Williams Partners L.P.
Form 10-K
February 28, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Form 10-K

(Mark One)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1933** **For the fiscal year ended December 31, 2006**
	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 *(State or Other Jurisdiction of Incorporation or Organization)*	**20-2485124** *(IRS Employer Identification No.)*
One Williams Center, Tulsa, Oklahoma *(Address of Principal Executive Offices)*	**74172-0172** *(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 o No þ

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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

Large accelerated filer o Accelerated filer þ Non-accelerated filer 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 $417,974,414. This figure excludes common units beneficially owned by the directors and executive officers of Williams Partners GP LLC, our general partner.

The registrant had 25,553,306 common units, 6,805,492 Class B units and 7,000,000 subordinated units outstanding as of February 27, 2007.

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.

¢/MMBtu: Cents per one million Btus.

MMBtu: One million Btus.

MMBtu/d: One million Btus per day.

MMcf: One million cubic feet. (Volumes of natural gas are generally reported in terms of cubic feet).

MMcf/d: One million cubic feet per day.

NGLs: Natural gas liquids.

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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WILLIAMS PARTNERS L.P.
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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 Discovery, in which we own a 40% interest. Discovery consists of Discovery Producer Services LLC and its wholly owned subsidiary, Discovery Gas Transmission LLC. When we refer to Discovery by name, we are referring exclusively to its 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. From time-to-time, we may also file registration and related statements pertaining to equity or debt offerings. 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.*

We make available free of charge on or through our Internet website at *http://www.williamslp.com*, 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. 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.

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

GENERAL

We are a publicly traded Delaware limited partnership formed by The Williams Companies, Inc., or Williams, in February 2005, to own, operate and acquire a diversified portfolio of complementary energy assets. We are principally engaged in the business of gathering, transporting, processing and treating natural gas and the fractionating and storing of natural gas liquids. Fractionation is the process by which a mixed stream of natural gas liquids is separated into its constituent products, such as ethane, propane and butane. These 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.

Operations of our businesses are located in the United States. We manage our business and analyze our results of operations on a segment basis. Our operations are divided into three business segments:

Gathering and Processing West. Our Gathering and Processing West segment includes Williams Four Corners LLC, or Four Corners, which owns a 3,500 mile-natural gas gathering system, including three natural gas processing plants and two natural gas treating plants, located in the San Juan Basin in Colorado and New Mexico. These assets generate revenues by providing natural gas gathering, transporting, processing and treating services to customers under a range of contractual arrangements.

Gathering and Processing Gulf. Our Gathering and Processing Gulf segment includes our equity investment in Discovery and the Carbonate Trend gathering pipeline. We own a 40% interest in

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Discovery, which is operated by Williams. Discovery owns an integrated natural gas gathering and transportation pipeline system extending from offshore in the Gulf of Mexico to a natural gas processing facility and a natural gas liquids fractionator in Louisiana. Our Carbonate Trend gathering pipeline is an unregulated sour gas gathering pipeline consisting of approximately 34 miles of pipeline off the coast of Alabama. These assets generate revenues by providing natural gas gathering, transporting and processing services and integrated natural gas fractionating services to customers under a range of contractual arrangements.

NGL Services. Our NGL Services segment includes three integrated natural gas liquids storage facilities and a 50% undivided interest in a natural gas liquids fractionator near Conway, Kansas. These assets generate revenues by providing stand-alone natural gas liquids fractionation and storage services using various fee-based contractual arrangements where we receive a fee or fees based on actual or contracted volumetric measures.

We account for our 40% interest in Discovery as an equity investment and, therefore, do not consolidate its financial results.

Our assets were owned by Williams prior to the initial public offering (IPO) of our common units in August 2005 and our acquisition of Four Corners in 2006. Williams indirectly owns an approximate 21% limited partnership interest in us and all of our 2% general partner interest.

Williams is an integrated energy company with 2006 revenues in excess of $11.8 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.

RECENT EVENTS

Acquisition of Four Corners. In 2006, in two separate transactions, we acquired 100% of Four Corners from Williams. On June 20, 2006, we acquired a 25.1% membership interest in Four Corners for aggregate consideration of $360.0 million. On December 13, 2006, we acquired the remaining 74.9% membership interest for aggregate consideration of $1.223 billion. These two transactions were financed with the following debt and equity issuances.

Issuance of Common Units. On June 20 and December 13, 2006, respectively, we sold 7,590,000 and 8,050,000 common units (including 990,000 and 1,050,000 common units pursuant to the underwriters over-allotment purchase option) in public offerings. We received net proceeds of approximately $227.1 million and $293.7 million, respectively, from the sale of the common units after deducting underwriting discounts but before estimated offering expenses.

Issuance of Common Units and Class B units in a Private Placement. On December 13, 2006, we sold 2,905,030 common units and 6,805,492 unregistered Class B units in a private placement. We received net proceeds of approximately $346.5 million after deducting placement fees but before estimated offering expenses. The Class B units are convertible into common units on a one-for-one basis upon the approval of a majority of the votes cast by common unitholders, provided that the total number of votes cast is at least a majority of common units eligible to vote (excluding common units held by Williams and its affiliates).

