assets consist of, among other things, (1) an approximately 3,800-mile natural gas gathering system in the San Juan Basin in New Mexico and Colorado with a capacity of two billion cubic feet per day, (2) the Ignacio natural gas processing plant in Colorado and the Kutz and Lybrook natural gas processing plants in New Mexico, which have a combined processing capacity of 765 million cubic feet per day (MMcf/d) and (3) the Milagro and Esperanza natural gas treating plants in New Mexico, which have a combined carbon dioxide removal capacity of 70 MMcf/d.

Wamsutter owns (1) an approximate 1,880-mile natural gas gathering system in the Washakie Basin in south-central Wyoming that currently connects approximately 2,100 wells, with a typical operating capacity of approximately 500 MMcf/d at current operating pressures, and (2) the Echo Springs cryogenic processing plant near Wamsutter, Wyoming which has 390 MMcf/d of inlet cryogenic processing capacity and NGL production capacity of 30,000 barrels per day (bpd).

Gathering and Processing-Gulf. We own a 60% interest in Discovery, which includes a wholly owned subsidiary, Discovery Gas Transmission LLC. Discovery owns (1) an approximate 350-mile natural gas gathering and transportation pipeline system, located primarily off the coast of Louisiana in the Gulf of Mexico, (2) a 600 MMcf/d cryogenic natural gas processing plant in Larose, Louisiana, (3) a 32,000 bpd natural gas liquids fractionator in Paradis, Louisiana and (4) a 22-mile mixed NGL pipeline connecting the gas processing plant to the fractionator. Although Discovery includes fractionation operations, which would normally fall within the NGL Services segment, it is primarily engaged in gathering and processing and is managed as such. Hence, this equity investment is considered part of the Gathering and Processing-Gulf segment.

Our Carbonate Trend gathering pipeline is an unregulated sour gas gathering pipeline consisting of approximately 34 miles of pipeline off the coast of Alabama.

NGL Services. Our Conway storage facilities include three underground NGL storage facilities in the Conway, Kansas area with a storage capacity of approximately 21 million barrels. The facilities are connected via a series of pipelines. The storage facilities receive daily shipments of a variety of products, including mixed NGLs and fractionated products. In addition to pipeline connections, one facility offers truck and rail service.

Our Conway fractionation facility is located near Conway, Kansas and has a capacity of approximately 107,000 bpd. We own a 50% undivided interest in these facilities representing capacity of approximately 53,500 bpd. ConocoPhillips and ONEOK Partners, L.P. are the other owners. We operate the facility pursuant to an operating agreement that extends until May 2011. The fractionator separates mixed NGLs into five products: ethane, propane, normal butane, isobutane and natural gasoline. Portions of these products are then transported and stored at our Conway storage facilities.

Dropdown. Following the Dropdown, our business activities will be organized into two reporting segments: Gas Pipeline and Midstream Gas & Liquids. Our current operations will be part of the Midstream Gas & Liquids segment, and the newly acquired businesses will be reflected in Gas Pipeline and Midstream Gas & Liquids as follows:

Gas Pipeline will include Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline GP (Northwest Pipeline), which own and operate a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,700 trillion British thermal units of natural gas and peak-day delivery capacity of approximately 12 million dekatherms of gas. Gas Pipeline will also hold interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5% interest in Gulfstream, which owns an approximately 745-mile pipeline with the capacity to transport approximately 1.26 million dekatherms per day of natural gas.

Midstream Gas & Liquids will include the contributed midstream entities with large natural gas gathering, treating, and processing operations and oil transportation pipelines. These facilities serve major producing basins in Colorado, Wyoming, Pennsylvania, the Gulf Coast and the Gulf of Mexico.

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Note 4. Summary of Significant Accounting Policies

Principles of Consolidation. The consolidated financial statements include the accounts of our parent company, Williams Partners L.P., the OLLC and our wholly owned subsidiaries and our investments. We apply the equity method of accounting for our investments (see Note 7, Equity Investments). We eliminated all intercompany accounts and transactions and reclassified certain amounts to conform to the current classifications.

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.

Estimates and assumptions which, in the opinion of management, are significant to the underlying amounts included in the financial statements and for which it would be reasonably possible that future events or information could change those estimates include:

- loss contingencies;
- valuations of derivatives;
- impairment assessments of long-lived assets;
- environmental remediation obligations; and
- asset retirement obligations.

These estimates are discussed further throughout the accompanying notes.

Proportional Accounting for the Conway Fractionator. No separate legal entity exists for the fractionator. We hold a 50% undivided interest in the fractionator property, plant and equipment, and we are responsible for our proportional share of the costs and expenses of the fractionator. As operator of the facility, we incur the liabilities of the fractionator (except for certain fuel costs purchased directly by one of the co-owners) and are reimbursed by the co-owners for their proportional share of the total costs and expenses. Each co-owner is responsible for the marketing of their proportional share of the fractionator s capacity. Accordingly, we reflect our proportionate share of the revenues and costs and expenses of the fractionator in the Consolidated Statements of Income, and we reflect our proportionate share of the fractionator property, plant and equipment in the Consolidated Balance Sheets. Liabilities in the Consolidated Balance Sheets include those incurred on behalf of the co-owners with corresponding receivables from the co-owners. Accounts receivable also includes receivables from our customers for fractionation services.

Cash and Cash Equivalents. Cash and cash equivalents include 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 maturities of three months or less when acquired.

Accounts Receivable. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. We do not recognize an allowance for doubtful accounts at the time the revenue which generates the accounts receivable is recognized. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of our customers, and the amount and age of past due accounts. We consider receivables past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been unsuccessful. The allowance for doubtful accounts at December 31, 2009 and 2008 was immaterial.

Product Imbalances. In the course of providing gathering, processing and treating services to our customers, we realize over and under deliveries of our customers products and over and under purchases of shrink replacement gas when our purchases vary from operational requirements. In addition, in the course of providing gathering, processing, treating, fractionation and storage services to our customers, we realize gains and losses due to (1) the product blending process at the Conway fractionator, (2) the periodic emptying of storage caverns at Conway and (3) inaccuracies inherent in the gas measurement process. These gains and losses impact our results of operations and are included in operating and maintenance expense in the Consolidated Statements of Income. These imbalance positions are reflected as product imbalance receivables and payables on the Consolidated Balance Sheets. We value product imbalance receivables based on the lower of current market prices or current cost of natural gas in the system or, in the case of our Conway facilities, lower of the current market prices or weighted average value of NGLs. We value product imbalance payables at current market prices. The majority of Four Corners product imbalance settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several periods. In some cases, settlements of imbalances build up over a period of time and are ultimately settled in cash and are generally negotiated at values which approximate average market prices over a period of time. These gains and losses impact our results of operations and are included in operating and maintenance expense in the Consolidated Statements of Income.

Prepaid Expenses and Leasing Activities. Prepaid expenses include the unamortized balance of minimum lease payments made to date under a right-of-way renewal agreement. We capitalize land and right-of-way lease payments made at the time of initial construction or placement of plant and equipment on leased land as part of the cost of the assets. Lease payments made in connection with subsequent renewals or amendments of these leases are classified as prepaid expenses. The minimum lease payments for the lease term, including any renewal, are expensed on a straight-line basis over the lease term.

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 a physical energy commodity. The counterparty to these instruments is a Williams affiliate. We execute these transactions in over-the-counter markets in which quoted prices exist for active periods. We report the fair value of derivatives, except those for which the normal purchases and normal sales exception has been elected, on the Consolidated Balance Sheets in other current assets, other accrued liabilities, other assets or other noncurrent liabilities. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual contracts. We report these amounts on a gross basis.

The accounting for changes in the fair value of derivatives depends on whether the derivative has been designated in a hedging relationship and what type of hedging relationship it is. The accounting for the change in fair value can be summarized as follows:

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

We have elected 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 since we made the election of this exception at the inception of these contracts.

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 other revenues.

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

Investments. At December 31, 2009, our ownership interests in Wamsutter consist of 100% of the Class A limited liability company interests and 108 Class C units representing 69% of the Class C ownership interests (collectively the Wamsutter Ownership Interests). At December 31, 2008, our ownership interests consisted of 100% of the Class A interests and 20 Class C units representing 50% of the Class C interests. We account for our Wamsutter Ownership Interests and our 60% investment in Discovery under the equity method due to the voting provisions of their limited liability company agreements which provide the other members of these entities significant participatory rights such that we do not control these investments. Discovery s underlying equity exceeds the carrying value of our investment at December 31, 2009 and 2008 due to an other-than-temporary impairment of that investment that we recognized in 2004 and the acquisition of an additional interest in Discovery at a cost that was less than the corresponding share of the underlying net assets of Discovery. These differences are being amortized over the expected remaining life of the Discovery assets.

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. Depreciation of property, plant and equipment is provided on the straight-line basis over estimated useful lives. Expenditures for maintenance and repairs are expensed as incurred. Expenditures that enhance the functionality or extend the useful lives of the assets are capitalized. We remove the cost of property, plant and equipment sold or retired and the related accumulated depreciation from the accounts in the period of sale or disposition. Gains and losses on the disposal of property, plant and equipment are recorded in other (income) expense net in the Consolidated Statements of Income.

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. 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 corresponding accretion expense.

Revenue Recognition. The nature of our businesses results in various forms of revenue recognition. Our Gathering and Processing segments recognize (1) revenue from fee-based gathering and processing of gas in the period the service is provided based on contractual terms and the related natural gas and liquid volumes and (2) product sales revenue when the product has been delivered. Our NGL Services segment recognizes (1) fractionation revenues when services have been performed and product has been delivered, (2) storage revenues under prepaid contracted storage capacity evenly over the life of the contract as services are provided and (3) product sales revenue when the product has been 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 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 the carrying value of the assets is recoverable. We apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes. If the carrying value is not recoverable, 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.

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 estimated fair value is recognized in the financial statements as an impairment.

Judgments and assumptions are inherent in our management s estimate of undiscounted future cash flows used to determine recoverability of an asset and the estimate of an asset s or investment s fair value used to calculate the amount of impairment to recognize. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

Environmental. Environmental expenditures that relate to current or future revenues are expensed or capitalized based upon the nature of the expenditures. Expenditures that relate to an existing contamination caused by past operations that do not contribute to current or future revenue generation are expensed. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account our prior remediation experience, and are not discounted. Environmental contingencies are recorded independently of any potential claim for recovery.

Capitalized Interest. We capitalize interest during construction on major projects with construction periods of at least three months and a total project cost in excess of $1.0 million. Interest is capitalized based on our average interest rate on debt to the extent we incur interest expense. Capitalized interest for the periods presented is immaterial.

Income Taxes. We are not a taxable entity for federal and state income tax purposes. The tax on our net income is borne by the individual partners through the allocation of taxable income. Net income for financial statement purposes may differ significantly from taxable income of unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregated difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner s tax attributes in us is not available to us.

Earnings Per Unit. We use the two-class method to calculate basic and diluted earnings per unit whereby net income, adjusted for items specifically allocated to our general partner, is allocated on a pro-rata basis between unitholders and our general partner. Basic and diluted earnings per unit are based on the average number of common, Class B and subordinated units outstanding. Basic and diluted earnings per unit are equivalent as there are no dilutive securities outstanding.

Recent Accounting Standards. In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements . This Update requires new disclosures regarding the amount of transfers in or out of Level 1 and Level 2 fair value measurements along with the reason for such transfers and also requires a greater level of disaggregation when disclosing valuation techniques and inputs used in estimating Level 2 and Level 3 fair value measurements. The disclosures will be required for reporting beginning in the first quarter 2010. Also, beginning with the first quarter of 2011, the Update requires additional categorization of items included in the rollforward of activity for Level 3 fair value measurements on a gross basis. We are assessing the application of this Update to disclosures in our Consolidated Financial Statements.

Note 5. Allocation of Net Income and Distributions

The allocation of net income between our general partner and limited partners, as reflected in the Consolidated Statement of Partners Capital, for the years ended December 31, 2009, 2008 and 2007 is as follows (in thousands):

	Year Ended December 31,		
	2009	**2008**	**2007**
Allocation of net income to general partner:			
Net income	$ 152,467	$ 191,389	$ 164,631
Net income applicable to pre-partnership operations allocated to general partner			(71,426)
Beneficial conversion of Class B units*			(5,308)
Reimbursable general and administrative and other costs charged directly to general partner	2,590	1,712	2,400
Income subject to 2% allocation of general partner interest	155,057	193,101	90,297
General partner s share of net income	2.0%	2.0%	2.0%
General partner s allocated share of net income before items directly allocable to general partner interest	3,101	3,861	1,806
Incentive distributions paid to general partner**	7,272	23,767	5,046
Charges allocated directly to general partner	(2,590)	(1,712)	(2,400)
Pre-partnership net income allocated to general partner interest			71,426
Net income allocated to general partner	$ 7,783	$ 25,916	$ 75,878

Net income	$ 152,467	$ 191,389	$ 164,631
Net income allocated to general partner	7,783	25,916	75,878
Net income allocated to limited partners	$ 144,684	$ 165,473	$ 88,753

* The $5.3 million allocation of income to the Class B units reflects the Class B unit beneficial conversion feature resulting from the May 2007 conversion of these units into common units on a one-for-one basis. We computed the $5.3 million beneficial conversion feature as the product of the 6,805,492 Class B units and the difference between the fair value of a privately placed common unit on the date of issuance ($36.59) and the issue price of a privately placed Class B unit ($35.81).

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** In the calculation of basic and diluted net income per limited partner unit, the net income allocated to the general partner includes IDRs pertaining to the current reporting period, but paid in the subsequent period. The net income allocated to the general partner s capital account reflects IDRs paid during the current reporting period. In April 2009, Williams waived the IDRs related to 2009 distribution periods. The IDRs paid in 2009 relate to the fourth-quarter 2008 distribution.

Pursuant to the partnership agreement, we allocate income on a quarterly basis. Common and subordinated unitholders shared equally, on a per-unit basis, in the net income allocated to limited partners before the conversion of the subordinated units into common units in 2008.

The reimbursable general and administrative and other costs represent the costs charged against our income that our general partner is required to reimburse us under the terms of the omnibus agreement.

We paid or have authorized payment of the following cash distributions during 2007, 2008 and 2009 (in thousands, except for per unit amounts):

General Partner

Payment Date	Per Unit Distribution	Common Units	Subordinated Units	Class B Units	2%	Incentive Distribution Rights	Total Cash Distribution
2/14/2007	$0.4700	$12,010	$ 3,290	$3,198	$390	$ 603	$19,491
5/15/2007	$0.5000	$12,777	$ 3,500	$3,403	$421	$ 965	$21,066
8/14/2007	$0.5250	$16,989	$ 3,675	$	$447	$1,267	$22,378
11/14/2007	$0.5500	$17,799	$ 3,850	$	$487	$2,211	$24,347
2/14/2008	$0.5750	$26,321	$ 4,025	$	$706	$4,231	$35,283
5/15/2008	$0.6000	$31,665	$	$	$758	$5,499	$37,922
8/14/2008	$0.6250	$32,984	$	$	$811	$6,765	$40,560
11/14/2008	$0.6350	$33,513	$	$	$832	$7,272	$41,617
2/13/2009	$0.6350	$33,513	$	$	$832	$7,272	$41,617
5/15/2009	$0.6350	$33,513	$	$	$684	$	$34,197
8/14/2009	$0.6350	$33,513	$	$	$684	$	$34,197
11/13/2009	$0.6350	$33,513	$	$	$684	$	$34,197
2/12/2010(a)	$0.6350	$33,513	$	$	$684	$	$34,197

(a) On February 12, 2010, we paid a cash distribution of $0.635 per unit on our outstanding common units to unitholders of record on February 5, 2010.

Note 6. Related Party Transactions

The employees of our operated assets and all of our general and administrative employees are employees of Williams. Williams directly charges us for the payroll costs associated with the operations employees. Williams carries the obligations for most employee-related benefits in its financial statements, including the liabilities related to the employee retirement and medical plans and paid time off. We charge back certain of the payroll costs associated with the operations employees to the other Conway fractionator co-owners. Our share of those costs is charged to us through affiliate billings and reflected in Operating and maintenance expense Affiliate in the accompanying Consolidated Statements of Income.

We are charged for certain administrative expenses by Williams and its Midstream segment of which we are a part. These charges are either directly identifiable or allocated to our assets. Direct charges are for goods and services provided by Williams and Midstream at our request. Allocated charges are either (1) charges allocated to the Midstream segment by Williams and then reallocated from the Midstream segment to us or (2) Midstream-level administrative costs that are allocated to us. These allocated corporate administrative expenses are based on a three-factor formula, which considers revenues; property, plant and equipment; and payroll. We charge certain of these costs back to the other Conway fractionator co-owners. Our share of direct and allocated administrative expenses is reflected in General and administrative expense Affiliate in the accompanying Consolidated Statements of Income. In management s estimation, the allocation methodologies used are reasonable and result in a reasonable allocation to us of our costs of doing business incurred by Williams. Under the omnibus agreement, Williams gives us a quarterly credit for general and administrative expenses. These amounts are reflected as capital contributions from our general partner. The annual amounts of the credits are as follows: $2.4 million in 2007, $1.6 million in 2008 and $0.8 million in 2009. In 2009 we amended our omnibus agreement to increase the aggregate amount of the credit we could receive related to certain general and administrative expenses for

2009. Williams agreed to provide up to an additional $10.0 million credit, in addition to the $0.8 million annual credit previously provided under the original omnibus agreement, to the extent that 2009 non-segment profit general and administrative expenses exceeded $36.0 million (exclusive of certain expenses related to the Dropdown). We recorded total general and administrative expenses (including those expenses subject to the credit by Williams) as an expense, and we recorded any credits as capital contributions from Williams. Accordingly, our net income does not reflect the benefit of the credit received from Williams. However, the cost subject to this credit is allocated entirely to our general partner. As a result, the net income allocated to limited partners on a per-unit basis reflects the benefit of this credit. The total general and administrative credit received from Williams in 2009 was $2.6 million.

At December 31, 2009 and 2008 we have a contribution receivable from our general partner of $0.8 million and $0.2 million, respectively, for amounts reimbursable to us under the omnibus agreement. We net this receivable against Partners capital on the Consolidated Balance Sheets.

During 2009 and 2008, Williams reimbursed us $1.8 million and $1.6 million, respectively, for capital expenditures in connection with Discovery s Tahiti pipeline lateral expansion project.

We purchase natural gas for shrink replacement and fuel for Four Corners and the Conway fractionator, including fuel on behalf of the Conway co-owners, from Williams Gas Marketing, Inc. (WGM), a wholly owned subsidiary of Williams. Natural gas purchased for fuel is reflected in Operating and maintenance expense Affiliate, and natural gas purchased for shrink replacement is reflected in Product cost and shrink replacement Affiliate in the accompanying Consolidated Statements of Income. These purchases are generally made at market rates at the time of purchase or contract execution. In connection with our 2005 initial public offering, Williams transferred to us a gas purchase contract for the purchase of a portion of our fuel requirements at the Conway fractionator at a market price not to exceed a specified level. We reflect the amortization of this contract in Operating and maintenance expense Affiliate in the accompanying Consolidated Statements of Income. This contract terminated on December 31, 2007.

Four Corners uses waste heat from a co-generation plant located adjacent to the Milagro treating plant. Williams Flexible Generation, LLC, an affiliate of Williams, owns the co-generation plant. Waste heat is required for the natural gas treating process, which occurs at Milagro. The charge to us for the waste heat is based on the natural gas needed to generate the waste heat. We purchase this natural gas from WGM. We reflect this cost in Operations and maintenance expense Affiliate.

The operation of the Four Corners gathering system includes the routine movement of gas across gathering systems. We refer to this activity as crosshauling. Crosshauling typically involves the movement of some natural gas between gathering systems at established interconnect points to optimize flow, reduce expenses or increase profitability. As a result, we must purchase gas for delivery to customers at certain plant outlets and we have excess volumes to sell at other plant outlets. WGM conducts these purchase and sales transactions at current market prices at each location. These transactions are included in Product sales Affiliate and Product cost and shrink replacement Affiliate on the Consolidated Statements of Income. Historically, WGM has not charged us a fee for providing this service, but has occasionally benefited from price differentials that historically existed from time to time between the plant outlets.

We sell the NGLs to which we take title on the Four Corners system to Williams NGL Marketing LLC (WNGLM), a wholly owned subsidiary of Williams. We reflect revenues associated with these activities as Product sales Affiliate on the Consolidated Statements of Income. We conduct these transactions at current market prices for the products.

We periodically enter into financial swap contracts with WGM and WNGLM to hedge forecasted NGL sales. These contracts are priced based on market rates at the time of execution and are reflected in Other accrued liabilities on the Consolidated Balance Sheets.

One of our major customers is Williams Production Company (WPC), a wholly owned subsidiary of Williams. WPC is one of the largest natural gas producers in the San Juan Basin and we provide natural gas gathering, treating and processing services to WPC under several contracts. One of the contracts with WPC is adjusted annually based on changes in the average price of natural gas. We reflect revenues associated with these activities in the Gathering and processing Affiliate on the Consolidated Statements of Income.

We sell Conway s surplus propane and other NGLs to WNGLM, which takes title to the product and resells it, for its own account, to end users. Revenues associated with these activities are reflected as Product sales Affiliate on the

Consolidated Statements of Income. Correspondingly, we purchase ethane and other NGLs for Conway from WNGLM to replenish deficit product imbalance positions. We conduct transactions between us and WNGLM at current market prices for the products.

Under our stand-alone cash management program, we reflect amounts owed by us or to us by Williams or its subsidiaries as Accounts receivable Affiliate or Accounts payable Affiliate in the accompanying Consolidated Balance Sheets.

Note 7. Equity Investments

Wamsutter

The interests in Wamsutter not held by us are held by a Williams affiliate, and Williams is the operator of Wamsutter. As such, Williams is reimbursed on a monthly basis for all direct and indirect expenses it incurs on behalf of Wamsutter including Wamsutter s allocable share of general and administrative costs.

Wamsutter purchases natural gas for fuel and shrink replacement from WGM and sells NGLs to WNGLM. Wamsutter conducts these transactions at current market prices for the products.

Wamsutter participates in Williams cash management program and, therefore, carries no cash balances.

Our consolidated financial statements and notes reflect our Wamsutter Ownership Interests, which we acquired in December 2007. However, certain cash transactions resulting from Wamsutter s participation in Williams cash management program, which occurred between Wamsutter and Williams prior to this acquisition, are not reflected in our Consolidated Statements of Cash Flows even though these transactions affect the carrying value of our Wamsutter Ownership Interests. These transactions were omitted from our Consolidated Statements of Cash Flows because they did not affect our cash. Our Consolidated Statement of Partners Capital reflects the total of these transactions as an adjustment in the basis of our investment in Wamsutter.

The Wamsutter LLC Agreement provides for quarterly distributions of available cash beginning in March 2008. Available cash is defined as cash generated from Wamsutter s business less reserves that are necessary or appropriate to provide for the conduct of its business and to comply with applicable law and or debt instrument or other agreement to which it is a party.

Wamsutter distributes its available cash as follows:

First, an amount equal to $17.5 million per quarter to the holder of the Class A membership interests. We currently own 100% of the Class A interests;

Second, an amount equal to the amount the distribution on the Class A membership interests in prior quarters of the current distribution year was less than $17.5 million per quarter to the holder of the Class A membership interests; and

Third, 5% of remaining available cash shall be distributed to the holder of the Class A membership interests and 95% shall be distributed to the holders of the Class C units, on a *pro rata* basis. At December 31, 2009 and 2008, we owned 69% and 50% of the Class C units, respectively.

In addition, to the extent that at the end of the fourth quarter of a distribution year, the Class A member has received less than $70.0 million under the first and second bullets above, the Class C members will be required to repay any distributions they received in that distribution year such that the Class A member receives $70.0 million for that distribution year. If this repayment is insufficient to result in the Class A member receiving $70.0 million, the shortfall will not carry forward to the next distribution year. The distribution year for Wamsutter commences each year on December 1 and ends on November 30.