Issuance of Senior Unsecured Notes. On June 20 and December 13, 2006, respectively, we issued $150.0 million and $600.0 million aggregate principal amount of 7.5% and 7.25% senior unsecured notes due 2011 and 2017, respectively. We received net proceeds of approximately $146.8 million and $590.0 million, respectively, from the sale of the senior unsecured notes after deducting initial purchaser discounts and estimated offering expenses.

Williams New Credit Facility. In May 2006, Williams replaced its $1.275 billion secured credit facility with a $1.5 billion unsecured credit agreement. The new facility contains similar terms and covenants as the prior facility. The new credit agreement is available for borrowings and letters of credit and will continue to allow us to borrow up to $75.0 million for general partnership purposes, including acquisitions, but only to the

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extent that sufficient amounts remain unborrowed by Williams and its other subsidiaries. Please read Financial Condition and Liquidity Credit Facilities for more information.

FINANCIAL INFORMATION ABOUT SEGMENTS

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

NARRATIVE DESCRIPTION OF BUSINESS

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.

Gathering and Processing West

Our Gathering and Processing West segment is comprised of our Four Corners assets, which include:

- A 3,500-mile natural gas gathering system in the San Juan Basin in New Mexico and Colorado with a capacity of two Bcf/d;

- 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 760 MMcf/d; and

- the Milagro and Esperanza natural gas treating plants in New Mexico, which have a combined carbon dioxide treating capacity of 750 MMcf/d.

Our Four Corners customers are primarily natural gas producers in the San Juan Basin. We provide our customers with a full range of gathering, processing and treating services. Fee-based gathering, processing and treating services accounted for approximately 72% of our Gathering and Processing West segment s total revenue less its product cost and shrink replacement costs and expenses for the year ended December 31, 2006. The remaining 28% of the segments total revenues less product cost and shrink replacement for the year ended December 31, 2006 was derived from the sale of NGLs received by Four Corners as consideration for processing services.

For the twelve months ended December 31, 2006, our Four Corners gathering system gathered approximately 37% of the natural gas produced in the San Juan Basin and 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 reservoirs with approximately 60% coming from coal bed reservoirs. We are currently the only company in the basin that is the owner and operator of both major conventional natural gas and coal bed methane gathering, processing and treating facilities in the San Juan Basin. Despite the topographically challenging terrain, we have gathering pipelines throughout most of the San Juan Basin.

Four Corners Natural Gas Gathering System

Our Four Corners natural gas gathering pipeline system consists of:

- 3,500 miles of 2-inch to 30-inch diameter natural gas gathering pipelines with capacity of two Bcf/d and approximately 6,400 receipt points; and

- Over 400,000 horsepower of compression comprised of distributed gathering compression, major gathering station compression and plant compression. A substantial portion of this compression is operated by a third-party.

We generally charge a fee on the volume of natural gas gathered on our Four Corners pipeline system. We do not, however, take title to the natural gas gathered on the system other than natural gas we retain for fuel and purchases for shrinkage.

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Four Corners Processing and Treating Plants

Natural Gas Processing Plants

Our Gathering and Processing West segment includes three natural gas processing plants with a combined processing capacity of 760 MMcf/d and combined NGL production capacity of 41,000 bpd. We own and operate these three plants.

The Ignacio natural gas processing plant was constructed in 1956 and is located near Durango, Colorado. Williams acquired the plant in 1983 in connection with its acquisition of Northwest Energy. The primary processing components of the Ignacio plant were installed in 1984 and were subsequently upgraded and expanded in 1999. The Ignacio plant has one cryogenic train with 55,000 horsepower of compression and processing capacity of 450 MMcf/d. The Ignacio plant has outlet connections to the El Paso Natural Gas, Transwestern and Williams Northwest Pipeline systems. These pipelines serve markets throughout most of the western United States. The plant has an NGL production capacity of 22,000 bpd. Most of the NGLs are shipped via the Mid-America Pipeline (MAPL) system to Gulf Coast markets, but some NGLs we retain are fractionated at Ignacio and distributed locally via trucks. Ignacio also produces liquefied natural gas, which is distributed via truck. The Ignacio plant is able to recover approximately 95% of the ethane contained in the natural gas stream and nearly all of the propane and heavier NGLs.

The Kutz and Lybrook gas processing plants, located in Bloomfield and Lybrook, New Mexico, respectively, have a combined processing capacity of 310 MMcf/d. These plants have an aggregate 67,000 horsepower of compression and have a combined NGL production capacity of 19,000 bpd. The NGLs are shipped via the MAPL pipeline system to Gulf Coast markets, but some liquids we retain are fractionated at Lybrook and distributed locally via truck. The Kutz plant has gas outlets to the El Paso Natural Gas, PNM and Transwestern pipeline systems. The Lybrook plant connects to the PNM pipeline. The Kutz and Lybrook plants are able to recover approximately 55% and 80%, respectively, of the ethane contained in the natural gas stream.