Wamsutter allocates net income (equity earnings) to us based upon the allocation, distribution, and liquidation provisions of its limited liability company agreement applied as though liquidation occurs at book value. In general, the agreement allocates income in a manner that will maintain capital account balances reflective of the amounts each membership interest would receive if Wamsutter were dissolved and liquidated at carrying value. The income allocation for the quarterly periods during a year reflects the preferential rights of the Class A member to any distributions made to the Class C member until the Class A member has received $70.0 million in distributions for the year. The Class B member receives no income or loss allocation. As the owner of 100% of the Class A membership interest, we will receive 100% of Wamsutter s annual net income up to $70.0 million. Income in excess of $70.0 million will be shared between the Class A member and Class C member. For annual periods in which Wamsutter s net income exceeds $70.0 million, this will result in a higher allocation of equity earnings to us early in the year and a lower allocation of equity earnings to us later in the year. Wamsutter s net income allocation does not affect the amount of available cash it distributes for any quarter. All

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of the 2009 net income was allocated to the Class A member. The following table presents the allocation of Wamsutter s 2008 and 2009 net income to its unitholders:

Wamsutter Net Income Allocation 2008		Wamsutter Net Income
Net income for December 1, 2007 November 30, 2008	$	110.1
Less net income allocated for transition support contribution		(7.6)
Less net income for December 2007		(7.4)
Net income for 2008 allocation	$	95.1

	Class A	Our Share Class C	WPZ Total (Millions)	Other Class C	Wamsutter Net Income
Allocation up to $70 million (excluding December 2007 allocation)	$ 62.6	$	$ 62.6	$	$ 62.6
Allocation of net income over $70 million	2.1	15.2	17.3	15.2	32.5
Income allocation for transition support contribution	7.6		7.6		7.6
December 2008 income allocation	1.0		1.0		1.0
Totals	$ 73.3	$ 15.2	$ 88.5	$ 15.2	$ 103.7

Wamsutter Net Income Allocation 2009		Wamsutter Net Income
Net income for December 1, 2008 November 30, 2009	$	77.3
Less net income allocated for transition support contribution		(9.7)
Less net income for December 2008		(1.0)
Net income for 2009 allocation	$	66.6

	Class A	Our Share Class C	WPZ Total (Millions)	Other Class C	Wamsutter Net Income
Allocation up to $70 million (excluding December 2008 allocation)	$ 66.6	$	$ 66.6	$	$ 66.6
	9.7		9.7		9.7

Income allocation for transition support contribution					
December 2009 income allocation	7.8		7.8		7.8
Totals	$ 84.1	$	$ 84.1	$	$ 84.1

Wamsutter s LLC agreement provides that it receive a transition support payment related to a cap on general and administrative expenses from its Class B membership interest each quarter through 2012. Although the full amount of expenses is recorded by Wamsutter, this support increases the cash distributable and income allocable to the Class A membership interest.

During 2009 and 2008, we made capital contributions of $1.0 million and $3.7 million, respectively, to Wamsutter for capital projects and received total cash distributions of $80.5 million and $91.5 million, respectively, from Wamsutter, as well as transition support payments of $9.7 million and $7.6 million, respectively.

During 2009, Wamsutter issued an additional 88.5 and 28.8 Class C units to us and Williams, respectively, related to the funding of expansion capital expenditures placed in service during 2009 and 2008. As of December 31, 2009, Williams contributed an additional $82.9 million for an expansion capital project that is expected to be placed in service during 2010. Williams contributed $28.8 million for that project in 2008. Williams will receive Class C units related to these expenditures after the assets are placed in service.

Following the February 2010 Dropdown, we own 100% of Wamsutter and consolidate them.

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The summarized financial position and results of operations for 100% of Wamsutter are presented below (in thousands).

	December 31,	
	2009	2008
Current assets	$ 21,691	$ 17,147
Property, plant and equipment	408,429	318,072
Non-current assets	3,071	468
Current liabilities	(29,220)	(16,960)
Non-current liabilities	(4,846)	(4,353)
Members capital	$ 399,125	$ 314,374

	Years Ended December 31,		
	2009	2008	2007
Revenues:			
Product sales:			
Affiliate	$ 95,734	$ 134,776	$ 93,744
Third-party	$ 15,348	27,384	7,447
Gathering and processing services	79,523	68,670	67,904
Other revenues	5,282	8,704	6,214
Costs and expenses excluding depreciation and accretion:			
Affiliate	51,478	74,388	46,834
Third-party	38,122	40,200	32,666
Depreciation and accretion	22,235	21,182	18,424
Net income	$ 84,052	$ 103,764	$ 77,385
Williams Partners interest equity earnings	$ 84,052	$ 88,538	$ 76,212

Discovery Producer Services

Williams is the operator of Discovery. Discovery reimburses Williams for actual operations related payroll and employee benefit costs incurred on its behalf. In addition, Discovery pays Williams a monthly operations and management fee to cover the cost of accounting services, computer systems and management services provided to it. Discovery also has an agreement with Williams pursuant to which (1) Discovery purchases a portion of the natural gas from WGM to meet its fuel and shrink replacement needs at its processing plant and (2) WNGLM purchases the NGLs and excess natural gas to which Discovery takes title.

Our consolidated financial statements and notes reflect the additional 20% interest in Discovery which we acquired in mid-2007. Prior to this acquisition, Discovery distributed $9 million of cash to Williams that related to the additional 20% interest. This distribution is not reflected in our Consolidated Statements of Cash Flows even though these distributions affect the carrying value of our investment in Discovery because they did not affect our cash. Our Consolidated Statement of Partners Capital reflects the total of these distributions as an adjustment in the basis of our investment in Discovery.

During 2009 and 2008, we contributed $13.2 million and $5.7 million, respectively to Discovery for capital projects.

During 2009, 2008 and 2007 we received total cash distributions of $32.1 million, $56.4 million and $35.5 million, respectively, from Discovery for the 60% interest we currently own or the 40% interest we owned at the time of distribution.

The summarized financial position and results of operations for 100% of Discovery are presented below (in thousands).

	December 31, 2009	December 31, 2008
Current assets	$ 39,454	$ 50,978
Non-current restricted cash		3,470
Property, plant and equipment	364,932	370,482
Current liabilities	(16,708)	(45,234)
Non-current liabilities	(23,355)	(19,771)
Members capital	$ 364,323	$ 359,925

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	Years Ended December 31,		
	2009	2008	2007
Revenues:			
Affiliate	$ 115,354	$ 209,994	$ 220,960
Third-party	45,665	31,254	39,712
Costs and expenses:			
Affiliate	35,815	96,912	101,581
Third-party	88,160	110,508	113,207
Interest income	(31)	(650)	(1,799)
Foreign exchange (gain) loss	168	78	(388)
Net income	$ 36,907	$ 34,400	$ 48,071
Discovery investment income:			
Williams Partners interest equity earnings	$ 23,023	$ 20,641	$ 28,842
Business interruption insurance proceeds (a)	4,220	1,716	
Discovery investment income	$ 27,243	$ 22,357	$ 28,842

(a) Proceeds received due to hurricane damage sustained in 2008.

Note 8. Other (Income) Expense

Other (income) expense net reflected on the Consolidated Statements of Income consists of the following items (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Involuntary conversion gains	$ (4,034)	$ (11,604)	$
Impairment of Carbonate Trend pipeline		6,187	10,406
Other	(99)	1,894	1,689
Total	$ (4,133)	$ (3,523)	$ 12,095

Involuntary conversion gains. On November 28, 2007, the Ignacio gas processing plant sustained significant damage from a fire. The involuntary conversion gains result from insurance proceeds received to replace the capital assets destroyed by the fire in excess of the net book value of those assets being replaced.

Impairment of Carbonate Trend Pipeline. During 2007 and again in 2008, we determined that the carrying value of this pipeline, included in our Gathering and Processing Gulf segment, may not be recoverable because of forecasted declining cash flows. As a result, we recognized impairment charges of $6.2 million and $10.4 million in 2008 and 2007, respectively, to reduce the carrying value to management s estimate of fair value. As of December 31, 2008, the carrying value of this asset was written down to zero. We estimated fair value using discounted cash flow projections.

Note 9. Property, Plant and Equipment

Property, plant and equipment, at cost, is as follows:

	December 31, 2009	December 31, 2008	Estimated Depreciable Lives
	(In thousands)		
Land and right of way	$ 43,650	$ 43,246	0-30 years
Gathering pipelines and related equipment	850,067	838,214	20-30 years
Processing plants and related equipment	195,474	183,222	30 years
Fractionation plant and related equipment	16,681	16,540	30 years
Storage plant and related equipment	96,347	87,803	30 years
Buildings and other equipment	77,228	77,287	3-45 years
Construction work in progress	17,351	18,841	
Total property, plant and equipment	1,296,798	1,265,153	
Accumulated depreciation	662,565	624,633	
Net property, plant and equipment	$ 634,233	$ 640,520	

Depreciation expense for 2009, 2008 and 2007 was $42.4 million, $42.7 million and $42.2 million, respectively.

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Our asset retirement obligations relate to gas processing and compression facilities located on leased land, wellhead connections on federal land, underground storage caverns and the associated brine ponds and offshore pipelines. At the end of the useful life of each respective asset, we are legally or contractually obligated to remove certain surface equipment and cap certain gathering pipelines at the wellhead connections, properly abandon the storage caverns and offshore pipelines, empty the brine ponds and restore the surface, and remove any related surface equipment.

A rollforward of our asset retirement obligation for 2009 and 2008 is presented below.

	2009	2008
	(In thousands)	
Balance, January 1	$ 13,465	$ 8,743
Liabilities incurred during the period		355
Liabilities settled during the period.		
Accretion expense	972	752
Estimate revisions	361	3,615
Balance, December 31	$ 14,798	$ 13,465

Note 10. Major Customers and Concentrations of Credit Risk

Major customers

Our largest customer, on a percentage of revenues basis, is WNGLM, which purchases and resells substantially all of the NGLs to which we take title. WNGLM accounted for 37%, 49% and 49% of revenues in 2009, 2008 and 2007, respectively. The remaining largest customer, ConocoPhillips, from our Gathering and Processing West segment, accounted for 23%, 17% and 22% of revenues in 2009, 2008 and 2007, respectively.

Concentrations of Credit Risk

Our cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government. The counterparties to our derivative contracts are affiliates of Williams, which minimized our credit risk exposure.

The following table summarizes the concentration of accounts receivable by service and segment.

	December 31,	
	2009	2008
	(In thousands)	
Gathering and Processing West:		
Natural gas gathering and processing	$ 15,063	$ 14,516
Other	897	801
Gathering and Processing Gulf:		
Natural gas gathering	205	203
NGL Services:		
Fractionation services	839	1,025
Amounts due from fractionator partners	650	1,439
Storage	1,102	681
Other	35	34
Accrued interest and other		499
Affiliate	22,635	11,652
	$ 41,426	$ 30,850

At December 31, 2009 and 2008, a substantial portion of our accounts receivable results from product sales and gathering and processing services provided to two of our customers. One customer is an affiliate of Williams which minimizes our credit risk exposure. The remaining customer may impact our overall credit risk either positively or negatively, in that this entity may be affected by industry-wide changes in economic or other conditions. As a general policy, collateral is not required for receivables, but customers financial conditions and credit worthiness are evaluated regularly. Our credit policy and the relatively short duration of receivables mitigate the risk of uncollectible receivables.

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Note 11. Long-Term Debt, Credit Facilities and Leasing Activities

Long-Term Debt

Long-term debt at December 31, 2009 and 2008 includes the following:

	Interest Rate	December 31, 2009	2008
		(Millions)	
Credit agreement term loan, adjustable rate, due 2012	(a)	$ 250.0	$ 250.0
Senior unsecured notes, fixed rate, due 2017	7.25%	600.0	600.0
Senior unsecured notes, fixed rate, due 2011	7.50%	150.0	150.0
Total Long-term debt		$ 1,000.0	$ 1,000.0

(a) 1.23% at December 31, 2009

The terms of the senior unsecured notes are governed by indentures that contain covenants that, among other things, limit (1) our ability and the ability of our subsidiaries to incur indebtedness or liens securing indebtedness and (2) mergers, consolidations and transfers of all or substantially all of our properties or assets. The indentures also contain customary events of default, upon which the trustee or the holders of the senior unsecured notes may declare all outstanding senior unsecured notes to be due and payable immediately.

We may redeem the senior unsecured notes at our option in whole or in part at any time or from time to time prior to the respective maturity dates, at a redemption price per note equal to the sum of (1) the then outstanding principal amount thereof, plus (2) accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date), plus (3) a specified make-whole premium (as defined in the indenture). Additionally, upon a change of control (as defined in the indenture), each holder of the senior unsecured notes will have the right to require us to repurchase all or any part of such holder s senior unsecured notes at a price equal to 101% of the principal amount of the senior unsecured notes plus accrued and unpaid interest, if any, to the date of settlement. Except upon a change of control as described in the prior sentence, we are not required to make mandatory redemption or sinking fund payments with respect to the senior unsecured notes or to repurchase the senior unsecured notes at the option of the holders.

Cash payments for interest during 2009, 2008 and 2007 were $57.9 million, $65.5 million and $38.8 million, respectively.

In connection with the February 2010 Dropdown, we issued $3.5 billion face value of senior unsecured notes and assumed $2.0 billion face value of outstanding debt of Transco, Northwest Pipeline and Williams Laurel Mountain, LLC as follows:

	Interest Rate	Millions
Senior unsecured notes, fixed rate, due 2015	3.80%	$ 750.0
Senior unsecured notes, fixed rate, due 2020	5.25%	1,500.0
Senior unsecured notes, fixed rate, due 2040	6.30%	1,250.0
Total debt issuance at face value		3,500.00
Transco, 6.05% to 8.875%, payable through 2026	7.24%	1,282.5

Northwest, 5.95% to 7.125%, payable through 2025	6.39%	695.0
Williams Laurel Mountain, LLC, 8.00% to 10.00%, payable through 2012	8.00%	23.8
Total debt assumed at face value, including current portion		2,001.3
Total additional long-term debt at face value, including current portion		$ 5,501.3

In connection with the issuance of the $3.5 billion notes discussed above, we entered into registration rights agreements with the initial purchasers of the notes. We are obligated to file a registration statement for an offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 180 days from closing and use its commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing and to consummate the exchange offers within 30 business days after such effective date. We may also be required to provide a shelf registration statement to cover resales of the notes under certain circumstances. If we fail to fulfill these obligations, additional interest will accrue on the affected securities. The rate of additional interest will be 0.25% per annum on the principal amount of the affected securities for the first 90-day period immediately following the occurrence of default, increasing by an additional 0.25% per annum with respect to each subsequent 90-day period thereafter, up to a maximum amount for all such defaults of 0.5% annually. Following the cure of any registration defaults, the accrual of additional interest will cease.

Credit Facilities

At December 31, 2009, we had a $450.0 million senior unsecured credit agreement (Credit Agreement) with Citibank, N.A. as administrative agent, comprised initially of a $200.0 million revolving credit facility available for borrowings and letters of credit and a $250.0 million term loan. We expect that our ability to borrow under this facility is reduced by $12.0 million due to the bankruptcy of a participating bank. However, debt covenants may restrict the full use of the credit facility. We must repay borrowings under the Credit Agreement by December 11, 2012. At December 31, 2009 and 2008, we had a $250.0 million term loan outstanding under the term loan provisions and no other amounts outstanding under the Credit Agreement. As a result of the second-quarter 2009 Fitch Ratings downgrade of our senior unsecured debt rating from BB+ to BB, our applicable margin on the $250.0 million term loan increased 0.25% to 1.0% and the commitment fee on the unused capacity of our revolver increased 0.05% to 0.175%.

In connection with the Dropdown, we terminated the Credit Agreement and entered into a new $1.75 billion three-year senior unsecured revolving credit facility (New Credit Facility) with Transco and Northwest Pipeline, as co-borrowers, and Citibank, N.A. as the administrative agent, and certain other lenders named therein. The full amount of the New Credit Facility is available to us, to the extent not otherwise utilized by Transco and Northwest Pipeline, and may be increased by up to an additional $250 million. Transco and Northwest Pipeline are each able to borrow up to $400 million under the New Credit Facility to the extent not otherwise utilized by us. At closing, we borrowed $250 million under the New Credit Facility to repay the $250 million term loan outstanding under the Credit Agreement.

Interest on borrowings under the New Credit Facility is payable at rates per annum equal to, at the option of the borrower: (1) a fluctuating base rate equal to Citibank, N.A. s adjusted base rate plus the applicable margin or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. The adjusted base rate will be the highest of (i) the federal funds rate plus 0.5%, (ii) Citibank N.A. s publicly announced base rate and (iii) one-month LIBOR plus 1.0%. We pay a commitment fee (currently 0.5%) based on the unused portion of the New Credit Facility. The applicable margin and the commitment fee are determined by reference to a pricing schedule based on a borrower s senior unsecured debt ratings.

The New Credit Facility contains various covenants that limit, among other things, a borrower s and its respective subsidiaries ability to incur indebtedness, grant certain liens supporting indebtedness, merge, or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default and allow any material change in the nature of its business.

In addition, we are required to maintain a ratio of debt to EBITDA (each as defined in the New Credit Facility) of no greater than 5.00 to 1.00 for us and our consolidated subsidiaries. For each of Transco and Northwest Pipeline and their respective consolidated subsidiaries, the ratio of debt to capitalization (defined as net worth plus debt) is not permitted to be greater than 55%. Each of the above ratios will be tested, beginning June 30, 2010, at the end of each fiscal quarter, and the debt to EBITDA ratio will be measured on a rolling four-quarter basis.

The New Credit Facility includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-payment defaults, cross acceleration, bankruptcy and insolvency events, certain unsatisfied judgments and a change of control. If an event of default with respect to a borrower occurs under the New Credit Facility, the lenders will be able to terminate the commitments for all borrowers and accelerate the maturity of the loans of the defaulting borrower under the New Credit Facility and exercise other rights and remedies.

We also had a $20.0 million revolving credit facility with Williams as the lender. The facility was available exclusively to fund working capital requirements. We paid a commitment fee to Williams on the unused portion of the credit facility of 0.125% annually. As of December 31, 2009, we had no outstanding borrowings under the working capital credit facility. This facility was terminated in connection with the Dropdown.

Leasing Activities

We lease the land on which a significant portion of Four Corners pipeline assets are located. The primary landowners are the Bureau of Land Management (BLM) and several Indian tribes. The BLM leases are for thirty years with renewal options. A significant Indian tribal lease in Colorado will expire at the end of 2022.

Under our right-of-way agreement with the Jicarilla Apache Nation (JAN), beginning in 2010, we will make annual payments of approximately $7.5 million and an additional annual payment which varies depending on the prior year s per-unit NGL margins and the volume of gas gathered by our gathering facilities subject to the agreement. Depending primarily on the per-unit NGL margins for any given year, the additional annual payments could approximate the fixed amount. Additionally, on April 1, 2014, the JAN will have the option to acquire up to a 50% joint venture interest for 20 years in certain of Four Corners assets existing at the time the option is exercised. The joint venture option includes Four Corners gathering assets subject to the agreement and portions of Four Corners gathering and processing assets located in an area adjacent to the JAN lands. If the JAN selects the joint venture option, the value of the assets contributed by each party to the joint venture will be based upon a market value determined by a neutral third party at the time the joint venture is formed.

We also lease other minor office, warehouse equipment and automobiles under non-cancelable leases. The future minimum annual rentals under these non-cancelable leases as of December 31, 2009 are payable as follows:

	(In thousands)
2010	$ 13,849
2011	8,149
2012	7,823
2013	7,571
2014 and thereafter	112,920
	$ 150,312

Total rent expense was $13.2 million, $24.4 million and $21.2 million for 2009, 2008 and 2007, respectively.

Note 12. Partners Capital

At December 31, 2009, the public held 76% of our total units outstanding, and affiliates of Williams held the remaining units.

In connection with the Dropdown, we issued 203 million Class C limited partnership units to Williams. The Class C units are identical to our common limited partnership units except that for the first quarter of 2010 they will receive a prorated quarterly distribution since they were not outstanding during the full quarterly period. The Class C units will automatically convert into our common limited partnership units following the record date for the first-quarter 2010 distribution.

Limited Partners Rights

Significant rights of the limited partners include the following:

- Right to receive distributions of available cash within 45 days after the end of each quarter.

- No limited partner shall have any management control over our business and affairs; the general partner shall conduct, direct and manage our activities.

- The general partner may be removed if such removal is approved by the unitholders holding at least 66 2/3% of the outstanding units voting as a single class, including units held by our general partner and its affiliates.

Subordinated Units

Our subordination period ended on February 19, 2008 when we met the requirements for early termination pursuant to our partnership agreement. As a result of the termination, the 7,000,000 outstanding subordinated units owned by four subsidiaries of Williams converted one-for-one to common units and now participate pro rata with the other common units in distributions of available cash.

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Class B Units

On May 21, 2007, the Class B units were converted into common units on a one-for-one basis and now participate pro rata with the other common units in distributions of available cash.

Incentive Distribution Rights

Our general partner is entitled to incentive distributions if the amount we distribute to unitholders with respect to any quarter exceeds specified target levels shown below:

Quarterly Distribution Target Amount (per unit)	Unitholders	General Partner
Minimum quarterly distribution of $0.35	98%	2%
Up to $0.4025	98	2
Above $0.4025 up to $0.4375	85	15
Above $0.4375 up to $0.5250	75	25
Above $0.5250	50	50

In April 2009, Williams waived the incentive distribution rights related to 2009 distribution periods.

In the event of liquidation, all property and cash in excess of that required to discharge all liabilities will be distributed to the unitholders and our general partner in proportion to their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Issuances of Additional Partnership Securities

Our partnership agreement allows us to issue additional partnership securities for any partnership purpose at any time and from time to time for consideration and on terms and conditions as our general partner determines, all without the approval of any limited partners.

Note 13. Fair Value Measurements

Fair value is the amount received to sell an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement from the perspective of a market participant. We use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We apply both market and income approaches for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

Effective January 1, 2009, we applied new fair value accounting requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed at fair value on a recurring basis. We applied a prospective transition as we did not have any financial instrument transactions that required a cumulative-effect adjustment to beginning equity. This adoption did not materially impact our Consolidated Financial Statements.

The fair-value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair-value balances based on the observability of those inputs. The three levels of the fair-value hierarchy are as follows:

Level 1 Quoted prices in active markets for identical assets or liabilities that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

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Level 2 Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured.

Level 3 Includes inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management s best estimate of the assumptions market participants would use in determining fair value. Our Level 3 consists of instruments valued with valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair-value measurement requires judgment and may affect the placement within the fair-value hierarchy levels.

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis. At December 31, 2008 we had no assets or liabilities measured at fair value on a recurring basis.

Fair Value Measurements Using:

	December 31, 2009			
	Level 1	**Level 2**	**Level 3**	**Total**
	(In thousands)			
Assets:				
Energy derivatives	$	$	$	$
Liabilities:				
Energy derivatives	$	$	$561	$561

Energy derivatives include commodity-based contracts with WGM that are similar to exchange-traded contracts and over-the-counter (OTC) contracts. Exchange-traded contracts could include futures, swaps and options. OTC contracts could include forwards, swaps and options.

Certain instruments trade in less active markets with lower availability of pricing information requiring valuation models using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. Our commodity-based NGL financial swap contracts are included in Level 3.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as collateral posted and letters of credit), and our nonperformance risk on our liabilities.

The following table sets forth a reconciliation of changes in the fair value of net derivatives classified as Level 3 in the fair-value hierarchy.

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Level 3 Fair-Value Measurements Using Significant Unobservable Inputs
Years Ended December 31, 2009 and 2008
(In thousands)

	Net Derivative Asset (Liability) December 31, 2009	2008
Beginning balance	$	$ (2,487)
Realized and unrealized gains (losses):		
Included in net income	(1,892)	(200)
Included in other comprehensive income (loss)	(561)	416
Purchases, issuances and settlements	1,892	2,487
(Gains) losses realized in settlements		(216)
Transfers in/(out) of Level 3		
Ending balance	$ (561)	$
Unrealized gains included in net income relating to instruments still held at December 31	$	$

Realized and unrealized gains (losses) included in net income are reported in revenues in our Consolidated Statements of Income. During the year ended December 31, 2009, there were no assets or liabilities measured at fair value on a nonrecurring basis.

Note 14. Financial Instruments and Energy Commodity Derivatives

Financial Instruments

We used the following methods and assumptions to estimate the fair value of financial instruments.

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

Long-term debt. The fair value of our publicly traded long-term debt is valued using indicative year-end traded bond market prices. We base the fair value of our private long-term debt on market rates and the prices of similar securities with similar terms and credit ratings. We consider our non-performance risk in estimating fair value. At December 31, 2009 and 2008 approximately 75% of our long-term debt was publicly traded.

Energy commodity swap agreements. We base the fair value of our swap agreements on prices of the underlying energy commodities over the contract life and contractual or notional volumes with the resulting expected future cash flows discounted to a present value using a risk-free market interest rate. Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market price (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

Carrying amounts and fair values of our financial instruments

	2009		2008	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
		(In thousands)		
Cash and cash equivalents	$ 144,067	$ 144,067	$ 116,165	$ 116,165
Long-term debt	(1,000,000)	(999,867)	(1,000,000)	(825,289)
Energy derivative liabilities	(561)	(561)		

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Energy Commodity Derivatives

Risk Management Activities

We are exposed to market risk from changes in energy commodity prices within our operations. Our Four Corners operation receives NGL volumes as compensation for certain processing services and purchases natural gas to satisfy the required fuel and shrink replacement needed to extract these NGLs. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices or increases in costs and operating expenses from fluctuations in natural gas market prices, we may enter NGL or natural gas swap agreements, financial or physical forward contracts, and financial option contracts to mitigate these commodity price risks.

All of these derivatives utilized for risk management purposes have been designated as cash flow hedges. Our cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. No net gains or losses from hedge ineffectiveness are included in our Consolidated Statements of Income in either 2009 or 2007. We recognized a $0.2 million net loss from hedge ineffectiveness in our Consolidated Statements of Income in 2008. There were no derivative gains or losses excluded from the assessment of hedge effectiveness for the periods presented. Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in accumulated other comprehensive loss and are reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period.

Volumes

Our energy commodity derivatives are comprised of contracts to sell NGLs at a fixed location price. The following table depicts the notional volumes in our commodity derivatives portfolio as of December 31, 2009.

	Period	**Volumes**
Designated as hedging instruments:		
NGL sales propane (million gallons)	January December 2010	4.3

Financial Statement Presentation

The fair value of our energy commodity derivatives designated as hedging instruments is included in other accrued liabilities in our Consolidated Balance Sheets at December 31, 2009. We had no energy commodity derivatives at December 31, 2008. There are no derivatives recognized on the Consolidated Balance Sheets that have not been designated as hedging instruments. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements.

The following table presents gains and losses for our energy commodity derivatives designated as cash flow hedges and recognized in accumulated other comprehensive income (AOCI) or revenues. There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness for the periods presented.

	2009	**Classification**
	(In thousands)	
Net loss recognized in other comprehensive income (effective portion)	$2,411	AOCI
Net loss reclassified from accumulated other comprehensive loss into income (effective portion)	$1,850	Revenues
Gain recognized in income (ineffective portion)	$	Revenues

Based on recorded values at December 31, 2009, $0.6 million of net losses will be reclassified into earnings within the next twelve months. These recorded values are based on market prices of the commodities as of December 31, 2009. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized in 2010 will likely differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements for the volumes associated with underlying hedged transactions.

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Credit-Risk

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Risk of loss is impacted by several factors, including credit considerations. We attempt to minimize credit-risk exposure to derivative counterparties through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures and collateral support under certain circumstances. Our NGL financial swap contracts are with WGM. These agreements do not contain any provisions that require us to post collateral related to net liability positions. Historically, WGM has not passed any counterparty risk back to us when they enter offsetting NGL financial contracts with third parties.

Note 15. Long-Term Incentive Plan

Our general partner maintains the Williams Partners GP LLC Long-Term Incentive Plan (the Plan) for employees, consultants and directors of our general partner and its affiliates who perform services for us. Initially, the Plan permitted granting of awards covering an aggregate of 700,000 common units, in the form of options, restricted units, phantom units or unit appreciation rights. During 2009 the Director s Compensation Policy under the Plan was amended to a 100% cash compensation program, thereby eliminating the issuance of any partnership units. The revisions to the policy do not affect restricted units previously granted.

During 2008 and 2007 our general partner granted 2,724 and 2,403 restricted units, respectively, pursuant to the Plan to members of our general partner s board of directors who are not officers or employees of our general partner or its affiliates. These restricted units vested 180 days from the grant date. We recognized compensation expense of $20,000, $98,000 and $77,000 associated with the Plan in 2009, 2008 and 2007, respectively, based on the market price of our common units at the date of grant. No awards were granted under the plan in 2009.

Note 16. Commitments and Contingencies

Commitments. A summary of our commitments for goods and services used in our operations and for construction and acquisition of property, plant and equipment at December 31, 2009, is as follows:

	2010	2011	2012	2013	Total
		(In thousands)			
Property, plant and equipment	$ 5,163	$	$	$	$ 5,163
Outstanding purchase orders	4,661				$ 4,661
Purchase obligations (a)	22,563	17,587	17,938	17,938	$76,026

(a) Represents a five-year service agreement for leased compression.

Environmental Matters-Four Corners. Current federal regulations require that certain unlined liquid containment pits located near named rivers and catchment areas be taken out of use, and current state regulations required all unlined, earthen pits to be either permitted or closed by December 31, 2005. Operating under a New Mexico Oil Conservation Division-approved work plan, we have physically closed all of our pits that were slated for closure under those regulations. We are presently awaiting agency approval of the closures for 40 to 50 of those pits. We are also a participant in certain hydrocarbon removal and groundwater monitoring activities associated with certain well sites in New Mexico. Of nine remaining active sites, product removal is ongoing at four and groundwater monitoring is ongoing at each site. As groundwater concentrations reach and sustain closure criteria levels and state regulator approval is received, the sites will be properly abandoned. We expect the remaining sites will be closed within four to seven years.

In April 2007, the New Mexico Environment Department s Air Quality Bureau (NMED) issued a Notice of Violation (NOV) that alleges various emission and reporting violations in connection with our Lybrook gas processing plant s flare and leak detection and repair program. In December 2007, the NMED proposed a penalty of approximately $3 million. In July 2008, the NMED issued an NOV that alleged air emissions permit exceedances for three glycol dehydrators at one of our compressor facilities and proposed a penalty of approximately $103,000. We are discussing the proposed penalties with the NMED.

In March 2008, the Environmental Protection Agency (EPA) proposed a penalty of $370,000 for alleged violations relating to leak detection and repair program delays at our Ignacio gas plant in Colorado and for alleged permit violations at a compressor station. We met with the EPA and are exchanging information in order to resolve the issues.

We have accrued liabilities totaling $1.4 million at December 31, 2009 for these environmental activities. It is reasonably possible that we will incur losses in excess of our accrual for these matters. However, a reasonable estimate of such amounts cannot be determined at this time because actual costs incurred will depend on the actual number of contaminated sites identified, the amount and extent of contamination discovered, the final cleanup standards mandated by governmental authorities, negotiations with the applicable agencies, and other factors.

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Environmental Matters-Conway. We are a participant in certain environmental remediation activities associated with soil and groundwater contamination at our Conway storage facilities. These activities relate to four projects that are in various remediation stages including assessment studies, cleanups and/or remedial operations and monitoring. We continue to coordinate with the Kansas Department of Health and Environment (KDHE) to develop screening, sampling, cleanup and monitoring programs. The costs of such activities will depend upon the program scope ultimately agreed to by the KDHE and are expected to be paid over the life of the assets. At December 31, 2009, we had accrued liabilities totaling $5.2 million for these costs. It is reasonably possible that we will incur losses in excess of our accrual for these matters. However, a reasonable estimate of such amounts cannot be determined at this time because actual costs incurred will depend on the actual number of contaminated sites identified, the amount and extent of contamination discovered, the final cleanup standards mandated by KDHE and other governmental authorities and other factors.

Under an omnibus agreement with Williams entered into at the closing of our initial public offering, Williams agreed to indemnify us for certain Conway environmental remediation costs. At December 31, 2009, approximately $6.9 million remains available for future indemnification. Payments received under this indemnification are accounted for as a capital contribution to us by Williams as the costs are reimbursed.

Will Price. In 2001, we were named, along with other subsidiaries of Williams, as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs and sought an unspecified amount of damages. The defendants have opposed class certification, and on September 18, 2009, the court denied plaintiffs   most recent motion to certify the class. On October 2, 2009, the plaintiffs filed a motion for reconsideration of the denial. We are awaiting a decision from the court. The amount of any possible liability cannot be reasonably estimated at this time.

GEII Litigation. General Electric International, Inc. (GEII) worked on turbines at our Ignacio, New Mexico plant. We disagree with GEII on the quality of GEII   s work and the appropriate compensation. GEII asserts that it is entitled to additional extra work charges under the agreement, which we deny are due. In 2006, we filed suit in federal court in Tulsa, Oklahoma against GEII, GE Energy Services, Inc., and Qualified Contractors, Inc. We alleged, among other claims, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation and sought unspecified damages. In 2007, the defendants and GEII filed counterclaims in the amount of $1.9 million against us that alleged breach of contract and breach of the duty of good faith and fair dealing. This matter was settled in 2009.

Other. In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

Summary. Litigation, arbitration, regulatory matters and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a material adverse effect upon our future liquidity or financial position.

Note 17. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. We manage the segments separately because each segment requires different industry knowledge, technology and marketing strategies. The accounting policies of the segments are the same as those described in Note 4, Summary of Significant Accounting Policies. Long-lived assets are comprised of property, plant and equipment.

	Gathering & Processing - West	Gathering & Processing - Gulf	NGL Services	Total
	(In thousands)			
2009				
Segment revenues:				
Product sales	$ 172,038	$	$ 10,430	$ 182,468
Gathering and processing	230,095	1,708		231,803
Storage			33,209	33,209
Fractionation			10,584	10,584
Other	4,465		7,660	12,125
Total revenues	406,598	1,708	61,883	470,189
Product cost and shrink replacement	93,387		9,838	103,225
Operating and maintenance expense	136,509	1,459	25,096	163,064
Depreciation, amortization and accretion	41,326	170	3,391	44,887
Direct general and administrative expenses	9,008		3,245	12,253
Other, net	4,815	325	876	6,016
Segment operating income (loss)	121,553	(246)	19,437	140,744
Investment income	84,052	27,243		111,295
Segment profit	$ 205,605	$ 26,997	$ 19,437	$ 252,039
Reconciliation to the Consolidated Statement of Income:				
Segment operating income				$ 140,744
General and administrative expenses:				
Allocated affiliate				(35,536)
Third-party direct				(3,456)
Operating income				$ 101,752
Other financial information:				
Segment assets	$ 1,377,437	$ 491,867	$ 159,882	$ 2,029,186
Other assets and eliminations (a)				(705,516)
Total assets				$ 1,323,670
Equity method investments	$ 272,549	$ 188,511	$	$ 461,060
Additions to long-lived assets	$ 27,032	$ 33	$ 10,196	$ 37,261

(a) Relates primarily to the elimination of intercompany accounts receivable generated by our centralized cash management program. Also includes the assets of the OLLC.

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	Gathering & Processing - West	Gathering & Processing - Gulf	NGL Services	Total
	(In thousands)			
2008				
Segment revenues:				
Product sales	$ 322,583	$	$ 16,697	$ 339,280
Gathering and processing	230,853	2,096		232,949
Storage			31,429	31,429
Fractionation			17,441	17,441
Other	6,702		9,259	15,961
Total revenues	560,138	2,096	74,826	637,060
Product cost and shrink replacement	189,192		16,886	206,078
Operating and maintenance expense	156,713	1,668	27,520	185,901
Depreciation, amortization and accretion	41,215	751	3,063	45,029
Direct general and administrative expenses	8,333		2,582	10,915
Other, net	(939)	6,187	737	5,985
Segment operating income (loss)	165,624	(6,510)	24,038	183,152
Investment income	88,538	22,357		110,895
Segment profit	$ 254,162	$ 15,847	$ 24,038	$ 294,047
Reconciliation to the Consolidated Statement of Income:				
Segment operating income				$ 183,152
General and administrative expenses:				
Allocated affiliate				(33,707)
Third-party direct				(2,437)
Operating income				$ 147,008
Other financial information:				
Segment assets	$ 1,248,110	$ 379,060	$ 127,315	$ 1,754,485
Other assets and eliminations (a)				(462,666)
Total assets				$ 1,291,819
Equity method investments	$ 277,707	$ 184,466	$	$ 462,173
Additions to long-lived assets	$ 36,833	$	$ 9,020	$ 45,853

(a) Relates primarily to the elimination of intercompany accounts receivable generated by our centralized cash management program. Also includes the assets of the OLLC.

	Gathering & Processing - West	Gathering & Processing - Gulf	NGL Services	Total
		(In thousands)		
2007				
Segment revenues:				
Product sales	$ 279,600	$	$ 11,332	$ 290,932
Gathering and processing	236,475	2,119		238,594
Storage			28,016	28,016
Fractionation			9,622	9,622
Other	(2,288)		7,941	5,653
Total revenues	513,787	2,119	56,911	572,817
Product cost and shrink replacement	170,434		11,264	181,698
Operating and maintenance expense	135,782	1,875	24,686	162,343
Depreciation, amortization and accretion	41,523	1,249	3,720	46,492
Direct general and administrative expenses	7,790		2,190	9,980
Other, net	10,567	10,406	746	21,719
Segment operating income (loss)	147,691	(11,411)	14,305	150,585
Investment income	76,212	28,842		105,054
Segment profit	$ 223,903	$ 17,431	$ 14,305	$ 255,639
Reconciliation to the Consolidated Statement of Income:				
Segment operating income				$ 150,585
General and administrative expenses:				
Allocated affiliate				(32,546)
Third-party direct				(3,102)
Operating income				$ 114,937
Other financial information:				
Segment assets	$ 1,112,652	$ 268,471	$ 98,730	$ 1,479,853
Other assets and eliminations (a)				(196,376)
Total assets				$ 1,283,477
Equity method investments	$ 284,650	$ 214,526	$	$ 499,176
Additions to long-lived assets	$ 39,391	$	$ 9,090	$ 48,481

(a) Relates primarily to the elimination of intercompany accounts receivable generated by our centralized cash management program. Also includes the assets of the OLLC.

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QUARTERLY FINANCIAL DATA
(Unaudited)

Summarized quarterly financial data are as follows (thousands, except per-unit amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2009				
Revenues	$ 105,468	$ 106,327	$ 125,153	$ 133,241
Costs and operating expenses	87,847	88,912	88,639	103,039
Net income	18,672	25,368	55,947	52,480
Basic and diluted net income per limited partner unit	$ 0.36	$ 0.48	$ 1.04	$ 0.99

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2008				
Revenues	$ 150,362	$ 178,245	$ 175,713	$ 132,740
Costs and operating expenses	124,050	136,033	127,737	102,232
Net income	43,629	71,822	60,833	15,105(a)(b)
Basic and diluted net income per limited partner unit:				
Common units	$ 0.71	$ 1.21	$ 1.00	$ 0.15
Subordinated units(c)	$ 0.71	$	$	$

(a) During September 2008, Discovery s offshore gathering system sustained hurricane damage and was unable to accept gas from producers while repairs were being made through the end of 2008. In addition, throughout the fourth quarter of 2008 we experienced significantly lower per-unit margins as NGL prices, especially ethane, declined along with the price of crude oil. These lower NGL margins significantly reduced the profitability of our gathering and processing businesses including Four Corners and our ownership interests in Wamsutter and Discovery.

(b) The fourth quarter of 2008 includes a \$6.2 million impairment of the Carbonate Trend pipeline (see Note 8, Other (Income) Expense).

(c) Subordinated units converted to common on February 19, 2008.

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Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

Our management, including our general partner s Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a 15(e) and 15d 15(e) of the Securities Exchange Act) (Disclosure Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Williams Partners L.P. have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our general partner s Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner s Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Management s Annual Report on Internal Control over Financial Reporting

See report set forth above in Item 8, Financial Statements and Supplementary Data.

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

See report set forth above in Item 8, Financial Statements and Supplementary Data.

Changes in Internal Controls Over Financial Reporting

There have been no changes during the fourth quarter of 2009 that have materially affected, or are reasonably likely to materially affect, our Internal Controls over financial reporting.

Item 9B. ***Other Information***

There have been no events that occurred in the fourth quarter of 2009 that would need to be reported on Form 8-K that have not been previously reported.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

As a limited partnership, we have no directors or officers. Instead, our general partner, Williams Partners GP LLC, manages our operations and activities. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation.

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We are managed and operated by the directors and officers of our general partner. All of our operational personnel are employees of affiliates of our general partner.

All of the senior officers of our general partner are also senior officers of Williams and spend a sufficient amount of time overseeing the management, operations, corporate development and future acquisition initiatives of our business. Our non-executive directors devote as much time as is necessary to prepare for and attend board of directors and committee meetings.

The following table shows information for the directors and executive officers of our general partner as of February 25, 2010.

Name	Age	Position with Williams Partners GP LLC
Steven J. Malcolm	61	Chairman of the Board and Chief Executive Officer
Donald R. Chappel	58	Chief Financial Officer and Director
Alan S. Armstrong	47	Senior Vice President Midstream and Director
Phillip D. Wright	54	Senior Vice President Gas Pipeline and Director
James J. Bender	53	General Counsel
H. Michael Krimbill	56	Director and Member of Audit and Conflicts Committees
Bill Z. Parker	62	Director and Member of Audit and Conflicts Committees
Alice M. Peterson	57	Director and Member of Audit and Conflicts Committees

The directors of our general partner are elected for one-year terms and hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors of our general partner. There are no family relationships among any of the directors or executive officers of our general partner.

Steven J. Malcolm has served as the chairman of the board of directors and chief executive officer of our general partner since February 2005. Mr. Malcolm has served as president of Williams since September 2001, chief executive officer of Williams since January 2002 and chairman of the board of directors of Williams since May 2002. From September 2001 to January 2002, he served as chief operating officer of Williams and from May 2001 to September 2001, he served as an executive vice president of Williams. From 1998 to 2001, he served as president and chief executive officer of Williams Energy Services, LLC, a subsidiary of Williams. From 1994 to 1998, Mr. Malcolm served as the senior vice president and general manager of Williams Field Services Company, a subsidiary of Williams. Mr. Malcolm has served as chairman of the board of directors and chief executive officer of the general partner of Williams Pipeline Partners L.P. since 2007. Mr. Malcolm has served as a member of the board of directors of BOK Financial Corporation and Bank of Oklahoma, N.A. since 2002.

Donald R. Chappel has served as the chief financial officer and a director of our general partner since February 2005. Mr. Chappel has served as senior vice president and chief financial officer of Williams since April 2003. Mr. Chappel has served as chief financial officer and a director of the general partner of Williams Pipeline Partners L.P. since 2007.

Alan S. Armstrong has served as a senior vice president of our general partner and president of our midstream business unit since February 17, 2010 and a director of our general partner since February 2005. Since February 2002, Mr. Armstrong has served as a senior vice president of Williams and president of Williams midstream business unit. From 2005 to February 2010, Mr. Armstrong served as the chief operating officer of our general partner. From 1999 to February 2002, Mr. Armstrong was vice president, gathering and processing in Williams midstream business unit and from 1998 to 1999 was vice president, commercial development, in Williams midstream business unit.

Phillip D. Wright has served as a senior vice president and a director of our general partner and president of our gas pipeline business unit since February 17, 2010. Mr. Wright has served as a senior vice president of Williams and president of Williams gas pipeline unit since January 2005. Mr. Wright previously served as a director of our general partner from April 2005 to October 2007. From October 2002 to January 2005, Mr. Wright served as chief restructuring officer of Williams. From September 2001 to October 2002, Mr. Wright served as president and chief executive officer of Williams Energy Services. From 1996 to September 2001, he was senior vice president, enterprise development and planning for Williams energy services group. From 1989 to 1996, Mr. Wright served in various capacities for Williams. Mr. Wright also serves as a director, senior vice president and chief operating officer of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P.

James J. Bender has served as the general counsel of our general partner since February 2005. Mr. Bender has served as senior vice president and general counsel of Williams since December 2002. Mr. Bender has served as the general counsel of the general partner of Williams Pipeline Partners L.P. since August 2007. From June 2000 to June 2002, Mr. Bender was senior vice president and general counsel with NRG Energy, Inc. Mr. Bender was vice president, general counsel and secretary of NRG Energy from June 1997 to June 2000.

H. Michael Krimbill has served as a director of our general partner since August 2007. Mr. Krimbill has served as a director of Seminole Energy Services, LLC, a privately held natural gas marketing company, from November 2007 to February 5, 2010. Mr. Krimbill was the president and chief financial officer of Energy Transfer Partners, L.P. from 2004 until his resignation in January 2007. Mr. Krimbill joined Heritage Propane Partners, L.P. (the predecessor of Energy Transfer Partners) as vice president and chief financial officer in 1990. Mr. Krimbill served as president of Heritage from 1999 to 2004 and as president and chief executive officer of Heritage from 2000 to 2005. Mr. Krimbill also served as a director of Energy Transfer Equity, the general partner of Energy Transfer Partners from 2000 to January 2007.

Bill Z. Parker has served as a director of our general partner since August 2005. Mr. Parker has served as a director of Laredo Petroleum L.L.C., a privately held independent oil and gas producing company, since 2007. Mr. Parker served as a director for Latigo Petroleum, Inc., a privately held independent oil and gas production company, from 2003 to May 2006, when it was acquired by POGO Producing Company. From April 2000 to November 2002, Mr. Parker served as executive vice president of Phillips Petroleum Company s worldwide upstream operations. Mr. Parker was executive vice president of Phillips Petroleum Company s worldwide downstream operations from September 1999 to April 2000.

Alice M. Peterson has served as a director of our general partner since September 2005. Ms. Peterson has served as the chief ethics officer of SAI Global since April 2009. Since 2000, Ms. Peterson has served as a director of RIM Finance, LLC, a wholly owned subsidiary of Research in Motion, Ltd., the maker of Blackberry[tm] handheld device. Ms. Peterson has served as a director of Navistar Financial Corporation, a wholly owned subsidiary of Navistar International, since 2006. She founded and served as the president of Syrus Global, a provider of ethics, compliance and reputation management solutions from 2002 to April 2009, when it was acquired by SAI Global. Ms. Peterson served as a director of Hanesbrands Inc., an apparel company, from 2006 to 2009. Ms. Peterson served as a director of TBC Corporation, a marketer of private branded replacement tires, from July 2005 to November 2005, when it was acquired by Sumitomo Corporation of America. From 1998 to 2004, she served as a director of Fleming Companies. From 2000 to 2001, Ms. Peterson served as president and general manager of RIM Finance, LLC. From April 2000 to September 2000, Ms. Peterson served as the chief executive officer of Guidance Resources.com, a start-up business focused on providing online behavioral health and concierge services to employer groups and other associations. From 1998 to 2000, Ms. Peterson served as vice president of Sears Online and from 1993 to 1998, as vice president and treasurer of Sears, Roebuck and Co.

Governance

Our general partner adopted governance guidelines that address, among other areas, director independence standards, policies on meeting attendance and preparation, executive sessions of non-management directors and communications with non-management directors.

Director Independence

Because we are a limited partnership, the New York Stock Exchange does not require our general partner s board of directors to be composed of a majority of directors who meet the criteria for independence required by the New York Stock Exchange or to maintain nominating/corporate governance and compensation committees composed entirely of independent directors.

Our general partner s board of directors has adopted director independence standards, which are included in our governance guidelines and set forth below. Our governance guidelines are available on our Internet website at *http://www.williamslp.com* under the Investor Relations caption. Under the director independence standards, a director will not be considered to be independent if:

- the director, or an immediate family member of the director, has received during any twelve-month period within the last three years more than $120,000 per year in direct compensation from our general partner, us and any parent or subsidiary in a consolidated group with such entities (collectively, the Partnership Group), other than board and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service). Neither compensation received by a director for former service as an interim chairman or chief executive officer or other executive officer nor compensation received by an immediate family member for service as an employee (other than an executive officer) of the Partnership Group will be considered in determining independence under this standard.

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the director is a current employee, or has an immediate family member who is a current executive officer, of another company that has made payments to, or received payments from, the Partnership Group for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1.0 million, or 2% of the other company s consolidated gross annual revenues. Contributions to tax exempt organizations are not considered payments for purposes of this standard.

the director is, or has been within the last three years, an employee of the Partnership Group, or an immediate family member is, or has been within the last three years, an executive officer, of the Partnership Group. Employment as an interim chairman or chief executive officer or other executive officer will not disqualify a director from being considered independent following that employment.

(i) the director is a current partner or employee of a firm that is the present or former internal or external auditor for the Partnership Group, (ii) the director has an immediate family member who is a current partner of such a firm, (iii) the director has an immediate family member who is a current employee of such a firm and personally works on the Partnership Group s audit (iv) the director or an immediately family member was within the last three years a partner or employee of such a firm and personally worked on an audit for the Partnership Group within that time.

if the director or an immediate family member is, or has been within the last three years, employed as an executive officer of another company where any of the Partnership Group s present executive officers at the same time serves or served on that company s compensation committee.

if the board of directors determines that a discretionary contribution made by any member of the Partnership Group to a non-profit organization with which a director, or a director s spouse, has a relationship, impacts the director s independence.

Our general partner s board of directors has affirmatively determined that each of Ms. Peterson and Messrs. Krimbill and Parker is an independent director under the current listing standards of the New York Stock Exchange and our director independence standards. In so doing, the board of directors determined that each of these individuals met the bright line independence standards of the New York Stock Exchange. In addition, the board of directors considered transactions and relationships between each director and the Partnership Group, either directly or indirectly. The purpose of this review was to determine whether any such relationships or transactions were inconsistent with a determination that the director is independent. The board of directors considered the fact that Mr. Krimbill served as a director of Seminole Energy Services LLC until February 5, 2010, which is a customer and vendor to certain subsidiaries of us and Williams. The board of directors noted that, since Mr. Krimbill did not serve as an executive officer and does not own a significant amount of voting securities of Seminole Energy Services LLC, this relationship is not material. Accordingly, the board of directors of our general partner affirmatively determined that all of the directors mentioned above are independent. Because Messrs. Armstrong, Chappel, Malcolm, Rod J. Sailor (who served as a director of our general partner until February 17, 2010) and Wright are employees, officers and/or directors of Williams, they are not independent under these standards.

Ms. Peterson and Messrs. Krimbill and Parker do not serve as an executive officer of any non-profit organization to which the Partnership Group made contributions within any single year of the preceding three years that exceeded the greater of $1.0 million or 2% of such organization s consolidated gross revenues. Further, in accordance with our director independence standards, there were no discretionary contributions made by any member of the Partnership Group to a non-profit organization with which such director, or such director s spouse, has a relationship that impact the director s independence.

In addition, our general partner s board of directors determined that each of Ms. Peterson and Messrs. Krimbill and Parker, who constitute the members of the audit committee of the board of directors, meet the heightened independence requirements of the New York Stock Exchange for audit committee members.

Meeting Attendance and Preparation

Members of the board of directors of our general partner are expected to attend at least 75% of regular board meetings and meetings of the committees on which they serve, either in person or telephonically. In addition, directors are expected to be prepared for each meeting of the board by reviewing written materials distributed in advance.

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Executive Sessions of Non-Management Directors

Our general partner s non-management board members periodically meet outside the presence of our general partner s executive officers. The chairman of the audit committee serves as the presiding director for executive sessions of non-management board members. The current chairman of the audit committee and the presiding director is Ms. Alice M. Peterson.

Communications with Directors

Interested parties wishing to communicate with our general partner s non-management directors, individually or as a group, may do so by contacting our general partner s corporate secretary or the presiding director. The contact information is maintained on the investor relations/corporate governance page of our website at *http://www.williamslp.com.*

The current contact information is as follows:

Williams Partners L.P.
c/o Williams Partners GP LLC
One Williams Center, Suite 4700
Tulsa, Oklahoma 74172
Attn: Corporate Secretary

Williams Partners L.P.
c/o Williams Partners GP LLC
One Williams Center, Suite 4700
Tulsa, Oklahoma 74172
Attn: Presiding Director
E-mail: lafleur.browne@williams.com

Board Committees

The board of directors of our general partner has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934 and a conflicts committee. The following is a description of each of the committees and committee membership as of February 25, 2010.

Board Committee Membership

	Audit Committee	Conflicts Committee
H. Michael Krimbill	ü	ü
Bill Z. Parker	ü	
Alice M. Peterson		ü

ü = committee member

= chairperson

Audit Committee

Our general partner s board of directors has determined that all members of the audit committee meet the heightened independence requirements of the New York Stock Exchange for audit committee members and that all members are financially literate as defined by the rules of the New York Stock Exchange. The board of directors has further determined that Ms. Alice M. Peterson and Mr. H. Michael Krimbill qualify as audit committee financial experts as defined by the rules of the SEC. Biographical information for Ms. Peterson and Mr. Krimbill is set forth above. The audit committee is governed by a written charter adopted by the board of directors. For further information about the audit committee, please read the Report of the Audit Committee below and Principal Accountant Fees and Services.

Conflicts Committee

The conflicts committee of our general partner s board of directors reviews specific matters that the board believes may involve conflicts of interest. The conflicts committee determines if resolution of the conflict is fair and reasonable to us. The members of the

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conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates and must meet the independence and experience requirements established by the New York Stock Exchange and the Sarbanes-Oxley Act of 2002 and other federal securities laws. Any matters approved by the conflicts committee will be conclusively deemed fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe to us or our unitholders.

Code of Business Conduct and Ethics

Our general partner has adopted a code of business conduct and ethics for directors, officers and employees. We intend to disclose any amendments to or waivers of the code of business conduct and ethics on behalf of our general partner s chief executive officer, chief financial officer, controller and persons performing similar functions on our Internet website at *http://www.williamslp.com* under the Investor Relations caption, promptly following the date of any such amendment or waiver.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our general partner s executive officers and directors and persons who own more than 10% of a registered class of our equity securities to file with the SEC and the New York Stock Exchange reports of ownership of our securities and changes in reported ownership. Executive officers and directors of our general partner and greater than 10% unitholders are required to by SEC rules to furnish to us copies of all Section 16(a) reports that they file. Based solely on a review of reports furnished to our general partner, or written representations from reporting persons that all reportable transactions were reported, we believe that during the fiscal year ended December 31, 2009 our general partner s officers, our directors and our greater than 10% common unitholders filed all reports they were required to file under Section 16(a) on a timely basis.

Transfer Agent and Registrar

Computershare Trust Company, N.A. serves as registrar and transfer agent for our common units. Contact information for Computershare is as follows:

Computershare Trust Company, N.A.
P.O. Box 43069
Providence, Rhode Island 02940-3069
Phone: (781) 575-2879 or toll-free, (877) 498-8861
Hearing impaired: (800) 952-9245
Internet: www.computershare.com/investor
Send overnight mail to:
Computershare
250 Royall St.
Canton, Massachusetts 02021

REPORT OF THE AUDIT COMMITTEE

The audit committee oversees our financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls. The audit committee operates under a written charter approved by the board. The charter, among other things, provides that the audit committee has authority to appoint, retain, oversee and terminate when appropriate the independent auditor. In this context, the audit committee:

- reviewed and discussed the audited financial statements in this annual report on Form 10-K with management, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements;

- reviewed with Ernst & Young LLP, the independent auditors, who are responsible for expressing an opinion on the conformity of those audited financial statements with generally accepted accounting principles, their judgments as to the quality and acceptability of Williams Partners L.P. s accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards;

received the written disclosures and the letter from Ernst & Young LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding Ernst & Young LLP s communications with the audit committee concerning independence, and discussed with Ernst & Young LLP its independence;

discussed with Ernst & Young LLP the matters required to be discussed by the statement on Auditing Standards No. 61, as amended, as adopted by the Public Company Accounting Oversight Board in Rule 3200T;

discussed with Williams Partners L.P. s internal auditors and Ernst & Young LLP the overall scope and plans for their respective audits. The audit committee meets with the internal auditors and Ernst & Young LLP, with and without management present, to discuss the results of their examinations, their evaluations of Williams Partners L.P. s internal controls and the overall quality of Williams Partners L.P. s financial reporting; and

based on the foregoing reviews and discussions, recommended to the board of directors that the audited financial statements be included in the annual report on Form 10-K for the year ended December 31, 2009, for filing with the SEC.

This report has been furnished by the members of the audit committee of the board of directors:

Alice M. Peterson chairman

Bill Z. Parker

H. Michael Krimbill

The report of the audit committee in this report shall not be deemed incorporated by reference into any other filing by Williams Partners L.P. under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under such acts.

Item 11. ***Executive Compensation***

Compensation Discussion and Analysis

We and our general partner, Williams Partners GP LLC, were formed in February 2005. We are managed by the executive officers of our general partner who are also executive officers of Williams. Neither we nor our general partner have a compensation committee. The executive officers of our general partner are compensated directly by Williams. All decisions as to the compensation of the executive officers of our general partner who are involved in our management are made by the compensation committee of Williams. Therefore, we do not have any policies or programs relating to compensation of the executive officers of our general partner and we make no decisions relating to such compensation. None of the executive officers of our general partner have employment agreements with us or are otherwise specifically compensated for their service as an executive officer of our general partner. A full discussion of the policies and programs of the compensation committee of Williams will be set forth in the proxy statement for Williams 2010 annual meeting of stockholders which will be available upon its filing on the SEC s website at *http://www.sec.gov* and on Williams website at *http://www.williams.com* under the heading Investors SEC Filings. We reimburse our general partner for direct and indirect general and administrative expenses attributable to our management (which expenses include the share of the compensation paid to the executive officers of our general partner attributable to the time they spend managing our business). Please read Certain Relationships and Related Transactions, and Director Independence Reimbursement of Expenses of Our General Partner for more information regarding this arrangement.

Executive Compensation

Information regarding the portion of Mr. Armstrong s, Mr. Bender s, Mr. Chappel s and Mr. Malcolm s compensation and employment-related expenses allocable to us may be found in this filing under the heading Certain Relationships and Related Transactions, and Director Independence Reimbursement of Expenses of Our General Partner.

Further information regarding the compensation of our principal executive officer, Steven J. Malcolm, who also serves as the chairman, president and chief executive officer of Williams, our principal financial officer, Donald R.

Chappel, who also serves as the

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chief financial officer of Williams, Alan S. Armstrong, our senior vice president midstream, who also serves as a senior vice president of Williams, and Phillip D. Wright, who was appointed our senior vice president gas pipeline on February 17, 2010, who also serves as a senior vice president of Williams, will be set forth in the proxy statement for Williams 2010 annual meeting of stockholders which will be available upon its filing on the SEC s website at *http://www.sec.gov* and on Williams website at *http:/www.williams.com* under the heading Investors SEC Filings.

Compensation Committee Interlocks and Insider Participation

As previously discussed, our general partner s board of directors is not required to maintain, and does not maintain, a compensation committee. Steven J. Malcolm, our general partner s chief executive officer and chairman of the board of directors serves as the chairman of the board and chief executive officer of Williams. Alan S. Armstrong, Donald R. Chappel and Phillip D. Wright, who are directors of our general partner, are also executive officers of Williams. Rodney J. Sailor, who was a director of our general partner until February 17, 2010, is also a non-executive officer and an employee of Williams. However, all compensation decisions with respect to each of these persons are made by Williams and none of these individuals receive any compensation directly from us or our general partner. Please read Certain Relationships and Related Transactions, and Director Independence below for information about relationships among us, our general partner and Williams.

Board Report on Compensation

Neither we nor our general partner has a compensation committee. The board of directors of our general partner has reviewed and discussed the Compensation Discussion and Analysis set forth above and based on this review and discussion has approved it for inclusion in this Form 10-K.

The Board of Directors of Williams Partners GP LLC:
Alan S. Armstrong, Donald R. Chappel,
H. Michael Krimbill, Steven J. Malcolm
Bill Z. Parker, Alice M. Peterson,
Phillip D. Wright

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Compensation of Directors

We are managed by the board of directors of our general partner. Members of the board of directors who are also officers or employees of Williams or an affiliate of us or Williams do not receive additional compensation for serving on the board of directors. Please read Certain Relationships and Related Transactions, and Director Independence Reimbursement of Expenses of Our General Partner for information about how we reimburse our general partner for direct and indirect general and administrative expenses attributable to our management. Non-employees directors receive a bi-annual compensation package consisting of the following, which amounts are paid on August 22 and February 1: (a) $37,500 cash retainer; and (b) $2,500 cash each for service on the conflicts or audit committees of the board of directors. If a non-employee director s service on the board of directors commences between December 1 and January 31 or between February 2 and August 21, the non-employee director will receive a prorated bi-annual compensation package. In addition to the bi-annual compensation package, each non-employee director will receive a one-time cash payment of $25,000 on the date of first election to the board of directors. Also, each non-employee director serving as a member of the conflicts committee of the board of directors receives $1,250 cash for each conflicts committee meeting attended by such director. Fees for attendance at meetings of the conflicts committee are paid on August 22 and February 1 of each year for meetings held during the preceding months. Each non-employee director is also reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees. Each director will be fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law. We also reimburse non-employee directors for the costs of education programs relevant to their duties as board members.

For their service, non-management directors received the following compensation in 2009:

Director Compensation Fiscal Year 2009

Name	Fees Earned or Paid in Cash (1)	Unit Awards (2)	Option Awards	Non-Equity Incentive Plan Compensation	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation	Total
H. Michael Krimbill	$ 56,250	$ 6,664					$ 62,914
Bill Z. Parker	$ 56,250	$ 6,664					$ 62,914
Alice M. Peterson	$ 56,250	$ 6,664					$ 62,914

(1) In May 2009, our director compensation policy was revised to include two payments for the annual director compensation package. As a result, the table

above reflects only one bi-annual cash payment made on August 22. Fees earned for attending 11 conflicts committee meetings in 2009 are also reflected in this column.

(2) Prior to 2009, non-employee directors received a portion of their compensation in the form of restricted units. The last grant of restricted units occurred in August of 2008 and the expense related to the grant is reflected in this column. Restricted units awarded to non-employee directors in 2008 were granted under the Williams Partners GP LLC Long-Term Incentive Plan and vested 180 days after the date of grant. Cash distributions were paid on these restricted units.

Long-Term Incentive Plan

Our general partner adopted the Williams Partners GP LLC Long-Term Incentive Plan for employees, consultants and directors of our general partner and employees and consultants of its affiliates who perform services for our general partner or its affiliates. To date, the only grants under the plan have been grants of restricted units to directors who are not officers or employees of us or our affiliates. In 2006, the board of directors of our general partner dissolved its compensation committee. The only function performed by the committee prior to its dissolution was to administer the Williams Partners GP LLC Long-Term Incentive Plan. Accordingly, also in 2006, the board of directors approved an amendment to the long-term incentive plan to allow the full board of directors to administer the plan. On December 2, 2008, the board of directors of our general partner approved an amendment to the long-term incentive plan to comply with Section 409A of the Internal Revenue Code of 1986 and its relevant regulations. The long-term incentive plan consists of four components: restricted units, phantom units, unit options and unit appreciation rights. The long-term incentive plan currently permits the grant of awards covering an aggregate of 700,000 units. There were no grants or awards under the long-term incentive plan in 2009.

Our general partner s board of directors, in its discretion may terminate, suspend or discontinue the long-term incentive plan at any time with respect to any award that has not yet been granted. Our general partner s board of directors also has the right to alter or

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amend the long-term incentive plan or any part of the plan from time to time, including increasing the number of units that may be granted subject to unitholder approval as required by the exchange upon which the common units are listed at that time. However, except for specific adjustment rights detailed in the plan, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The following table sets forth the beneficial ownership of common units of Williams Partners L.P. that are owned by:

each person known by us to be a beneficial owner of more than 5% of the units;

each of the directors of our general partner;

each of the executive officers of our general partner; and

all directors and executive officers of our general partner as a group.

Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Total Common Units Beneficially Owned	Class C Units Beneficially Owned	Percentage of Class C Units Beneficially Owned	Percentage of Total Units Beneficially Owned
The Williams Companies, Inc.(a)	11,613,527	22.00%	203,000,000	100%	83.91%
Williams Gas Pipeline Company, LLC(a)			119,932,400	59.08%	46.89%
Williams Energy Services, LLC(a)	8,787,149	16.65%	83,067,600	40.92%	35.91%
Williams Partners GP LLC(a)	3,363,527	6.37%			1.32%
Williams Energy, L.L.C.(a)	2,952,233	5.59%			1.15%
MAPCO Inc.(a)	2,952,233	5.59%			1.15%
Williams Partners Holdings LLC(a)	2,826,378	5.36%			1.11%
Kayne Anderson Capital Advisors, L.P./Richard A. Kayne(b)	4,459,179	8.45%			1.74%
Alan S. Armstrong(c)	20,000	*			*
James J. Bender(d)	10,000	*			*
Donald R. Chappel	10,000	*			*
H. Michael Krimbill	57,151	*			*
Steven J. Malcolm(e)	25,100	*			*
Bill Z. Parker	9,524	*			*
Alice M. Peterson	4,524	*			*
Phillip D. Wright	4,425	*			*
All directors and executive officers as a group (eight persons)	140,724	*			*

Percentage of common units beneficially owned is based on 52,777,452 common units outstanding. Percentage of Class C units owned is based on 203,000,000 Class C units outstanding. Percentage of total units beneficially owned is based on 255,777,452 common units and Class C units outstanding.

Our general partner, Williams Partners GP LLC, also owns all of our 2% general partner interest and IDRs.

* Less than 1%.

(a) As noted in the Schedule 13D/A filed with the SEC on February 19, 2010, The Williams Companies, Inc. is the ultimate parent company of Williams Energy Services, LLC, Williams Partners GP LLC, Williams Energy, L.L.C., Williams Discovery Pipeline LLC, Williams Partners Holdings LLC, Williams Gas Pipeline LLC and Williams Gulfstream Pipeline LLC and may, therefore, be deemed to beneficially own the units held by each of these companies. The Williams Companies, Inc. s common stock is

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listed on the New York Stock Exchange under the symbol WMB. The Williams Companies, Inc. files information with or furnishes information to, the Securities and Exchange Commission pursuant to the information requirements of the Securities Exchange Act of 1934 (the Act). WGP Gulfstream Pipeline Company, L.L.C. is the record holder of 4,242,700 Class C units. Williams Gas Pipeline Company LLC is the record owner of 115,689,700 Class C units, and, as the sole member of WGP Gulfstream Pipeline Company, L.L.C., may, pursuant to Rule 13d-3, be deemed to beneficially own the Class C units owned by WGP Gulfstream Pipeline Company, L.L.C. Williams Discovery

Pipeline LLC is the record holder of 1,425,466 common units. Williams Partners Holdings LLC is the record holder of 2,826,378 common units. Williams Energy, L.L.C. is the record holder of 2,952,233 common units. Williams Partners GP LLC is the record holder of 3,363,527 common units. Williams Energy Services, LLC is the record owner of 1,045,923 common units and, as the sole stockholder of MAPCO Inc. and the sole member of Williams Discovery Pipeline LLC and Williams Partners GP LLC, may, pursuant to Rule 13d-3, be deemed to beneficially own the units beneficially owned by MAPCO Inc., Williams Discovery Pipeline LLC and Williams Partners GP LLC. MAPCO

Inc., as the sole member of Williams Energy, L.L.C., may, pursuant to Rule 13d-3, be deemed to beneficially own the units held by Williams Energy, L.L.C. The address of these companies is One Williams Center, Tulsa, Oklahoma 74172.

(b) Based solely on the Schedule 13G/A filed with the SEC on February 12, 2010, Kayne Anderson Capital Advisors, L.P. (Kayne Capital), an investment advisor registered under Section 203 of the Investment Advisors Act of 1940, and Richard A. Kayne, a U.S. citizen, may be deemed to be the beneficial owner of units owned by investment accounts (investment limited partnerships, a registered investment company and institutional accounts) managed, with discretion to purchase or sell securities, by Kayne Capital. The Schedule 13G notes that Mr. Kayne is the controlling shareholder of the corporate owner of Kayne Anderson Investment Management, Inc., the general partner of Kayne Capital, and is also a limited partner of each of the limited partnerships and a shareholder of the registered investment company. The address of Kayne Capital and Mr. Kayne is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067.

(c) Mr. Armstrong is the trustee of The Shelly Stone Armstrong Trust dated August 10, 2004, and has the right to receive or the power to direct the receipt of dividends from, or the proceeds from the sale of, 10,000 common units that are held by the trust.

(d) Represents units beneficially owned by Mr. Bender that are held by the James J. Bender Revocable Trust.

(e) Represents units beneficially owned by Mr. Malcolm that are held by the Steven J. Malcolm Revocable Trust.

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The following table sets forth, as of February 1, 2010, the number of shares of common stock of The Williams Companies, Inc. owned by each of the executive officers and directors of our general partner and all directors and executive officers of our general partner as a group.

Name of Beneficial Owner	Shares of Common Stock Owned Directly or Indirectly(a)	Shares Underlying Options Exercisable Within 60 Days(b)	Total	Percent of Class
Alan S. Armstrong	224,996	423,976	648,972	*
James J. Bender	190,585	192,455	383,040	*
Donald R. Chappel	348,550	491,051	839,601	*
Steven J. Malcolm	1,082,520	2,204,650	3,287,170	*
Phillip D. Wright	350,569	545,552	896,121	*
Bill Z. Parker				
Alice M. Peterson				
H. Michael Krimbill	10,000		10,000	*
All directors and executive officers as a group (eight persons)	2,207,220	3,857,684	6,064,904	*

* Less than 1%.

(a) Includes shares held under the terms of incentive and investment plans as follows: Mr. Armstrong, 15 shares in The Williams Companies Investment Plus Plan, 152,871 restricted stock units and 72,110 beneficially owned shares; Mr. Bender, 2,800 shares owned by children, 130,927 restricted stock units and 56,858 beneficially owned shares; Mr. Chappel, 206,023 restricted stock units and 142,527 beneficially owned shares; Mr. Malcolm, 47,998 shares in The Williams Companies Investment Plus Plan, 370,593 restricted stock units and 663,929 beneficially owned shares; and Mr. Wright, 15,857 shares in The Williams Investment Plus Plan, 152,871 restricted stock units and 181,841 beneficially owned shares. Restricted stock units do not provide the holder with voting or investment power.

(b) The shares indicated represent stock options granted under Williams current or previous stock option plans, which are currently exercisable or which will become exercisable within 60 days of February 1, 2009. Shares subject to options cannot be voted.

The following table sets forth, as of February 1, 2010, the number of common units of Williams Pipeline Partners L.P. owned by each of the executive officers and directors of our general partner and all directors and executive officers of our general partner as a group.

Name of Beneficial Owner	**Common Units Beneficially Owned**	**Percentage of Common Units Beneficially Owned**
Alan S. Armstrong		
James J. Bender	10,000	*
Donald R. Chappel	10,000	*
Steven J. Malcolm	10,000	*
Phillip D. Wright	10,100	*
Bill Z. Parker		
Alice M. Peterson		
H. Michael Krimbill		
All directors and executive officers as a group (eight persons)	40,100	*

* Less than 1%.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information concerning common units that were potentially subject to issuance under the Williams Partners GP LLC Long-Term Incentive Plan as of December 31, 2010. For more information about this plan, which did not require

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approval by our limited partners, please read Note 15, Long-Term Incentive Plan, of our Notes to Consolidated Financial Statements and Executive Compensation Long-Term Incentive Plan.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plan (Excluding Securities Reflected in Column(a)) (c)
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders.			686,597
Total			686,597

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Transactions with Related Persons

As of February 18, 2010, our general partner and its affiliates own 11,613,527 common units and 203,000,000 Class C units. The Class C units are not publicly traded. Our Class C units are identical to our common units except that the quarterly distribution they receive with respect to first quarter 2010 will be prorated to reflect the fact that the Class C units were not outstanding during the full quarterly period. The Class C units will automatically convert into common units following the record date for the distribution with respect to the first quarter in 2010. Williams ownership in the common units and Class C units represents an approximate 82% limited partner interest in us.

Williams also indirectly owns 100% of our general partner, which allows it to control us. Certain officers and directors of our general partner also serve as officers and/or directors of Williams. In addition, our general partner owns a 2% general partner interest and incentive distribution rights in us.

In addition to the related transactions and relationships discussed below, information about such transactions and relationships is included in Note 6, Related Party Transactions, of our Notes to Consolidated Financial Statements and is incorporated herein by reference in its entirety.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments made or to be made by us to our general partner and its affiliates, which include Williams, in connection with the ongoing operation and liquidation of Williams Partners L.P. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

	Operational Stage
Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 98% to unitholders, including our general partner and its affiliates as holders of an aggregate of 11,613,527 common units, 203,000,000 Class C units and the remaining 2% to our general partner.

	In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target level. We refer to the rights to the increasing distributions as incentive distribution rights. For further information about distributions, please read Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.
Reimbursement of expenses to our general partner	Our general partner does not receive a management fee or other compensation for

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	Operational Stage
and its affiliates	the management of our partnership. Our general partner and its affiliates are reimbursed, however, for all direct and indirect expenses incurred on our behalf. Our general partner determines the amount of these expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
	Liquidation Stage
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Reimbursement of Expenses of Our General Partner

Our general partner does not receive any management fee or other compensation for its management of our business. However, we reimburse our general partner for expenses incurred on our behalf, including expenses incurred in compensating employees of an affiliate of our general partner who perform services on our behalf. These expenses include all allocable expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. There is no minimum or maximum amount that may be paid or reimbursed to our general partner for expenses incurred on our behalf, except that pursuant to an omnibus agreement, Williams provided a partial credit for general and administrative expenses that we incurred for a period of five years following our initial public offering (IPO) of common units in August 2005. Please read Initial Omnibus Agreement below for more information.

For the fiscal year ended December 31, 2009, our general partner allocated $219,546 of salary and non-equity incentive plan compensation expense to us for Steven J. Malcolm, the chairman of the board and chief executive officer of our general partner, $108,733 of salary and non-equity incentive plan compensation expense to us for Donald R. Chappel, the chief financial officer of our general partner, $289,160 of salary and non-equity incentive plan compensation expense to us for Alan S. Armstrong, the senior vice president-midstream of our general partner, $79,539 of salary and non-equity incentive plan compensation expense to us for James J. Bender, the general counsel of our general partner and $55,882 of salary and non-equity incentive plan compensation expense to us for Rodney J. Sailor, who served as a director of our general partner until February 17, 2010 and is also a non-executive officer and employee of Williams. Our general partner also allocated to us $238,302 for Mr. Malcolm, $107,959 for Mr. Chappel, $286,089 for Mr. Armstrong, $70,438 for Mr. Bender and $33,835 for Mr. Sailor, which expenses are attributable to additional compensation paid to each of them and other employment-related expenses, including Williams restricted stock unit and stock option awards, retirement plans, health and welfare plans, employer-related payroll taxes, matching contributions made under a Williams 401(k) plan and premiums for life insurance. Our general partner also allocated to us a portion of Williams expenses related to perquisites for each of Messrs. Malcolm, Chappel, Bender and Armstrong, which allocation did not exceed $10,000 for any of these persons. The foregoing amounts exclude expenses allocated by Williams to Discovery, Wamsutter and the Contributed Entities. No awards were granted to our general partner s executive officers under the Williams Partners GP LLC Long-Term Incentive Plan in 2008 or 2009. The total compensation received by Mr. Malcolm, the chairman of the board and chief executive officer of our general partner who is also the chairman, president and chief executive officer of Williams, Mr. Chappel, the chief financial officer of our general partner who is also the chief financial officer of Williams, and Messrs. Armstrong and Wright, senior vice presidents of our general partner who are also senior vice presidents of Williams, will be set forth in the proxy statement for Williams 2010 annual meeting of stockholders which will be available upon its filing on the SEC s website at *http://www.sec.gov* and on Williams website at *http://www.williams.com* under the heading Investors SEC

Filings.

For the year ended December 31, 2009, we incurred approximately $95.5 million in total operating and maintenance and general and administrative expenses from Williams incurred on our behalf pursuant to the partnership agreement.

Initial Omnibus Agreement

Upon the closing of our IPO, we entered into an omnibus agreement with Williams and its affiliates that was not the result of arm s-length negotiations. The omnibus agreement governs our relationship with Williams regarding the following matters:

- reimbursement of certain general and administrative expenses;

indemnification for certain environmental liabilities, tax liabilities and right-of-way defects;

reimbursement for certain expenditures; and

a license for the use of certain software and intellectual property.

General and Administrative Expenses

In our initial omnibus agreement, Williams provided us with a five-year partial credit for general and administrative (G&A) expenses incurred on our behalf. In 2007, 2008 and 2009, the amounts of the G&A credit were $2.4 million, $1.6 million and $0.8 million, respectively. After 2009, we will no longer receive any credit and will be required to reimburse Williams for all of the general and administrative expenses incurred on our behalf.

In 2009, our omnibus agreement with Williams was amended to increase the aggregate amount of the credit we could receive related to certain general and administrative expenses for 2009. Consequently, for 2009, Williams provided an additional $1.0 million credit, in addition to the $0.8 million annual credit previously provided under the original omnibus agreement. We recorded total general and administrative expenses (including those expenses that are subject to the credit by Williams) as an expense, and we recorded the credits as capital contributions from Williams. Accordingly, our net income did not reflect the benefit of the credit received from Williams. However, the costs subject to this credit will be allocated entirely to our general partner. As a result, the net income allocated to limited partners on a per-unit basis reflected the benefit of this credit. We expect to receive an additional $0.8 million credit in 2010 from Williams under the 2009 omnibus amendment.

Indemnification for Environmental and Related Liabilities

In our initial omnibus agreement, Williams agreed to indemnify us after the closing of our IPO against certain environmental and related liabilities arising out of or associated with the operation of the assets before the closing date of our initial public offering. These liabilities include both known and unknown environmental and related liabilities, such as remediation costs associated with the KDHE Consent Orders and certain NGLs associated with our Conway storage facilities.

Williams will not be required to indemnify us for any project management or monitoring costs. This indemnification obligation terminated in August 2008, except in the case of the remediation costs associated with the KDHE Consent Orders which will survive for an unlimited period of time. There is an aggregate cap of $14.0 million on the amount of indemnity coverage. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Environmental. In addition, we are not entitled to indemnification until the aggregate amounts of claims exceed $250,000. Liabilities resulting from a change of law after the closing of our IPO are excluded from the environmental indemnity by Williams for the unknown environmental liabilities.

Williams will also indemnify us for liabilities related to certain income tax liabilities attributable to the operation of the assets contributed to us in connection with our IPO prior to the time they were contributed.

For the year ended December 31, 2009, Williams indemnified us $0.4 million for Conway s KDHE-related compliance. Including 2009, Williams has indemnified us for an aggregate of $7.1 million pursuant to the omnibus agreement.

Reimbursement for Certain Expenditures Attributable to Discovery

Williams agreed to reimburse us for certain capital expenditures, subject to limits, including certain excess capital expenditures in connection with Discovery s Tahiti pipeline lateral expansion project. The initial expected cost of the Tahiti pipeline lateral expansion project was approximately $69.5 million, of which our 40% share, included in the IPO and reimbursed under the omnibus agreement, was approximately $27.8 million. Williams agreed to reimburse us for the excess (up to $3.4 million) of the total cost of the Tahiti pipeline lateral expansion project above the amount of the required escrow deposit ($24.4 million) attributable to our 40% interest in Discovery, included in the IPO and reimbursed under the omnibus agreement. The cost of the Tahiti pipeline lateral expansion project, which was completed in second quarter 2009, was $76.2 million. Williams reimbursed us $1.8 million in 2009 and an aggregate $3.4 million over the life of the project, for Discovery s capital calls related to this project.

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Intellectual Property License

Williams and its affiliates granted a license to us for the use of certain marks, including our logo, for as long as Williams controls our general partner, at no charge.

Amendments

The omnibus agreement may not be amended without the prior approval of the conflicts committee if the proposed amendment will, in the reasonable discretion of our general partner, adversely affect holders of our common units. Please read the discussion of the amendment related to the Dropdown discussed below in Amendment to our Limited Partnership Agreement

Competition

Williams is not restricted under the omnibus agreement from competing with us. Williams may acquire, construct or dispose of additional midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Credit Facilities

Working Capital Facility

In February 2010, we established a new $1.75 billion senior unsecured revolving three-year credit facility (New Credit Facility) with Citibank, N.A. as administrative agent and Transco and Northwest Pipeline as co-borrowers. After this transaction, we terminated our $20.0 million working capital revolving credit facility with Williams as the lender. As of December 31, 2009, we had no outstanding borrowings under the revolving credit facility with Williams.

Wamsutter Credit Facility

Pursuant to the Dropdown, the $20.0 million revolving credit facility that Wamsutter had with Williams as the lender was terminated. As of December 31, 2009, Wamsutter had no outstanding borrowings under the credit facility.

Wamsutter Limited Liability Company Agreement

In connection with the Wamsutter Ownership Interests in December 2007, we and an affiliate of Williams entered into an amended and restated limited liability company agreement for Wamsutter. This agreement governed the ownership and management of Wamsutter and provided for quarterly distributions of available cash to the members.

Additionally, Wamsutter s limited liability company agreement appointed Williams as the operator. As such, effective December 1, 2007 Williams was reimbursed on a monthly basis for all direct and indirect expenses it incurred on behalf of Wamsutter including Wamsutter s allocable share of general and administrative costs.

In connection with the closing of the Dropdown, the Wamsutter Limited Liability Company Agreement was amended to reflect that we are the sole member.

Discovery Operating and Maintenance Agreements

Discovery is party to three operating and maintenance agreements with Williams: one relating to Discovery Producer Services LLC, one relating to Discovery Gas Transmission LLC and another relating to the Paradis Fractionation Facility and the Larose Gas Processing Plant. Under these agreements, Discovery is required to reimburse Williams for direct payroll and employee benefit costs incurred on Discovery s behalf. Most costs for materials, services and other charges are third-party charges and are invoiced directly to Discovery. Discovery is required to pay Williams a monthly operation and management fee to cover the cost of accounting services, computer systems and management services provided to Discovery under each of these agreements. Discovery also pays Williams a project management fee to cover the cost of managing capital projects. This fee is determined on a project by project basis.

For the year ended December 31, 2009, Discovery reimbursed Williams $5.4 million for direct payroll and employee benefit costs, as well as $0.3 million for capitalized labor costs, pursuant to the operating and maintenance agreements and paid Williams

$6.0 million for operation and management fees, as well as a $0.3 million fee for managing capitalized projects, pursuant to the operating and maintenance agreements.

Natural Gas and NGL Purchasing Contracts

Certain subsidiaries of Williams market substantially all of the NGLs and excess natural gas to which Wamsutter and Discovery, our Conway fractionation and storage facility and our Four Corners system control. Wamsutter and Discovery, our Conway fractionation and storage facility and our Four Corners system conduct the sales of the NGLs and excess natural gas to which they control pursuant to base contracts for sale and purchase of natural gas and a NGLs master purchase, sale and exchange agreement. These agreements contain the general terms and conditions governing the transactions such as apportionment of taxes, timing and manner of payment, choice of law and confidentiality. Historically, the sales of natural gas and NGLs to which Wamsutter and Discovery, our Conway fractionation and storage facility and our Four Corners system control have been conducted at market prices with certain subsidiaries of Williams as the counter parties. Additionally, Wamsutter and Discovery, our Conway fractionation and storage facility and our Four Corners system may purchase natural gas to meet their fuel and other requirements and our Conway storage facility may purchase NGLs as needed to maintain inventory balances.

For the year ended December 31, 2009, we sold $167.5 million of products to subsidiaries of Williams that purchase substantially all of the NGLs and excess natural gas to which our Conway fractionation and storage facility and our Four Corners system take title based on market pricing, Wamsutter sold $95.7 million of products to subsidiaries of Williams that purchase substantially all of the NGLs and excess natural gas to which Wamsutter takes title based on market pricing and Discovery sold $114.7 million of products to subsidiaries of Williams that purchase substantially all of the NGLs and excess natural gas to which Discovery controls based on market pricing. Following the Dropdown, we will consolidate Williams NGL Marketing LLC (WNGLM), the entity which purchased the NGLs from us. As a result, the majority of our affiliate product sales will be eliminated against the related affiliate product cost recorded by WNGLM.

In 2009, we entered into financial swap contracts with Williams Gas Marketing, Inc. (WGM), an affiliate of Williams, based on market rates at the time of execution, to hedge 32 million gallons of forecasted NGL sales for the second half of 2009 with a range of fixed prices of $0.465 per gallon to $1.404 per gallon depending on the specific product and 4.3 million gallons of forecasted 2010 NGL sales with a fixed price of $1.103 per gallon. In 2009, Wamsutter entered into financial swap contracts with WGM, based on market rates at the time of execution, to hedge 21 million gallons of forecasted NGL sales for the second half of 2009 with a range of fixed prices of $0.465 per gallon to $0.923 per gallon depending on the specific product.

Gathering, Processing and Treating Contracts

We have a gas gathering and treating contract and a gas gathering and processing contract with an affiliate of Williams. Pursuant to the gas gathering and treating contract, our Four Corners system gathers and treats coal seam gas delivered by the affiliate to our Four Corners gathering systems. The term of this agreement expires on December 31, 2022, but will continue thereafter on a year-to-year basis subject to termination by either party giving at least six months written notice of termination prior to the expiration of each one year period.

Pursuant to gas gathering and processing contracts, our Four Corners system gathers and processes conventional and coal seam gas delivered by the affiliate to our Four Corners gathering systems. The primary terms of these agreements ended on March 1, 2004, but continue to remain in effect on a year-to-year basis subject to termination by either party giving at least three months written notice of termination prior to the expiration of each one-year period.

Revenues recognized pursuant to these contracts totaled $44.0 million in 2009.

Natural Gas Purchases

We, Wamsutter and Discovery purchase natural gas primarily for fuel and shrink replacement from WGM, an affiliate of Williams. These purchases are made at current market prices. For Four Corners, we purchased approximately $50.4 million of natural gas from WGM during 2009. Wamsutter purchased approximately $20.5 million and Discovery purchased approximately $22.9 million of natural gas for fuel and shrink replacement from WGM during 2009.

Four Corners uses waste heat from a co-generation plant located adjacent to the Milagro treating plant. The co-generation plant is owned by an affiliate of Williams, Williams Flexible Generation, LLC. Waste heat is required for the natural gas treating process,

which occurs at Milagro. The charge to us for the waste heat is based on the natural gas needed to generate this waste heat. We purchase this natural gas from WGM. Included in the $50.4 million presented in the immediately preceding paragraph is $10.5 million of natural gas purchases made to pursuant to this arrangement. These purchases are generally made at market prices at the time of the purchase. Following the Dropdown, we will consolidate Williams Flexible Generation, LLC. As a result, our cost of waste heat will be eliminated against the related revenue recorded by this entity.

For the year ended December 31, 2009 we purchased a gross amount of $9.3 million of natural gas for our Conway fractionator from WGM.

In 2009, we entered into fixed price natural gas purchase contracts with WGM, based on market rates at the time of execution, to hedge a range of 7 BBtu/d to 14.5 BBtu/d forecasted natural gas purchases for shrink replacement at a range of fixed prices from $2.95 to $5.05 per MMBtu for the last half of 2009. In 2009, Wamsutter entered into fixed price natural gas purchase contracts with WGM, based on market rates at the time of execution, to hedge a range of 5 BBtu/d to 10 BBtu/d forecasted natural gas purchases for shrink replacement costs at a range of fixed prices from $2.91 to $3.48 per MMBtu for the last half of 2009.

Balancing Services Agreement

We maintain a balancing services contract with WGM, an affiliate of Williams. Pursuant to this agreement, WGM balances deliveries of natural gas processed by us between certain points on our Four Corners gathering system. We determine on a daily basis the volumes of natural gas to be moved between gathering systems at established interconnect points to optimize flow, an activity referred to as crosshauling. Under the balancing services contract, WGM purchases gas for delivery to customers at certain plant outlets and sells such volumes at other designated plant outlets to implement the crosshaul. These purchase and sales transactions are conducted for us by WGM at current market prices. Historically, WGM has not charged a fee for providing this service, but has occasionally benefited from price differentials that historically existed from time to time between the designated plant outlets. The revenues and costs related to the purchases and sales pursuant to this arrangement have historically tended to offset each other. The term of this agreement will expire upon six months or more written notice of termination from either party. To date, neither party has provided six months notice to terminate the agreement.

Summary of Other Transactions with Williams

For the year ended December 31, 2009:

- we distributed $39.7 million to affiliates of Williams as quarterly distributions on their common units, subordinated units, 2% general partner interest and incentive distribution rights for the fourth quarter 2008 distribution period which was paid in 2009. In 2009, Williams waived the incentive distribution rights (IDRs) related to the 2009 distribution periods. These IDRs represented $29.0 million, on an annual basis.

- we purchased $8.7 million of NGLs to replenish deficit product positions from WNGLM based on market pricing. Following the Dropdown, we will consolidate WNGLM. As a result, our affiliate product costs will be eliminated against the related affiliate product sales recorded by WNGLM.

ADDITIONAL TRANSACTIONS WITH RELATED PERSONS ASSOCIATED WITH THE DROPDOWN

Agreements Related to the Dropdown

We, our general partner, our operating company, other affiliates of Williams and Williams entered into certain agreements that effected our acquisition of the Contributed Entities, and the application of the proceeds of the offering of notes in connection with our acquisition of the Contributed Entities. These agreements are the result of arm s-length negotiations between Williams and the conflicts committee of the board of directors of our general partner, which is composed solely of independent directors unaffiliated with Williams.

Contribution Agreement

On February 17, 2010, we closed the transaction associated with the Contribution Agreement with our general partner, our operating company and certain subsidiaries of Williams, pursuant to which Williams contributed to us the ownership interests in the

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entities that make up Williams Gas Pipeline and Midstream Gas & Liquids business segments, to the extent not already owned by us, including Williams limited and general partner interests in Williams Pipeline Partners L.P. (WMZ), but excluding Williams Canadian, Venezuelan and olefin operations and 25.5% of Gulfstream Natural Gas System, L.L.C. (Gulfstream). Such entities are hereafter referred to as the Contributed Entities. The transactions associated with the Contribution Agreement are referred to as the Dropdown. Please read Business and Properties Recent Events the Dropdown for more information about the Contribution Agreement and the transactions related to this agreement.

Conveyance, Contribution and Assumption Agreement

In connection with the closing of the Dropdown, the parties to the Contribution Agreement entered into a conveyance, contribution and assumption agreement. This conveyance, contribution and assumption agreement effected the contribution of the ownership interests in the Contributed Entities to us and further transferred such ownership interests from us to our operating company.

Transco Administrative Services Agreement

In connection with the closing of the Dropdown, Transco entered into an administrative services agreement with Transco Pipeline Services Company LLC, a subsidiary of Williams (Transco Pipeline Services), pursuant to which Transco Pipeline Services will provide personnel, facilities, goods, and equipment not otherwise provided by Transco necessary to operate Transco s businesses. In return, Transco reimburses Transco Pipeline Services for all direct and indirect expenses Transco Pipeline Services incurs or payments it makes (including salary, bonus, incentive compensation, and benefits) in connection with these services.

Northwest Pipeline Administrative Services Agreement

Prior to the closing of the Dropdown, Northwest entered into an administrative services agreement with Northwest Pipeline Services LLC, a wholly-owned subsidiary of Williams, to provide services that Northwest determines may be reasonable and necessary to operate its business, including employees, accounting, information technology, company development, operations, administration, insurance, risk management, tax, audit, finance, land, marketing, legal, and engineering, which services may be expanded, modified or reduced from time to time as agreed upon by the parties.

Secondment Agreement

In connection with the closing of the Dropdown, we, our general partner and Williams entered into a secondment agreement pursuant to which Williams agreed to cause its affiliates to provide personnel necessary to operate, manage, maintain and report the operating results of certain assets owned by one of our midstream entities. During the period that such personnel are providing such services, they are subject to the direction, supervision and control of our general partner. Our general partner is responsible for the costs and expenses related to such services, which are reimbursed in accordance with our partnership agreement.

Dropdown Omnibus Agreement

In connection with the closing of the Dropdown, we entered into an omnibus agreement with Williams. Pursuant to this omnibus agreement, Williams is obligated to indemnify us from and against or reimburse us for (i) amounts incurred by us or our subsidiaries for repair or abandonment costs for damages to certain facilities caused by Hurricane Ike, up to a maximum of $10,000,000, (ii) maintenance capital expenditure amounts incurred by us or our subsidiaries in respect of certain U.S. Department of Transportation projects, up to a maximum aggregate amount of $50,000,000, and (iii) an amount based on the amortization over time of deferred revenue amounts that relate to cash payments received prior to the closing of the Dropdown for services to be rendered by us in the future at the Devils Tower floating production platform located in Mississippi Canyon Block 773. In addition, we are obligated to pay to Williams the proceeds of certain sales of natural gas recovered from the Hester storage field pursuant to the FERC order dated March 7, 2008, approving a settlement agreement in Docket No. RP06-569.

Limited Call Right Forbearance Agreement

In connection with the closing of the Dropdown, we entered into a limited call right forbearance agreement with our general partner. Pursuant to this forbearance agreement, our general partner agreed to forbear exercising a right in certain circumstances that is granted to it under our partnership agreement. Currently, if our general partner and its affiliates hold more than 80% of our common limited partner units, our general partner has the right to purchase all of the remaining common limited partner units. In this forbearance agreement, our general partner agreed not to exercise this right unless it and its affiliates hold more than 85% of our common limited partner units. This forbearance agreement will terminate when the ownership by our general partner and its affiliates of our common limited partner units decreases below 75% (assuming the full conversion of Class C units that are held by our general partner and its affiliates).

Amendment to our Limited Partnership Agreement

In connection with the closing of the Dropdown, our general partner entered into an amendment to our partnership agreement. Pursuant to this amendment, our partnership agreement was amended to (i) authorize the issuance of the Class C units that will comprise part of the consideration for the Dropdown and to make certain other changes in connection with the authorization of the issuance of the Class C units, (ii) provide for the proration of distributions, with respect to the first fiscal quarter in which the Class C units and the additional general partner units being issued are outstanding, on the Class C units and the additional general partner units to reflect the fact that the Class C units and the additional general partner units will not be outstanding during the full quarterly period, and (iii) provide that certain amounts received by us under the omnibus agreement are to be treated as a capital contribution to us by Williams in the amount of such payment.

The Contributed Entities

Reimbursement of Expenses of Williams

Williams affiliates charge the Contributed Entities for the payroll and benefit costs associated with the employees that operate the Contributed Entities assets. The Contributed Entities share of those costs totaled $147 million for the year ended December 31, 2009.

In addition, general and administrative services are provided to the Contributed Entities by employees of Williams, and the Contributed Entities are charged for certain administrative expenses incurred by Williams. These charges are either directly identifiable or allocated to their operations. Direct charges are for goods and services provided by Williams at their request. Allocated charges are based on a three-factor formula, which considers revenues; property, plant and equipment; and payroll. The Contributed Entities share of direct administrative expenses was $181 million for the year ended December 31, 2009. The Contributed Entities share of allocated administrative expenses was $93 million for the year ended December 31, 2009. In management s estimation, the allocation methodologies used are reasonable and result in a reasonable allocation to the Contributed Entities of their costs of doing business incurred by Williams.

Commodity Sales Contracts

The Contributed Entities sell (a) feedstock commodities to Williams Olefins, LLC (Williams Olefins), a wholly owned subsidiary of Williams, for use in its facilities, (b) NGLs to our Conway fractionation and storage facility for its inventory balancing needs, and (c) waste heat from their co-generation plant to our Four Corners system for the natural gas treating process at its Milagro treating plant. Revenues from these product sales were $84 million for the year ended December 31, 2009. These sales are generally made at market prices at the time of sale. The rate the Contributed Entities charge for the waste heat is based on the volume and price of the natural gas needed to generate the waste heat. Following the Dropdown, we will consolidate the entities which sell NGLs and waste heat to Conway and Four Corners, respectively. As a result, the related purchases and sales amounts will be eliminated.

Gathering, Processing and Treating Contracts

The Contributed Entities provide gathering, treating and processing services for Williams Production Company (WPC), a wholly owned subsidiary of Williams, under several contracts. Revenues from these services were $29 million for the year ended December 31, 2009. The rates charged to provide these services are considered reasonable as compared to those that are charged to similarly-situated nonaffiliated customers.

Transportation and Exchange Contracts

The Contributed Entities provide natural gas transportation and exchange services and rental of communication facilities to subsidiaries of Williams. These revenues were $29 million for the year ended December 31, 2009. The rates charged to provide sales and services to affiliates are comparable to those that are charged to similarly-situated nonaffiliated customers.

Commodity Purchase Contracts

The Contributed Entities purchase for resale from WPC and Williams Olefins and certain of our subsidiaries substantially all of the NGLs to which those entities take title. The Contributed Entities conduct the purchases of the NGLs at market prices at the time of purchase. These purchases, excluding Wamsutter LLC, totaled $209 million for the year ended December 31, 2009. Following the Dropdown, we will consolidate the entity that purchases these products from us. As a result, our product sales will be eliminated against the related product cost recorded by this entity.

The Contributed Entities purchase natural gas for shrink replacement and fuel for processing plants and the co-generation plant from WGM at market prices at the time of purchase. They also purchase natural gas for Gas Pipeline s merchant gas sales program from WGM at contract or market prices. These purchases, excluding Wamsutter LLC, totaled $281 million for the year ended December 31, 2009.

In addition, through an agency agreement, WGM manages Transco s jurisdictional merchant gas sales. WGM is authorized to make gas sales on Transco s behalf in order to manage its gas purchase obligations. WGM receives all margins associated with jurisdictional merchant gas sales business and, as Transco s agent, assumes all market and credit risk associated with such sales. Consequently, Transco s merchant gas sales service has no impact on its operating income or results of operations. Transco s gas sales volumes managed by WGM for the year ended December 31, 2009 in TBtus was .4.

Other Contracts

In 2009, the Contributed Entities, excluding Wamsutter LLC, entered into forward month financial swap contracts with WGM, based on market rates at the time of execution, to hedge 33 million gallons of forecasted NGL sales for the second half of 2009 with a range of fixed prices of $.490 to $1.405 per gallon depending on the specific product and 58 million gallons of forecasted 2010 NGL sales with fixed prices of $.725 to $1.830 per gallon. In 2009, the Contributed Entities, excluding Wamsutter LLC, entered into fixed price natural gas purchase contracts for 2010 with WGM, based on market rates at the time of execution, to hedge the price of our natural gas shrink replacement costs for 41 BBtu/d at a range of fixed prices from $5.635 to $5.985 per MMBtu

The Contributed Entities transferred a transportation capacity contract to WGM in a previous year. To the extent WGM does not utilize this transportation capacity for its needs (primarily transporting third-party gas volumes), the Contributed Entities reimburse WGM for these transportation costs. These cost reimbursements totaled $9 million in 2009.

The Contributed Entities historically participated in Williams cash management program under unsecured promissory note agreements with Williams for both advances to and from Williams. Under the Contribution Agreement, the outstanding advances were distributed to Williams.

In June 2009, the Contributed Entities issued a $26 million note payable to Laurel Mountain, an equity method investee, in connection with its formation.

Review, Approval or Ratification of Transactions with Related Persons

Our partnership agreement contains specific provisions that address potential conflicts of interest between our general partner and its affiliates, including Williams, on one hand, and us and our subsidiaries, on the other hand. Whenever such a conflict of interest arises, our general partner will resolve the conflict. Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of the board of directors of our general partner, which is comprised of independent directors. The partnership agreement provides that our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or to our unitholders if the resolution of the conflict is:

- approved by the conflicts committee;

- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;

- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or fair and reasonable to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If our general partner does not seek approval from the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to reasonably believe that he is acting in the best interests of the partnership, unless the context otherwise requires. See Directors, Executive Officers and Corporate Governance Governance Board Committees Conflict Committee.

In addition, our code of business conduct and ethics requires that all employees, including employees of affiliates of Williams who perform services for us and our general partner, avoid or disclose any activity that may interfere, or have the appearance of interfering, with their responsibilities to us and our unitholders. Conflicts of interest that cannot be avoided must be disclosed to a supervisor who is then responsible for establishing and monitoring procedures to ensure that we are not disadvantaged.

Director Independence

Please read Directors, Executive Officers and Corporate Governance Governance Director Independence above for information about the independence of our general partner s board of directors and its committees, which information is incorporated herein by reference in its entirety.

Item 14. ***Principal Accounting Fees and Services***

Fees for professional services provided by our independent auditors for each of the last two fiscal years were as follows:

	2009	2008
	(Thousands)	
Audit Fees	$ 1,111	$ 1,066
Audit-Related Fees		
Tax Fees	35	35
All Other Fees		
	$ 1,146	$ 1,101

Fees for audit services in 2009 and 2008 include fees associated with the annual audit, the reviews of our quarterly reports on Form 10-Q, the audit of our assessment of internal controls as required by Section 404 of the Sarbanes-Oxley Act of 2002 and services provided in connection with other filings with the SEC. The fees for audit services do not include audit costs for stand-alone audits for equity investees, including Discovery or Wamsutter. Tax fees for 2009 and 2008 include fees for review of our federal tax return. Ernst & Young LLP does not provide tax services to our general partner s executive officers.

The audit committee of our general partner s board of directors is responsible for appointing, setting compensation for and overseeing the work of Ernst & Young LLP, our independent auditors. The audit committee has established a policy regarding pre-approval of all audit and non-audit services provided by Ernst & Young LLP. On an ongoing basis, our general partner s management presents specific projects and categories of service to the audit committee to request advance approval. The audit committee reviews those requests and advises management if the audit committee approves the engagement of Ernst & Young LLP. On a quarterly basis, the management of our general partner reports to the audit committee regarding the services rendered by, including the fees of, the independent accountant in the previous quarter and on a cumulative basis for the fiscal year. The audit committee may also delegate the ability to pre-approve audit and permitted non-audit services, excluding services related to our internal control over financial reporting, to any two committee members, provided that any such pre-approvals are reported at a subsequent audit committee meeting. In 2009 and 2008, 100% of Ernst & Young LLP s fees were pre-approved by the audit committee.

PART IV

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

(a) 1 and 2. *Williams Partners L.P. financials*

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

(a)3 and (b). The following documents are included as exhibits to this report:

Exhibit Number	Description
§Exhibit 2.1	Purchase and Sale Agreement, dated April 6, 2006, by and among Williams Energy Services, LLC, Williams Field Services Group, LLC, Williams Field Services Company, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on April 7, 2006 as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No.001-32599)) and incorporated herein by reference.
§Exhibit 2.2	Purchase and Sale Agreement, dated November 16, 2006, by and among Williams Energy Services, LLC, Williams Field Services Group, LLC, Williams Field Services Company, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on November 21, 2006 as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No.001-32599)) and incorporated herein by reference.
§Exhibit 2.3	Purchase and Sale Agreement, dated June 20, 2007, by and among Williams Energy, L.L.C., Williams Energy Services, LLC and Williams Partners Operating LLC (filed on June 25, 2007 as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
§Exhibit 2.4	Purchase and Sale Agreement, dated November 30, 2007, by and among Williams Energy Services, LLC, Williams Field Services Group, LLC, Williams Field Services Company, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on December 3, 2007 as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 2.5	Contribution Agreement, dated as of January 15, 2010, by and among Williams Energy Services, LLC, Williams Gas Pipeline Company, LLC, WGP Gulfstream Pipeline Company, L.L.C., Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and, for a limited purpose, The Williams Companies, Inc, including exhibits thereto (filed on January 19, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 3.1	Certificate of Limited Partnership of Williams Partners L.P. (filed on May 2, 2005 as Exhibit 3.1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.2	Certificate of Formation of Williams Partners GP LLC (filed on May 2, 2005 as Exhibit 3.3 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
*Exhibit 3.3	Amended and Restated Agreement of Limited Partnership of Williams Partners L.P. (including form of common unit certificate), as amended by Amendments Nos. 1, 2, 3, 4, 5, and 6.
Exhibit 3.4	

	Amended and Restated Limited Liability Company Agreement of Williams Partners GP LLC (filed on August 26, 2005 as Exhibit 3.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.1	Indenture, dated June 20, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and JPMorgan Chase Bank, N.A. (filed on June 20, 2006 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.2	Form of 7 $^{1}/2$% Senior Note due 2011 (filed on June 20, 2006 as Exhibit 1 to Rule 144A/Regulation S Appendix of Exhibit 4.1 attached to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.3	Certificate of Incorporation of Williams Partners Finance Corporation (filed on September 22, 2006 as Exhibit 4.5 to Williams Partners L.P. s registration statement on Form S-3 (File No. 333-137562)) and incorporated herein by reference.
Exhibit 4.4	Bylaws of Williams Partners Finance Corporation (filed on September 22, 2006 as Exhibit 4.6 to

Exhibit Number	Description
	Williams Partners L.P. s registration statement on Form S-3 (File No. 333-137562)) and incorporated herein by reference.
Exhibit 4.5	Indenture, dated December 13, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and The Bank of New York (filed on December 19, 2006 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.6	Form of 7 1/4% Senior Note due 2017 (filed on December 19, 2006 as Exhibit 1 to Rule 144A/Regulation S Appendix of Exhibit 4.1 attached to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.7	Indenture, dated as of February 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 10, 2010 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.8	Registration Rights Agreement, dated as of February 9, 2010, among Williams Partners L.P. and Barclays Capital Inc. and Citigroup Global Markets Inc., each acting on behalf of themselves and the initial purchasers listed on Schedule I thereto (filed on February 10, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.9	Limited Call Right Forbearance Agreement, dated as of February 17, 2010, by and between Williams Partners L.P. and Williams Partners GP LLC (filed on February 22, 2010 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.10	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee with regard to Northwest Pipeline s 7.125% Debentures, due 2025 (filed September 14, 1995 as Exhibit 4.1 to Northwest Pipeline Corporation s Form S-3 (File No. 033-62639)) and incorporated herein by reference.
Exhibit 4.11	Indenture, dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee, with regard to Northwest Pipeline s $175 million aggregate principal amount of 7.00% Senior Notes due 2016 (filed on June 23, 2006 as Exhibit 4.1 to Northwest Pipeline Corporation s Form 8-K (File. No. 001-07414) and incorporated herein by reference.
Exhibit 4.12	Indenture, dated as of April 5, 2007, between Northwest Pipeline Corporation and The Bank of New York (filed on April 5, 2007 as Exhibit 4.1 to Northwest Pipeline Corporation s Form 8-K (File No. 001-07414)) and incorporated herein by reference.
Exhibit 4.13	Indenture, dated May 22, 2008, between Northwest Pipeline GP and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Northwest Pipeline GP s Form 8-K File No. 001-07414)) and incorporated herein by reference.
Exhibit 4.14	

	Registration Rights Agreement, dated as of May 23, 2008, among Northwest Pipeline GP and Banc of America Securities, LLC, BNP Paribas Securities Corp, and Greenwich Capital Markets, Inc., acting on behalf of themselves and the several initial purchasers listed on Schedule I thereto (filed on May 23, 2008 as Exhibit 10.1 to Northwest Pipeline GP s Form 8-K (File No. 001-07414)) and incorporated herein by reference.
Exhibit 4.15	Senior Indenture, dated as of July 15, 1996 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on April 2, 1996 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-3 (File No. 333-02155)) and incorporated herein by reference.
Exhibit 4.16	Senior Indenture, dated as of January 16, 1998, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on September 8, 1997 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-3 (File No. 333-27311)) and incorporated herein by reference.
Exhibit 4.17	Indenture, dated as of August 27, 2001, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on November 8, 2001 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-4 (File No. 333-72982)) and incorporated herein by reference.
Exhibit 4.18	Indenture, dated as of July 3, 2002, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed August 14, 2002 as Exhibit 4.1 to The Williams Companies Inc. s Form 10-Q (File No. 001-07584)) and incorporated herein by reference.
Exhibit 4.19	Indenture, dated December 17, 2004, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee (filed on December 21, 2004 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 4.20	Indenture, dated as of April 11, 2006, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee with regard to Transcontinental Gas Pipe Line s $200 million

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Exhibit Number	Description
	aggregate principal amount of 6.4% Senior Note due 2016 (filed on April 11, 2006 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 4.21	Indenture, dated May 22, 2008, between Transcontinental Gas Pipe Line Corporation and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 4.22	Registration Rights Agreement, dated as of May 22, 2008, among Transcontinental Gas Pipe Line Corporation and Banc of America Securities LLC, Greenwich Capital Markets, Inc., and J. P. Morgan Securities Inc., acting on behalf of themselves and the several initial purchasers listed on Schedule I thereto (filed on May 23, 2008 as Exhibit 10.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 10.1	Credit Agreement, dated as of December 11, 2007, by and among Williams Partners L.P., the lenders party hereto, Citibank, N.A., as Administrative Agent and Issuing Bank, and The Bank of Nova Scotia, as Swingline Lender (filed on December 17, 2007 as Exhibit 10.5 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.2	Omnibus Agreement, among Williams Partners L.P., Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Partners Holdings LLC, Williams Discovery Pipeline LLC, Williams Partners GP LLC, Williams Partners Operating LLC and (for purposes of Articles V and VI thereof only) The Williams Companies, Inc. (filed on August 26, 2005 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.3	Amendment No. 1 to Omnibus Agreement among Williams Partners L.P., Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Partners Holdings LLC, Williams Discovery Pipeline LLC, Williams Partners GP LLC, Williams Partners Operating LLC and (for purposes of Articles V and VI thereof only) The Williams Companies, Inc. (filed on April 20, 2009 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.4	Omnibus Agreement, dated as of February 17, 2010, by and between The Williams Companies, Inc. and Williams Partners L.P. (filed on February 22, 2010 as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.5	Contribution, Conveyance and Assumption Agreement, dated August 23, 2005, by and among Williams Partners L.P., Williams Energy, L.L.C., Williams Partners GP LLC, Williams Partners Operating LLC, Williams Energy Services, LLC, Williams Discovery Pipeline LLC, Williams Partners Holdings LLC and Williams Natural Gas Liquids, Inc. (filed on August 26, 2005 as Exhibit 10.3 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.6	Contribution, Conveyance and Assumption Agreement, dated June 20, 2006, by and among Williams Energy Services, LLC, Williams Field Services Company, LLC, Williams Field Services

Group, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on June 20, 2006 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.

Exhibit 10.7	Contribution, Conveyance and Assumption Agreement, dated June 20, 2006, by and among Williams Field Services Company, LLC and Williams Four Corners LLC (filed on June 20, 2006 as Exhibit 10.4 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference.
Exhibit 10.8	Contribution, Conveyance and Assumption Agreement, dated December 13, 2006, by and among Williams Energy Services, LLC, Williams Field Services Company, LLC, Williams Field Services Group, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on December 19, 2006 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.9	Contribution, Conveyance and Assumption Agreement, dated December 11, 2007, by and among Williams Energy Services, LLC, Williams Field Services Company, LLC, Williams Field Services Group, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on December 17, 2007 as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.10	Conveyance, Contribution and Assumption Agreement, dated as of February 17, 2010, by and among Williams Energy Services, LLC, Williams Gas Pipeline Company, LLC, WGP Gulfstream Pipeline Company, L.L.C., Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating

Exhibit Number	Description
	LLC (filed on February 22, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.11	Assignment Agreement, dated December 11, 2007, by and between Williams Field Services Company, LLC and Wamsutter LLC (filed on December 17, 2007 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.12	Third Amended and Restated Limited Liability Company Agreement for Discovery Producer Services LLC (filed on June 24, 2005 as Exhibit 10.7 to Amendment No. 1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 10.13	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement for Discovery Producer Services LLC (filed on August 8, 2006 as Exhibit 10.6 to Williams Partners L.P. s quarterly report on Form 10-Q (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.14	Amendment No. 2 to Third Amended and Restated Limited Liability Company Agreement for Discovery Producer Services LLC (filed on August 6, 2009 as Exhibit 10.3 to Williams Partners L.P. s quarterly report on Form 10-Q (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.15	Amended and Restated Limited Liability Company Agreement of Wamsutter LLC, dated December 1, 2007, by and between Williams Field Services Company, LLC and Williams Partners Operating LLC (filed on December 17, 2007 as Exhibit 10.3 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.16	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Wamsutter LLC, dated as of February 17, 2010, by and between Williams Field Services Company, LLC and Williams Partners Operating LLC (filed on February 22, 2010 as Exhibit 10.4 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
#Exhibit 10.17	Williams Partners GP LLC Long-Term Incentive Plan (filed on August 26, 2005 as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
#Exhibit 10.18	Amendment to the Williams Partners GP LLC Long-Term Incentive Plan, dated November 28, 2006 (filed on December 4, 2006 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
#Exhibit 10.19	Amendment No. 2 to the Williams Partners GP LLC Long-Term Incentive Plan, dated December 2, 2008 (filed on February 26, 2009, as Exhibit 10.4 to Williams Partners L.P. s annual report on Form 10-K (File No. 001-32599)) and incorporated herein by reference.
#Exhibit 10.20	Director Compensation Policy dated November 29, 2005, as revised May 28, 2009 (filed on August 6, 2009 as Exhibit 10.2 to Williams Partners L.P. s quarterly report on Form 10-Q (File No. 001-32599)) and incorporated herein by reference.

#Exhibit 10.21	Form of Grant Agreement for Restricted Units (filed on December 1, 2005 as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.22	Administrative Services Agreement between Northwest Pipeline Services LLC and Northwest Pipeline GP, dated October 1, 2007 (filed on January 30, 2008 as Exhibit 10.1 to Williams Pipeline Partners L.P. s Form 8-K (File No. 001-33917) and incorporated herein by reference).
Exhibit 10.23	Administrative Services Agreement, dated as of February 17, 2010, by and between Transco Pipeline Services LLC and Transcontinental Gas Pipe Line Company, LLC (filed on February 22, 2010 as Exhibit 10.3 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.24	Credit Agreement, dated as of February 17, 2010, by and among Williams Partners L.P., Transcontinental Gas Pipe Line Company, LLC, Northwest Pipeline GP, the lenders party thereto and Citibank, N.A., as Administrative Agent (filed on February 22, 2010 as Exhibit 10.5 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
*Exhibit 12	Computation of Ratio of Earnings to Fixed Charges
*Exhibit 21	List of subsidiaries of Williams Partners L.P.
*Exhibit 23.1	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
*Exhibit 23.2	Consent of Independent Auditors, Ernst & Young LLP.
*Exhibit 24	Power of attorney.

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Exhibit Number	Description
*Exhibit 31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
*Exhibit 31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
*Exhibit 32	Section 1350 Certifications of Chief Executive Officer and Chief Financial Officer.

* Filed herewith.

§ Pursuant to item 601(b) (2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

Management contract or compensatory plan or arrangement.

(c) *Wamsutter LLC financial statements and notes thereto Discovery Producer Services LLC financial statements and notes thereto*

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Report of Independent Auditors

To the Management Committee of
Wamsutter LLC

We have audited the accompanying balance sheets of Wamsutter LLC as of December 31, 2009 and 2008, and the related statements of income, members capital, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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. We were not engaged to perform an audit of Wamsutter LLC s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Wamsutter LLC 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, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Wamsutter LLC at December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009 in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 25, 2010

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WAMSUTTER LLC
BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands)	
ASSETS		
Current assets:		
Accounts receivable:		
Trade	$ 6,116	$ 8,755
Affiliate	10,895	7,178
Other	252	100
Product imbalance	4,199	1,032
Other current assets	229	82
Total current assets	21,691	17,147
Property, plant and equipment, net	408,429	318,072
Other noncurrent assets	3,071	468
Total assets	$ 433,191	$ 335,687
LIABILITIES AND MEMBERS CAPITAL		
Current liabilities:		
Accounts payable:		
Trade	$ 15,215	$ 9,582
Affiliate	2,734	2,407
Product imbalance	986	1,753
Accrued liabilities	10,285	3,218
Total current liabilities	29,220	16,960
Other noncurrent liabilities	4,846	4,353
Commitments and contingencies (Note 10)		
Members capital	399,125	314,374
Total liabilities and members capital	$ 433,191	$ 335,687

See accompanying notes to financial statements.

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WAMSUTTER LLC
STATEMENTS OF INCOME

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Revenues:			
Product sales:			
Affiliate	$ 95,734	$ 134,776	$ 93,744
Third-party	15,348	27,384	7,447
Gathering and processing services	79,523	68,670	67,904
Other revenues	5,282	8,704	6,214
Total revenues	195,887	239,534	175,309
Costs and expenses:			
Product cost:			
Affiliate	33,928	63,064	34,973
Third-party	18,372	15,745	11,066
Operating and maintenance expense:			
Affiliate	2,749	(1,513)	36
Third-party	17,778	22,486	18,221
Depreciation and accretion	22,235	21,182	18,424
General and administrative expense:			
Affiliate	14,801	12,837	11,825
Third-party	406	670	798
Taxes other than income	2,014	1,868	1,637
Other (income) expense net	(448)	(569)	944
Total costs and expenses	111,835	135,770	97,924
Net income	$ 84,052	$ 103,764	$ 77,385

See accompanying notes to financial statements.

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WAMSUTTER LLC
STATEMENT OF MEMBERS CAPITAL

	Predecessor Owner s Equity	Williams Partners Class A	Williams Class B	Class C* Williams	Class C* Williams Partners	Total
			(In thousands)			
Balance December 31, 2006	$ 263,245	$	$	$	$	$ 263,245
Net income through November 30, 2007	70,023					70,023
Distributions	(55,006)					(55,006)
	278,262					278,262
Conversion of predecessor owner s equity to member capital	(278,262)	276,262		1,000	1,000	
Net income December 2007		7,362				7,362
Capital contributions			1,088			1,088
Balance December 31, 2007		283,624	1,088	1,000	1,000	286,712
Net income 2008		73,312		15,226	15,226	103,764
Capital contributions		3,658	31,240			34,898
Transition support contribution (distribution)		(7,614)	7,614			
Distributions		(72,050)		(19,475)	(19,475)	(111,000)
Balance December 31, 2008		280,930	39,942	(3,249)	(3,249)	314,374
Net income 2009		84,052				84,052
Capital contributions		1,011	84,688			85,699
Transition support contribution (distribution)		(9,718)	9,718			
Distributions		(70,750)		(4,496)	(9,754)	(85,000)
Class C units issued		(4,621)	(1,439)	1,439	4,621	
Balance December 31, 2009	$	$ 280,904	$ 132,909	$ (6,306)	$ (8,382)	$ 399,125

* Williams Partners and Williams held 108.45 and 48.79 Class C units, respectively, as of December 31, 2009.

See accompanying notes to financial statements.

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WAMSUTTER LLC
STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
OPERATING ACTIVITIES:			
Net income	$ 84,052	$ 103,764	$ 77,385
Adjustments to reconcile to cash provided by operations:			
Depreciation and accretion	22,235	21,182	18,424
Provision for loss on property plant & equipment			1,392
Cash provided (used) by changes in current assets and liabilities:			
Accounts receivable	(1,230)	7,334	(16,655)
Other current assets	(147)	1,627	(29)
Accounts payable	5,699	(753)	6,113
Product imbalance	(3,934)	463	(1,335)
Accrued liabilities	322	115	(662)
Deferred revenue	400	335	882
Other, including changes in other noncurrent assets and liabilities	(2,560)	(426)	26
Net cash provided by operating activities	104,837	133,641	85,541
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(105,536)	(57,539)	(31,624)
Net cash used by investing activities	(105,536)	(57,539)	(31,624)
FINANCING ACTIVITIES:			
Distributions	(85,000)	(111,000)	(55,005)
Capital contributions	85,699	34,898	1,088
Transition support payments received from Class B member	9,718	7,614	
Transition support payments distributed to Class A member	(9,718)	(7,614)	
Net cash provided (used) by financing activities	699	(76,102)	(53,917)
Increase in cash and cash equivalents			
Cash and cash equivalents at beginning of year			
Cash and cash equivalents at end of year	$	$	$

See accompanying notes to financial statements.

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WAMSUTTER LLC
NOTES TO FINANCIAL STATEMENTS

Note 1. Basis of Presentation

References in this report to we, our, us or like terms refer to Wamsutter LLC. In June 2007, Williams Field Services Company, LLC (WFSC) formed Wamsutter LLC, and on December 11, 2007, WFSC conveyed a natural gas gathering and processing system in Wyoming previously held by WFSC (the Wamsutter assets) into Wamsutter LLC in connection with the acquisition of certain ownership interests in Wamsutter LLC by Williams Partners L.P. (the Partnership). WFSC is a wholly owned subsidiary of The Williams Companies, Inc (Williams). The Partnership owned 100% of our Class A membership interests and 50% of our initial Class C units (or 20 Class C units). WFSC owned 100% of our Class B membership interests and the remaining 50% of our initial Class C units (or 20 Class C units). In 2009 we issued an additional 88.5 and 28.8 Class C units to the Partnership and WFSC, respectively, related to their funding of expansion capital expenditures. Therefore, the Partnership owns 69% and WFSC owns 31% of our outstanding Class C units as of December 31, 2009. See Note 8, Members Capital, for more information about these different forms of ownership and Note 11, Subsequent Event, for a discussion of a subsequent change of ownership.

Note 2. Description of Business

We operate a natural gas gathering and processing system in Wyoming. The system includes approximately 1,900 miles of natural gas gathering pipelines with typical operating capacity of approximately 500 million cubic feet per day (MMcf/d) at current operating pressures. The system has total compression of approximately 69,000 horsepower. The assets also include the Echo Springs natural gas processing plant, which has an inlet capacity of 500 MMcf/d and can produce approximately 30,000 barrels per day of natural gas liquids.

Note 3. Summary of Significant Accounting Policies

Basis of Presentation. The financial statements have been prepared based upon accounting principles generally accepted in the United States.

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 financial statements and accompanying notes. Actual results could differ from those estimates.

Estimates and assumptions which, in the opinion of management, are significant to the underlying amounts included in the financial statements and for which it would be reasonably possible that future events or information could change those estimates include asset retirement obligations. These estimates are discussed further in the accompanying notes.

Accounts Receivable. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. We do not recognize an allowance for doubtful accounts at the time the revenue which generates the accounts receivable is recognized. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of our customers and the amount and age of past due accounts. We consider receivables past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been unsuccessful. There was no allowance for doubtful accounts as of December 31, 2009 and 2008.

Product Imbalances. In the course of providing gathering and processing services to our customers, we realize over and under deliveries of our customers products, and over and under purchases of shrink replacement gas when our purchases vary from operational requirements. In addition, we realize gains and losses which we believe are related to inaccuracies inherent in the gas measurement process. These items are reflected as product imbalance receivables and payables on the Balance Sheets. Product imbalance receivables are valued based on the lower of the current market prices or current cost of natural gas in the system. Product imbalance payables are valued at current market prices. The majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are ongoing and take place over several periods. In some cases, settlements of imbalances built up over a period of time are ultimately settled in cash and are generally negotiated at values which approximate average market prices over a period of time. These gains and losses impact our results of operations and are included in operating and maintenance expense in the Statements of Income.

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. Depreciation of property, plant and equipment is provided on a straight-line basis over estimated useful lives. Expenditures for maintenance and repairs are expensed as incurred. Expenditures that extend the useful lives of the assets or increase their functionality are capitalized. We remove the cost of property, plant and equipment sold or retired and the related accumulated depreciation from the accounts in the period of sale or disposition. Gains and losses on the disposal of property, plant and equipment are recorded in the Statements of Income.

We record an asset and a liability equal to the present value of each expected future asset retirement obligation (ARO). The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as corresponding accretion expense included in operating income.

Revenue Recognition. We recognize revenue for sales of products when the product has been delivered, and we generally recognize revenues from the gathering and processing of gas in the period the service is provided based on contractual terms and the related natural gas and liquid volumes. One gathering agreement provides incremental fee-based revenues upon the completion of projects that lower system pressures. This revenue is recognized on a units-of-production basis as gas is produced under this agreement. Additionally, revenue from customers for the installation and operation of electronic flow measurement equipment is recognized evenly over the life of the underlying agreements.

Income Taxes. We are not a taxable entity for federal and state income tax purposes. The tax on our net income is borne by the individual members through the allocation of taxable income. Net income for financial statement purposes may differ significantly from taxable income of members as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

Note 4. Related Party Transactions

The employees supporting our operations are employees of Williams. Their payroll costs are directly charged to us by Williams. Williams carries the accruals for most employee-related liabilities in its financial statements, including the liabilities related to the employee retirement and medical plans and paid time off. Our share of these costs is charged to us through affiliate billing and reflected in Operating and maintenance expense Affiliate in the accompanying Statements of Income.

We purchase natural gas for fuel and shrink replacement from Williams Gas Marketing, Inc., a wholly owned indirect subsidiary of Williams. These purchases are made at market rates at the time of purchase. In 2009, we entered into fixed price natural gas purchase contracts with WGM, based on market rates at the time of execution, to hedge a range of 5 BBtu/d to 10 BBtu/d forecasted natural gas purchases for shrink replacement costs at a range of fixed prices from $2.91 to $3.48 per MMBtu for the last half of 2009. These costs are reflected in Operating and maintenance expense Affiliate and Product cost Affiliate in the accompanying Statements of Income.

A summary of affiliate operating and maintenance expense directly charged to us for the periods stated is as follows:

	2009	2008	2007
		(In thousands)	
Operating and maintenance expense Affiliate:			
Natural gas fuel purchases and system (gains) losses	$ (3,392)	$ (7,287)	$ (5,225)
Salaries, benefits and other	6,141	5,774	5,261
	$ 2,749	$ (1,513)	$ 36

We are charged for certain administrative expenses by Williams and its Midstream segment of which we are a part. These charges are either directly identifiable or allocated to our assets. Direct charges are for goods and services provided by Williams and Midstream at our request. Allocated charges are either (1) charges allocated to the

Midstream segment by Williams and then reallocated from the Midstream segment to us or (2) Midstream-level administrative costs that are allocated to us. These expenses are allocated based on a three-factor formula, which considers revenues, property, plant and equipment and payroll. These costs are reflected in General and administrative expenses Affiliate in the accompanying Statements of Income. In management s estimation, the allocation methodologies used are reasonable and result in a reasonable allocation to us of our costs of doing business incurred by Williams and its Midstream segment.

We sell the NGLs to which we take title to Williams NGL Marketing, LLC (WNGLM), a wholly owned indirect subsidiary of Williams. These sales are made at market rates at the time of sale. In 2009, we entered into financial swap contracts with WGM, based on market rates at the time of execution, to hedge 21 million gallons of forecasted NGL sales for the second half of 2009 with a range of fixed prices of $0.465 per gallon to $0.923 per gallon depending on the specific product. Revenues associated with these activities are reflected as Product sales Affiliate on the Statements of Income.

We participate in Williams cash management program under unsecured promissory note agreements with Williams for both advances to and from Williams; hence, we maintain no cash balances. As of December 31, 2009 and 2008 we had receivables from Williams of $2.4 million and $4.8 million, respectively. Interest is paid to us on amounts receivable from Williams under the cash management program based on the rate received by Williams on the overnight investment of its excess cash.

Note 5. Property, Plant and Equipment

Property, plant and equipment, at cost, is as follows:

	December 31, 2009	December 31, 2008	Estimated Depreciable Lives
	(In thousands)		
Land, rights of way and other	$ 24,406	$ 22,365	0- 30 years
Gathering pipelines and related equipment	349,681	336,041	10-30 years
Processing plants and related equipment	55,275	50,771	30 years
Buildings and related equipment	11,594	11,476	3-30 years
Construction work in progress	134,571	42,326	
Total property, plant and equipment	575,527	462,979	
Accumulated depreciation	167,098	144,907	
Net property, plant and equipment	$ 408,429	$ 318,072	

Our asset retirement obligation relates to gas processing and compression facilities located on leased land and wellhead connections on federal land. At the end of the useful life of each respective asset, we are legally or contractually obligated to remove certain surface equipment and cap certain gathering pipelines at the wellhead connection.

A rollforward of our asset retirement obligation for 2009 and 2008 is presented below.

	2009	2008
	(In thousands)	
Balance, January 1	$ 1,656	$ 221
Liabilities incurred during the period	86	
Accretion expense	38	15
Estimate revisions	112	1,420
Balance, December 31	$ 1,892	$ 1,656

Note 6. Accrued Liabilities

Accrued liabilities are as follows:

	December 31, 2009	December 31, 2008

	(In thousands)	
Taxes other than income	$ 1,009	$ 933
Construction retainage	8,766	2,206
Other	510	79
	$ 10,285	$ 3,218

Note 7. Credit Facilities and Leasing Activities

We have a $20.0 million revolving credit facility with Williams as the lender. The credit facility is available exclusively to fund working capital requirements. Borrowings under the credit facility mature on December 12, 2010 with three, one-year automatic extensions which can be terminated by either party. We pay a commitment fee to Williams on the unused portion of the credit facility of 0.125% annually. Interest on any borrowings under the facility will be based upon a periodic fixed rate equal to LIBOR plus an applicable margin, or a base rate plus the applicable margin. As of December 31, 2009, we had no outstanding borrowings under the credit facility. See Note 11, Subsequent Event , for information regarding the termination of this credit facility.

We lease the land on which a significant portion of our pipeline assets are located. The primary landowner is the Bureau of Land Management (BLM). The BLM leases are for thirty years with renewal options. We also lease compression units under a lease agreement which terminates November 18, 2010. In addition, we lease vehicles under non-cancelable leases, which are for lease terms of about 45 months. These leases are accounted for as operating leases. The future minimum annual rentals under these non-cancelable leases as of December 31, 2009 are payable as follows:

	(In thousands)
2010	$ 1,221
2011	150
2012	60
2013 and thereafter	8
	$ 1,439

Total rent expense for the years ended 2009, 2008 and 2007 was $2.0 million, $2.1 million and $2.0 million, respectively.

Note 8. Members Capital

Governance. Most decisions regarding our day-to-day operations are made by Williams in its capacity as the Class B member. However, certain decisions require the consent of the Class A member, including, but not limited to, (i) the sale or disposition of assets over $20.0 million, (ii) the merger or consolidation with another entity, (iii) the purchase or acquisition of assets or businesses, (iv) the making of an investment in a third party in excess of $20.0 million, (v) the guarantee or incurrence of any debt, (vi) the cancelling or settling of any claim in excess of $20.0 million, (vii) the selling or redeeming of any equity interests in us, (viii) the declaration of distributions not described below, (ix) the entering into certain transactions outside the ordinary course of business with our affiliates and (x) the approval of our annual business plan. Williams also controls the Class A member through its ownership of the Class A member s general partner.

Distributions. Our limited liability company (LLC) agreement provides for distributions of available cash to be made quarterly. We distribute our available cash as follows:

First, an amount equal to $17.5 million per quarter to the holder of our Class A membership interests;

Second, an amount, if needed, to the holder of our Class A membership interests to increase the distribution on our Class A membership interests in prior quarters of the current distribution year to $17.5 million per quarter; and

Third, 5% of remaining available cash shall be distributed to the holder of our Class A membership interests and 95% shall be distributed to the holders of our Class C units, on a *pro rata* basis.

In addition, to the extent that at the end of the fourth quarter of a distribution year, our Class A member has received less than $70.0 million under the first and second bullets above, our Class C members will be required to repay any distributions they received in that distribution year such that our Class A member receives $70.0 million for that distribution year. If this repayment is insufficient to result in the Class A member receiving $70.0 million, the shortfall will not carry forward to the next distribution year. Our initial distribution year began on December 1, 2007 and ended on November 30, 2008. Subsequent distribution years commence on December 1 and end on November 30.

Our LLC agreement provides that we will receive a transition support payment, related to a cap on general and administrative expenses, from our Class B membership interest each quarter during 2008 through 2012. This payment is distributed directly to our Class A membership interest who receives allocated income equal to the distribution. The reimbursement is treated as a capital contribution by our Class B membership interest.

Income Allocation. The allocation of our net income is based upon the allocation and distribution provisions of our LLC agreement. In general, the agreement allocates income to the Class A, B and C membership interests in a manner that will maintain capital account balances reflective of the amounts each membership interest would receive if we were dissolved and liquidated at our carrying value. The Class A membership interest will receive 100% of our annual net income up to $70.0 million. Income in excess of $70 million will be shared between the Class A membership interest and Class C membership interest. Our net income allocation does not affect the amount of available cash we distribute for any quarter.

Contributions for Capital Expenditures. We fund expansion capital expenditures through capital contributions from our members as specified in our LLC agreement. The agreement specifies that expansion capital expenditures with expected total expenditures in excess of $2.5 million at the time of approval and well connections that grow gathered volumes as defined in our LLC agreement be funded by contributions from our Class B member. Our Class A member will provide capital contributions related to expansion projects with expected total expenditures less than $2.5 million at the time of approval. On the first day of the quarter following the quarter the asset related to these expansion capital expenditures is placed in service, we will issue to each contributing member one Class C unit for each $50,000 contributed by it, including the interest accrued on the investment prior to the issuance of the Class C units. We will issue fractional Class C units as necessary. As of December 31, 2009 Williams has contributed an additional $82.9 million for an expansion capital project that is expected to be placed in service during 2010. Williams will receive Class C units related to these expenditures after the asset is placed in service.

Limitations of members liability. Our LLC agreement provides that we will indemnify and hold harmless each member from and against all losses, claims, damages, liabilities, expenses (including attorneys fees), and other amounts, that arise out of or are incidental to our business or the member s status as a member, unless incurred due to the actual fraud or willful misconduct of the member. The LLC agreement further provides that no member will be personally liable for any of our debts, liabilities or obligations with the exception of certain capital contributions provided by the terms of our LLC agreement and the amount of any distribution made to such member that must be returned to us pursuant to the Delaware Limited Liability Company Act.

Liquidation preferences. Our LLC agreement provides that proceeds from liquidation would be distributed in preferential order to the Class B, A and C members with each of these members fully recovering its unrecovered capital account balance before moving to the next class of ownership. Any remaining proceeds would be distributed 5% to the Class A membership interest and 95% to the Class C membership interest.

Note 9. Major Customers and Concentrations of Credit Risk

At December 31, 2009 and 2008, substantially all of our accounts receivable result from product sales and gathering and processing services provided to our five largest customers. One customer is an affiliate of Williams which minimizes our credit risk exposure. The remaining customers may impact our overall credit risk either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic or other conditions. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly. Our credit policy and the relatively short duration of receivables mitigate the risk of uncollected receivables.

Our largest customer, on a percentage of revenues basis, is WNGLM, which purchases and resells substantially all of the NGLs to which we take title. WNGLM accounted for 51%, 56% and 56% of revenues in 2009, 2008 and 2007, respectively. The percentages for the remaining three largest customers are as follows:

	2009	2008	2007
Customer A	21%	15%	20%
Customer B	8	7	10
Customer C	7	10	4

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Note 10. Commitments and Contingencies

Will Price. In 2001, we were named, along with other subsidiaries of Williams, as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs and sought an unspecified amount of damages. The defendants have opposed class certification, and on September 18, 2009, the court denied plaintiffs most recent motion to certify the class. On October 2, 2009, the plaintiffs filed a motion for reconsideration of the denial. We are awaiting a decision from the court. The amount of any possible liability cannot be reasonably estimated at this time.

Other. We are not currently a party to any other legal proceedings but are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business.

Summary. Litigation, arbitration, regulatory matters and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a material adverse effect upon our future liquidity or financial position.

Note 11. Subsequent Event

On February 17, 2010, the Partnership, its general partner, its operating company and certain subsidiaries of Williams closed a transaction pursuant to which the Partnership acquired certain subsidiaries of Williams, including WFSC. As a result, we became wholly owned by the Partnership. In connection with this transaction, our revolving credit facility with Williams was terminated.

We have evaluated our disclosure of subsequent events through February 25, 2010.

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Report of Independent Registered Public Accounting Firm

To the Management Committee of
Discovery Producer Services LLC

We have audited the accompanying consolidated balance sheets of Discovery Producer Services LLC as of December 31, 2009 and 2008, and the related consolidated statements of income, members capital, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Discovery Producer Services LLC at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 25, 2010

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DISCOVERY PRODUCER SERVICES LLC
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,074	$ 42,052
Trade accounts receivable:		
Affiliate	12,399	202
Other	8,665	1,899
Insurance receivable	4,647	3,373
Prepaid insurance	2,484	2,700
Other current assets	1,185	752
Total current assets	39,454	50,978
Restricted cash		3,470
Property, plant, and equipment, net	364,932	370,482
Total assets	$ 404,386	$ 424,930
LIABILITIES AND MEMBERS CAPITAL		
Current liabilities:		
Accounts payable:		
Affiliate	$ 1,986	$ 3,125
Other	12,329	34,779
Accrued liabilities	1,101	5,714
Other current liabilities	1,292	1,616
Total current liabilities	16,708	45,234
Asset retirement obligations	23,325	19,684
Other noncurrent liabilities	30	87
Members capital	364,323	359,925
Total liabilities and members capital	$ 404,386	$ 424,930

See accompanying notes to consolidated financial statements.

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DISCOVERY PRODUCER SERVICES LLC
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Revenues:			
Product sales:			
Affiliate	$ 114,738	$ 207,706	$ 216,889
Third-party	66	1,324	5,251
Gas and condensate transportation services:			
Affiliate	485	782	979
Third-party	20,155	13,308	15,553
Gathering and processing services:			
Affiliate	131	1,506	3,092
Third-party	17,831	12,709	17,767
Other revenues	7,613	3,913	1,141
Total revenues	161,019	241,248	260,672
Costs and expenses:			
Product cost and shrink replacement:			
Affiliate	20,235	83,576	93,722
Third-party	52,271	63,422	61,982
Operating and maintenance expenses:			
Affiliate	9,580	8,836	5,579
Third-party	13,865	27,834	23,409
Depreciation and accretion	18,751	21,324	25,952
Taxes other than income	3,263	1,439	1,330
General and administrative expenses affiliate	6,000	4,500	2,280
Other (income) expense, net	10	(3,511)	534
Total costs and expenses	123,975	207,420	214,788
Operating income	37,044	33,828	45,884
Interest income	31	650	1,799
Foreign exchange gain (loss)	(168)	(78)	388
Net income	$ 36,907	$ 34,400	$ 48,071

See accompanying notes to consolidated financial statements.

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DISCOVERY PRODUCER SERVICES LLC
CONSOLIDATED STATEMENT OF MEMBERS CAPITAL

	Williams Energy, L.L.C.	Williams Partners Operating LLC	DCP Assets Holding, LP	Total
Balance at December 31, 2006	$ 83,825	$ 167,765	$ 162,040	$ 413,630
Contributions			3,920	3,920
Distributions	(7,233)	(28,270)	(23,669)	(59,172)
Net income	2,602	26,241	19,228	48,071
Sale of Williams Energy, L.L.C. s 20% interest to Williams Partners Operating LLC	(79,194)	79,194		
Balance at December 31, 2007		244,930	161,519	406,449
Contributions		5,700	7,376	13,076
Distributions		(56,400)	(37,600)	(94,000)
Net income		20,641	13,759	34,400
Balance at December 31, 2008		214,871	145,054	359,925
Contributions		13,166	6,967	20,133
Distributions		(30,747)	(20,498)	(51,245)
Special Distribution of Interest Earned on Tahiti Escrow Account to Williams Partners Operating LLC		(1,397)		(1,397)
Net income		22,703	14,204	36,907
Balance at December 31, 2009	$	$ 218,596	$ 145,727	$ 364,323

See accompanying notes to consolidated financial statements.

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DISCOVERY PRODUCER SERVICES LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
OPERATING ACTIVITIES:			
Net income	$ 36,907	$ 34,400	$ 48,071
Adjustments to reconcile to cash provided by operations:			
Depreciation and accretion	18,751	21,324	25,952
Net loss on disposal of equipment		175	603
Cash provided (used) by changes in assets and liabilities:			
Trade accounts receivable	(18,963)	26,213	(9,389)
Insurance receivable	(1,274)	2,319	6,931
Prepaid insurance	216	(267)	1,004
Other current assets	(433)	2,335	(1,713)
Accounts payable	(14,124)	5,932	(7,540)
Accrued liabilities	(4,613)	(725)	1,320
Cash-out deferred revenue	(10)	75	(249)
Other current liabilities	(373)	(127)	(2,898)
Net cash provided by operating activities	16,084	91,654	62,092
INVESTING ACTIVITIES:			
Decrease in restricted cash	3,470	2,752	22,551
Property, plant, and equipment:			
Capital expenditures	(19,023)	(9,939)	(29,114)
Proceeds from sale of property, plant and equipment			649
Net cash used by investing activities	(15,553)	(7,187)	(5,914)
FINANCING ACTIVITIES:			
Distributions to members	(52,642)	(94,000)	(59,172)
Capital contributions	20,133	13,076	3,920
Net cash used by financing activities	(32,509)	(80,924)	(55,252)
Increase (decrease) in cash and cash equivalents	(31,978)	3,543	926
Cash and cash equivalents at beginning of period	42,052	38,509	37,583
Cash and cash equivalents at end of period	$ 10,074	$ 42,052	$ 38,509

See accompanying notes to consolidated financial statements.

DISCOVERY PRODUCER SERVICES LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization and Description of Business

Unless the context clearly indicates otherwise, references in this report to we , our , us or similar language refer to Discovery Producer Services LLC and its wholly owned subsidiary, Discovery Gas Transmission LLC (DGT). We are a Delaware limited liability company formed on June 24, 1996 for the purpose of constructing and operating a 600 million cubic feet per day (MMcf/d) cryogenic natural gas processing plant near Larose, Louisiana and a 32,000 barrel per day (bpd) natural gas liquids fractionator near Paradis, Louisiana. DGT is a Delaware limited liability company formed on June 24, 1996 for the purpose of constructing and operating a natural gas pipeline from offshore deep water in the Gulf of Mexico to our gas processing plant in Larose, Louisiana. The mainline has a design capacity of 600 MMcf/d and consists of approximately 105 miles of pipe. We have since connected several laterals to the DGT pipeline to expand our presence in the Gulf.

At the beginning of the periods presented, we were owned 20% by Williams Energy, L.L.C. (a wholly owned subsidiary of The Williams Companies, Inc.), 40% by DCP Assets, LP (DCP) and 40% by Williams Partners Operating LLC (a wholly owned subsidiary of Williams Partners L.P) (WPZ). Williams Energy, L.L.C. is our operator. Herein, The Williams Companies, Inc. and its subsidiaries are collectively referred to as Williams.

On June 28, 2007, WPZ acquired the 20% interest in us previously held by Williams Energy, L.L.C. Hence, at December 31, 2007, we were, and continue to be, owned 60% by WPZ and 40% by DCP.

We evaluated our disclosure of subsequent events through the date, February 25, 2010, that our financial statements were filed.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation. The consolidated financial statements have been prepared based upon accounting principles generally accepted in the United States and include the accounts of the parent and our wholly owned subsidiary, DGT. Intercompany accounts and transactions have been eliminated.

Use of Estimates. The preparation of consolidated 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.

Estimates and assumptions used in the calculation of asset retirement obligations are, in the opinion of management, significant to the underlying amounts included in the consolidated financial statements. It is reasonably possible that future events or information could change those estimates.

Cash and Cash Equivalents. The cash and cash equivalent balance is primarily invested in funds with high-quality, short term securities and instruments that are issued or guaranteed by the U.S. government. These securities have maturities of three months or less when acquired.

Trade Accounts Receivable. Trade accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. We do not recognize an allowance for doubtful accounts at the time the revenue that generates the accounts receivable is recognized. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of the customers, and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. There was no allowance for doubtful accounts at December 31, 2009 and 2008.

Insurance Receivable. Hurricane Katrina damaged our pipeline and onshore facilities in 2005, and Hurricane Ike damaged the 30 mainline and 18 lateral in 2008. Expenditures incurred for the repair of these damages considered probable of recovery when incurred are recorded as insurance receivable. We expense expenditures up to the insurance deductible ($6.4 million in 2008), amounts not covered by insurance ($2.0 million in 2008) and amounts subsequently determined not to be recoverable.

Prepaid Insurance. Prepaid insurance represents the unamortized balance of insurance premiums. These payments are amortized on a straight line basis over the policy term.

Gas Imbalances. 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. This results in gas transportation imbalance receivables and payables which are recovered or repaid in cash, based on market-based prices, or through the receipt or delivery of gas in the future. Imbalance receivables and payables are included in Other current assets and Other current liabilities in the Consolidated Balance Sheets. Imbalance receivables are valued based on the lower of the current market prices or weighted average cost of natural gas in the system. Imbalance payables are valued at current market prices. Settlement of imbalances requires agreement between the pipelines and shippers as to allocations of volumes to specific transportation contracts and the timing of delivery of gas based on operational conditions. Pursuant to a settlement with our shippers issued by the Federal Energy Regulatory Commission (FERC) on February 5, 2008, if a cash-out refund is due and payable to a shipper during any year pursuant to Transporter s FERC Gas Tariff, shipper will be deemed to have immediately assigned its right to the refund amount to us.

Restricted Cash. Restricted cash within non-current assets relates to escrow funds contributed by our members for the construction of the Tahiti pipeline lateral expansion. The restricted cash is classified as non-current because the funds will be used to construct a long-term asset. The restricted cash is primarily invested in short-term money market accounts with financial institutions.

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. The natural gas and natural gas liquids maintained in the pipeline facilities necessary for their operation (line fill) are included in property, plant and equipment. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of 25 to 35 years. Expenditures for maintenance and repairs are expensed as incurred. Expenditures that extend the useful lives of the assets or increase their functionality are capitalized. The cost of property, plant and equipment sold or retired and the related accumulated depreciation is removed from the accounts in the period of sale or disposition. Gains and losses on the disposal of property, plant and equipment are recorded in the Statements of Income.

We record an asset and a liability equal to the present value of each expected future asset retirement obligation (ARO). The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as corresponding accretion expense included in operating income.

Revenue Recognition. Revenue for sales of products is recognized in the period of delivery, and revenues from the gathering, transportation and processing of gas are recognized in the period the service is provided based on contractual terms and the related natural gas and liquid volumes. DGT is subject to FERC regulations, and accordingly, certain revenues collected may be subject to possible refunds upon final orders in pending cases. DGT records rate refund liabilities considering its and other third parties regulatory proceedings, advice of counsel, estimated total exposure as discounted and risk weighted, and collection and other risks. There were no rate refund liabilities accrued at December 31, 2009 or 2008.

Impairment of Long-Lived Assets. We evaluate long-lived assets for impairment on an individual asset or asset group basis when events or changes in circumstances indicate that, in our management s judgment, the carrying value of such assets may not be recoverable. When such a determination has been made, 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 the carrying value is recoverable. If the carrying value is not recoverable, 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.

Income Taxes. For federal tax purposes, we have elected to be treated as a partnership with each member being separately taxed on its ratable share of our taxable income. This election, to be treated as a pass-through entity, also applies to our wholly owned subsidiary, DGT. Therefore, no income taxes or deferred income taxes are reflected in the consolidated financial statements.

Foreign Currency Transactions. 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 or losses which are reflected in the Consolidated Statements of Income.

Note 3. Related Party Transactions

We have various business transactions with our members and subsidiaries and affiliates of our members. Revenues include the following:

- sales to Williams of NGLs to which we take title and excess gas at current market prices for the products and

- processing and sales of natural gas liquids and transportation of gas and condensate for DCP s affiliates, Texas Eastern Corporation and ConocoPhillips Company.

The following table summarizes these related-party revenues during 2009, 2008 and 2007.

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Williams	$ 114,869	$ 207,782	$ 217,012
Texas Eastern Corporation	190	1,953	3,912
ConocoPhillips	295	259	36
Total	$ 115,354	$ 209,994	$ 220,960

We have no employees. Pipeline and plant operations are performed under operation and maintenance agreements with Williams. Most costs for materials, services and other charges are third-party charges and are invoiced directly to us. Operating and maintenance expenses affiliate includes the following:

- direct payroll and employee benefit costs incurred on our behalf by Williams, and

- rental expense under a 10-year leasing agreement for pipeline capacity through 2015 from Texas Eastern Transmission, LP (an affiliate of DCP)

Product costs and shrink replacement affiliate includes natural gas purchases from Williams for fuel and shrink requirements made at market rates at the time of purchase.

General and administrative expenses affiliate includes a monthly operation and management fee paid to Williams to cover the cost of accounting services, computer systems and management services provided to us.

We also pay Williams a project management fee to cover the cost of managing capital projects. This fee is determined on a project by project basis and is capitalized as part of the construction costs. A summary of the payroll costs and project fees charged to us by Williams and capitalized are as follows:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Capitalized labor	$ 280	$ 317	$ 222
Capitalized project fee	312	375	651
	$ 592	$ 692	$ 873

Note 4. Property, Plant, and Equipment

Property, plant, and equipment consisted of the following at December 31, 2009 and 2008:

	Years Ended December 31,		Estimated Depreciable Lives
	2009	2008	
	(In thousands)		
Property, plant, and equipment:			

Construction work in progress	$ 5,256	$ 76,302	
Buildings	5,055	5,054	25 35 years
Land and land rights	5,556	5,575	0 35 years
Transportation lines	320,956	305,172	25 35 years
Plant and other equipment	283,001	216,189	25 35 years
Total property, plant, and equipment	619,824	608,292	
Less accumulated depreciation	254,892	237,810	
Net property, plant, and equipment	$ 364,932	$ 370,482	

Commitments for construction and acquisition of property, plant, and equipment at Grand Isle 115 for an interconnect with ATP are approximately $223 thousand at December 31, 2009.

Our asset retirement obligations relate primarily to our offshore platform and pipelines and our onshore processing and fractionation facilities. At the end of the useful life of each respective asset, we are legally or contractually obligated to dismantle the offshore platform, properly abandon the offshore pipelines, remove the onshore facilities and related surface equipment and restore the surface of the property.

A rollforward of our asset retirement obligation for 2009 and 2008 is presented below.

	Years Ended December 31,	
	2009	2008
	(In thousands)	
Balance at January 1	$ 19,684	$ 12,118
Accretion expense	1,669	1,082
Estimate revisions	396	3,327
Liabilities incurred	1,576	3,157
Balance at December 31	$ 23,325	$ 19,684

Note 5. Leasing Activities

We lease the land on which the Paradis fractionator and the Larose processing plant are located. The initial term of each lease is 20 years with renewal options for an additional 30 years. We also have a ten-year leasing agreement for pipeline capacity from Texas Eastern Transmission, LP that includes renewal options and options to increase capacity which would also increase rentals. The future minimum annual rentals under these non-cancelable leases as of December 31, 2009 are payable as follows:

	(In thousands)
2010	$ 1,241
2011	1,241
2012	1,245
2013	1,245
2014	1,245
Thereafter	759
	$ 6,976

Total rent expense for 2009, 2008 and 2007, including a cancelable platform space lease and month-to-month leases, was $1.8 million, $1.6 million and $1.4 million, respectively.

Note 6. Financial Instruments, Concentrations of Credit Risk and Major Customers

Financial Instruments Fair Value

We used the following methods and assumptions to estimate the fair value of financial instruments:

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

Restricted cash. The carrying amounts reported in the consolidated balance sheets approximate fair value as these instruments have interest rates approximating market.

	2009		2008	
	Carrying	Fair	Carrying	Fair

	Amount	Value	Amount	Value
		(In thousands)		
Cash and cash equivalents	$10,074	$10,074	$42,052	$42,052
Restricted cash			3,470	3,470

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Concentrations of Credit Risk

Our cash equivalent balance is primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

At December 31, 2009, substantially all of our customer accounts receivable result from gas transmission services provided for our largest three customers. This concentration of customers may impact our overall credit risk either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic or other conditions. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly. Our credit policy and the relatively short duration of receivables mitigate the risk of uncollected receivables. We did not incur any credit losses on receivables during 2009 and 2008.

Major Customers

Williams accounted for approximately \$114.9 million (71%), \$208.0 million (86%), \$217.0 million (83%) respectively, of our total revenues in 2009, 2008 and 2007. These revenues were for the sale of NGLs received as compensation under processing contracts with third-party producers.

Note 7. Rate and Regulatory Matters

Rate and Regulatory Matters. Annually, DGT files a request with the FERC for a fuel lost-and-unaccounted-for gas percentage to be allocated to shippers for the upcoming fiscal year beginning July 1. On June 1, 2009, DGT filed to maintain a lost-and-unaccounted-for percentage of zero percent until July 1, 2010 and to retain the 2008 net system gains of \$5.4 million that are unrelated to the lost-and-unaccounted-for gas over recovered from its shippers. By Order dated June 30, 2009 the filing was approved. The approval was subject to a 30-day protest period, which passed without protest. As of December 31, 2009 and 2008, DGT has deferred amounts of \$211,000 and \$5.4 million, respectively, included in current accrued liabilities in the accompanying Consolidated Balance Sheets for unrecognized net system gains.

On February 25, 2009, DGT filed with the FERC to adjust its Hurricane Mitigation and Reliability Enhancement surcharge (HMRE). The HMRE was approved in DGT s rate case settlement in 2008. Normally, DGT files to establish a new HMRE no later than November 15 of each year, to be effective January 1 the following year. This filing was made out-of-cycle to recover approximately \$6.9 million in costs spent to repair a lateral displaced by Hurricane Ike. On March 30, 2009, the FERC issued an order accepting the revised HMRE surcharge of \$0.05/dt effective April 1, 2009.

On March 17, 2009, we and DGT filed a joint application to amend DGT s certificate and our limited jurisdiction certificate, to permit us to provide an additional 50,000 Dth per day of compression services to DGT at our Larose processing plant. DGT did not request any related change in rates. On August 28, 2009, the FERC issued an order granting the certificate amendment requests.

On November 13, 2009, DGT filed its annual HMRE surcharge adjustment. The filing proposed to reduce the surcharge from \$0.05 to \$0.0374 per Dt, effective January 1, 2010. The FERC approved the filing on December 23, 2009.

Environmental Matters. We are subject to extensive federal, state, and local environmental laws and regulations which affect our operations related to the construction and operation of our facilities. Appropriate governmental authorities may enforce these laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties, assessment and remediation requirements and injunctions as to future compliance. We have not been notified and are not currently aware of any material noncompliance under the various environmental laws and regulations.

Other. We are party to various other claims, legal actions and complaints arising in the ordinary course of business. Litigation, arbitration and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of

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amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our future liquidity or financial position.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Williams Partners L.P.
(Registrant)

By: Williams Partners GP LLC,
its general partner

By: /s/ Ted T. Timmermans
Ted T. Timmermans
Controller (Duly Authorized Officer and Principal Accounting Officer)

Date: February 25, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ STEVEN J. MALCOLM	President, Chief Executive Officer and	February 25, 2010
Steven J. Malcolm	Chairman of the Board (Principal Executive Officer)	
/s/ DONALD R. CHAPPEL	Chief Financial Officer and Director	
Donald R. Chappel	(Principal Financial Officer)	February 25, 2010
/s/ TED T. TIMMERMANS	Chief Accounting Officer and Controller	February 25, 2010
Ted T. Timmermans	(Principal Accounting Officer)	
/s/ ALAN S. ARMSTRONG*	Director	February 25, 2010
Alan S. Armstrong		
/s/ BILL Z. PARKER*	Director	February 25, 2010
Bill Z. Parker		
/s/ ALICE M. PETERSON*	Director	February 25, 2010

	Alice M. Peterson		
	/s/ H. MICHAEL KRIMBILL*	Director	February 25, 2010
	H. Michael Krimbill		
	/s/ PHILLIP D. WRIGHT*	Director	February 25, 2010
	Phillip D. Wright		
*By:	/s/ WILLIAM H. GAULT		
	William H. Gault *Attorney-in-fact*		February 25, 2010

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INDEX TO EXHIBITS

Exhibit Number	Description
§Exhibit 2.1	Purchase and Sale Agreement, dated April 6, 2006, by and among Williams Energy Services, LLC, Williams Field Services Group, LLC, Williams Field Services Company, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on April 7, 2006 as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No.001-32599)) and incorporated herein by reference.
§Exhibit 2.2	Purchase and Sale Agreement, dated November 16, 2006, by and among Williams Energy Services, LLC, Williams Field Services Group, LLC, Williams Field Services Company, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on November 21, 2006 as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No.001-32599)) and incorporated herein by reference.
§Exhibit 2.3	Purchase and Sale Agreement, dated June 20, 2007, by and among Williams Energy, L.L.C., Williams Energy Services, LLC and Williams Partners Operating LLC (filed on June 25, 2007 as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
§Exhibit 2.4	Purchase and Sale Agreement, dated November 30, 2007, by and among Williams Energy Services, LLC, Williams Field Services Group, LLC, Williams Field Services Company, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on December 3, 2007 as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 2.5	Contribution Agreement, dated as of January 15, 2010, by and among Williams Energy Services, LLC, Williams Gas Pipeline Company, LLC, WGP Gulfstream Pipeline Company, L.L.C., Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and, for a limited purpose, The Williams Companies, Inc, including exhibits thereto (filed on January 19, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 3.1	Certificate of Limited Partnership of Williams Partners L.P. (filed on May 2, 2005 as Exhibit 3.1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.2	Certificate of Formation of Williams Partners GP LLC (filed on May 2, 2005 as Exhibit 3.3 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
*Exhibit 3.3	Amended and Restated Agreement of Limited Partnership of Williams Partners L.P. (including form of common unit certificate), as amended by Amendments Nos. 1, 2, 3, 4, 5, and 6.
Exhibit 3.4	Amended and Restated Limited Liability Company Agreement of Williams Partners GP LLC (filed on August 26, 2005 as Exhibit 3.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.

Exhibit 4.1	Indenture, dated June 20, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and JPMorgan Chase Bank, N.A. (filed on June 20, 2006 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.2	Form of 7 $^{1}/2$% Senior Note due 2011 (filed on June 20, 2006 as Exhibit 1 to Rule 144A/Regulation S Appendix of Exhibit 4.1 attached to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.3	Certificate of Incorporation of Williams Partners Finance Corporation (filed on September 22, 2006 as Exhibit 4.5 to Williams Partners L.P. s registration statement on Form S-3 (File No. 333-137562)) and incorporated herein by reference.
Exhibit 4.4	Bylaws of Williams Partners Finance Corporation (filed on September 22, 2006 as Exhibit 4.6 to Williams Partners L.P. s registration statement on Form S-3 (File No. 333-137562)) and incorporated herein by reference.
Exhibit 4.5	Indenture, dated December 13, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and The Bank of New York (filed on December 19, 2006 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.

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Exhibit Number	Description
Exhibit 4.6	Form of 7 1/4% Senior Note due 2017 (filed on December 19, 2006 as Exhibit 1 to Rule 144A/Regulation S Appendix of Exhibit 4.1 attached to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.7	Indenture, dated as of February 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 10, 2010 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.8	Registration Rights Agreement, dated as of February 9, 2010, among Williams Partners L.P. and Barclays Capital Inc. and Citigroup Global Markets Inc., each acting on behalf of themselves and the initial purchasers listed on Schedule I thereto (filed on February 10, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.9	Limited Call Right Forbearance Agreement, dated as of February 17, 2010, by and between Williams Partners L.P. and Williams Partners GP LLC (filed on February 22, 2010 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.10	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee with regard to Northwest Pipeline s 7.125% Debentures, due 2025 (filed September 14, 1995 as Exhibit 4.1 to Northwest Pipeline Corporation s Form S-3 (File No. 033-62639)) and incorporated herein by reference.
Exhibit 4.11	Indenture, dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee, with regard to Northwest Pipeline s $175 million aggregate principal amount of 7.00% Senior Notes due 2016 (filed on June 23, 2006 as Exhibit 4.1 to Northwest Pipeline Corporation s Form 8-K (File. No. 001-07414) and incorporated herein by reference.
Exhibit 4.12	Indenture, dated as of April 5, 2007, between Northwest Pipeline Corporation and The Bank of New York (filed on April 5, 2007 as Exhibit 4.1 to Northwest Pipeline Corporation s Form 8-K (File No. 001-07414)) and incorporated herein by reference.
Exhibit 4.13	Indenture, dated May 22, 2008, between Northwest Pipeline GP and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Northwest Pipeline GP s Form 8-K File No. 001-07414)) and incorporated herein by reference.
Exhibit 4.14	Registration Rights Agreement, dated as of May 23, 2008, among Northwest Pipeline GP and Banc of America Securities, LLC, BNP Paribas Securities Corp, and Greenwich Capital Markets, Inc., acting on behalf of themselves and the several initial purchasers listed on Schedule I thereto (filed on May 23, 2008 as Exhibit 10.1 to Northwest Pipeline GP s Form 8-K (File No. 001-07414)) and incorporated herein by reference.
Exhibit 4.15	

	Senior Indenture, dated as of July 15, 1996 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on April 2, 1996 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-3 (File No. 333-02155)) and incorporated herein by reference.
Exhibit 4.16	Senior Indenture, dated as of January 16, 1998, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on September 8, 1997 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-3 (File No. 333-27311)) and incorporated herein by reference.
Exhibit 4.17	Indenture, dated as of August 27, 2001, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on November 8, 2001 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-4 (File No. 333-72982)) and incorporated herein by reference.
Exhibit 4.18	Indenture, dated as of July 3, 2002, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed August 14, 2002 as Exhibit 4.1 to The Williams Companies Inc. s Form 10-Q (File No. 001-07584)) and incorporated herein by reference.
Exhibit 4.19	Indenture, dated December 17, 2004, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee (filed on December 21, 2004 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 4.20	Indenture, dated as of April 11, 2006, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee with regard to Transcontinental Gas Pipe Line s $200 million aggregate principal amount of 6.4% Senior Note due 2016 (filed on April 11, 2006 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 4.21	Indenture, dated May 22, 2008, between Transcontinental Gas Pipe Line Corporation and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.

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Exhibit Number	Description
Exhibit 4.22	Registration Rights Agreement, dated as of May 22, 2008, among Transcontinental Gas Pipe Line Corporation and Banc of America Securities LLC, Greenwich Capital Markets, Inc., and J. P. Morgan Securities Inc., acting on behalf of themselves and the several initial purchasers listed on Schedule I thereto (filed on May 23, 2008 as Exhibit 10.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 10.1	Credit Agreement, dated as of December 11, 2007, by and among Williams Partners L.P., the lenders party hereto, Citibank, N.A., as Administrative Agent and Issuing Bank, and The Bank of Nova Scotia, as Swingline Lender (filed on December 17, 2007 as Exhibit 10.5 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.2	Omnibus Agreement, among Williams Partners L.P., Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Partners Holdings LLC, Williams Discovery Pipeline LLC, Williams Partners GP LLC, Williams Partners Operating LLC and (for purposes of Articles V and VI thereof only) The Williams Companies, Inc. (filed on August 26, 2005 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.3	Amendment No. 1 to Omnibus Agreement among Williams Partners L.P., Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Partners Holdings LLC, Williams Discovery Pipeline LLC, Williams Partners GP LLC, Williams Partners Operating LLC and (for purposes of Articles V and VI thereof only) The Williams Companies, Inc. (filed on April 20, 2009 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.4	Omnibus Agreement, dated as of February 17, 2010, by and between The Williams Companies, Inc. and Williams Partners L.P. (filed on February 22, 2010 as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.5	Contribution, Conveyance and Assumption Agreement, dated August 23, 2005, by and among Williams Partners L.P., Williams Energy, L.L.C., Williams Partners GP LLC, Williams Partners Operating LLC, Williams Energy Services, LLC, Williams Discovery Pipeline LLC, Williams Partners Holdings LLC and Williams Natural Gas Liquids, Inc. (filed on August 26, 2005 as Exhibit 10.3 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.6	Contribution, Conveyance and Assumption Agreement, dated June 20, 2006, by and among Williams Energy Services, LLC, Williams Field Services Company, LLC, Williams Field Services Group, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on June 20, 2006 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.7	Contribution, Conveyance and Assumption Agreement, dated June 20, 2006, by and among Williams Field Services Company, LLC and Williams Four Corners LLC (filed on June 20, 2006 as Exhibit 10.4 to Williams Partners L.P. s current report on Form 8-K (File

No. 001-32599) and incorporated herein by reference.

Exhibit 10.8	Contribution, Conveyance and Assumption Agreement, dated December 13, 2006, by and among Williams Energy Services, LLC, Williams Field Services Company, LLC, Williams Field Services Group, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on December 19, 2006 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.9	Contribution, Conveyance and Assumption Agreement, dated December 11, 2007, by and among Williams Energy Services, LLC, Williams Field Services Company, LLC, Williams Field Services Group, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on December 17, 2007 as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.10	Conveyance, Contribution and Assumption Agreement, dated as of February 17, 2010, by and among Williams Energy Services, LLC, Williams Gas Pipeline Company, LLC, WGP Gulfstream Pipeline Company, L.L.C., Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on February 22, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.11	Assignment Agreement, dated December 11, 2007, by and between Williams Field Services Company, LLC and Wamsutter LLC (filed on December 17, 2007 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.

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Exhibit Number	Description
Exhibit 10.12	Third Amended and Restated Limited Liability Company Agreement for Discovery Producer Services LLC (filed on June 24, 2005 as Exhibit 10.7 to Amendment No. 1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 10.13	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement for Discovery Producer Services LLC (filed on August 8, 2006 as Exhibit 10.6 to Williams Partners L.P. s quarterly report on Form 10-Q (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.14	Amendment No. 2 to Third Amended and Restated Limited Liability Company Agreement for Discovery Producer Services LLC (filed on August 6, 2009 as Exhibit 10.3 to Williams Partners L.P. s quarterly report on Form 10-Q (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.15	Amended and Restated Limited Liability Company Agreement of Wamsutter LLC, dated December 1, 2007, by and between Williams Field Services Company, LLC and Williams Partners Operating LLC (filed on December 17, 2007 as Exhibit 10.3 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.16	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Wamsutter LLC, dated as of February 17, 2010, by and between Williams Field Services Company, LLC and Williams Partners Operating LLC (filed on February 22, 2010 as Exhibit 10.4 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
#Exhibit 10.17	Williams Partners GP LLC Long-Term Incentive Plan (filed on August 26, 2005 as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
#Exhibit 10.18	Amendment to the Williams Partners GP LLC Long-Term Incentive Plan, dated November 28, 2006 (filed on December 4, 2006 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
#Exhibit 10.19	Amendment No. 2 to the Williams Partners GP LLC Long-Term Incentive Plan, dated December 2, 2008 (filed on February 26, 2009, as Exhibit 10.4 to Williams Partners L.P. s annual report on Form 10-K (File No. 001-32599)) and incorporated herein by reference.
#Exhibit 10.20	Director Compensation Policy dated November 29, 2005, as revised May 28, 2009 (filed on August 6, 2009 as Exhibit 10.2 to Williams Partners L.P. s quarterly report on Form 10-Q (File No. 001-32599)) and incorporated herein by reference.
#Exhibit 10.21	Form of Grant Agreement for Restricted Units (filed on December 1, 2005 as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.

Exhibit 10.22	Administrative Services Agreement between Northwest Pipeline Services LLC and Northwest Pipeline GP, dated October 1, 2007 (filed on January 30, 2008 as Exhibit 10.1 to Williams Pipeline Partners L.P. s Form 8-K (File No. 001-33917) and incorporated herein by reference).
Exhibit 10.23	Administrative Services Agreement, dated as of February 17, 2010, by and between Transco Pipeline Services LLC and Transcontinental Gas Pipe Line Company, LLC (filed on February 22, 2010 as Exhibit 10.3 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.24	Credit Agreement, dated as of February 17, 2010, by and among Williams Partners L.P., Transcontinental Gas Pipe Line Company, LLC, Northwest Pipeline GP, the lenders party thereto and Citibank, N.A., as Administrative Agent (filed on February 22, 2010 as Exhibit 10.5 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
*Exhibit 12	Computation of Ratio of Earnings to Fixed Charges
*Exhibit 21	List of subsidiaries of Williams Partners L.P.
*Exhibit 23.1	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
*Exhibit 23.2	Consent of Independent Auditors, Ernst & Young LLP.
*Exhibit 24	Power of attorney.
*Exhibit 31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
*Exhibit 31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
*Exhibit 32	Section 1350 Certifications of Chief Executive Officer and Chief Financial Officer.

* Filed herewith.

§ Pursuant to item 601(b) (2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

\# Management contract or compensatory plan or arrangement.