Treating Plants

Coal bed methane sources typically contain high levels of carbon dioxide that must be reduced to 2% or less for transportation through pipelines to end markets. Our Gathering and Processing West segment includes two natural gas treating plants, the Milagro and Esperanza plants, which are located in New Mexico and have a combined carbon dioxide treating capacity of 750 MMcf/d. We own and operate these two plants. The Milagro treating plant can deliver natural gas to the El Paso Natural Gas, Transwestern, Southern Trails and PNM pipelines. The Esperanza treating plant treats coal bed methane volumes and removes carbon dioxide from the gas stream upstream of the Milagro plant.

Four Corners charges a fee for the volume of natural gas treated at its facilities and does not take gas as payment for its treating services, other than for the reimbursement of gas used or lost during the treating of natural gas.

Four Corners Customers and Contracts

Customers. ConocoPhillips fee-based gathering and processing revenue accounted for approximately 24% of this segment s total revenues. Total revenues are comprised of product sales and fee-based gathering and processing revenues. In any given period, our product sales revenues can vary significantly depending on commodity prices and the extent to which we purchase third-party processing customer s NGLs. ConocoPhillips fee-based gathering and processing revenue accounted for 50% of this segment s total fee-based gathering and processing revenues, including revenues attributable to Burlington Resources prior to its acquisition by ConocoPhillips on March 31, 2006.

Additionally, product sales to a subsidiary of Williams, to which Four Corners sells substantially all of the NGLs it retains under its keep-whole and percent-of-liquids contracts, accounted for approximately 45% of the segment s total revenues for the year ended December 31, 2006. This amount includes NGL sales related to third-party processing customers NGLs that Four Corners purchases.

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Contracts. We provide our Four Corners customers with a full range of gathering, processing and treating services. These services are usually provided to each customer under long-term contracts with applicable acreage dedications, reserve dedications, or both, for the life of the contract. Our portfolio of Four Corners natural gas processing agreements includes the following types of contracts:

Keep-whole. Under keep-whole contracts, we (1) process natural gas produced by customers, (2) retain some or all of the extracted NGLs as compensation for our services, (3) replace the Btu content of the retained NGLs that were separated during processing with natural gas purchases, also known as shrink replacement gas, and (4) deliver an equivalent Btu content of natural gas to customers at the plant outlet. We, in turn, sell the retained NGLs to a subsidiary of Williams, which serves as a purchaser for those NGLs at market prices. For the year ended December 31, 2006, 38% of our Gathering and Processing West segment s processing volumes were under keep-whole contracts.

Percent-of -liquids. Under percent-of-liquids processing contracts, we (1) process natural gas produced by customers, (2) deliver to customers an agreed-upon percentage of the extracted NGLs, (3) retain a portion of the extracted NGLs as compensation for our services and (4) deliver natural gas to customers at the plant outlet. Under this type of contract, we are not required to replace the Btu content of the retained NGLs that were extracted during processing. We sell the retained NGLs to a subsidiary of Williams, which serves as a purchaser for those NGLs at market prices. For the year ended December 31, 2006, 12% of the segment s processing volumes were under percent-of-liquids contracts.

Fee-based. Under fee-based contracts, we receive revenue based on the volume of natural gas processed and the per-unit fee charged, and retain none of the extracted NGLs. For the year ended December 31, 2006, 14% of the segment s processing volumes were under fee-based contracts.

Fee-based and keep-whole. These contracts have both a per-unit fee component and a keep-whole component. The relative proportions of the fee component and the keep-whole component vary from contract to contract, with the keep-whole component never consisting of more than 50% of the total extracted NGLs. For the year ended December 31, 2006, 36% of the segment s processing volumes were under these fee-based and keep-whole contracts.

Competition

Our Four Corners pipeline system competes with other delivery options available to producers in the San Juan Basin. We generally compete with other gathering systems and interconnecting gas processing and treating facilities, some of which may have the same owner. The Enterprise system is comprised of approximately 5,500 miles of gathering lines and one processing plant. Enterprise owns and operates primarily conventional natural gas gathering and processing facilities in the San Juan Basin. The Red Cedar system consists of approximately 900 miles of gathering lines, and is a joint venture between the Southern Ute Indian tribe and Kinder Morgan Energy Partners. The TEPPCO system consists of 400 miles of gathering lines. Red Cedar and TEPPCO own and operate primarily coal bed methane gathering and treating facilities in the San Juan Basin.

Gas Supply

All of our contracts with major customers contain certain production dedications whereby natural gas produced from a particular area and/or group of receipt points may only flow to our Four Corners system for the life of the contract. Those contracts also contain provisions requiring the connection of newly drilled wells within dedicated areas to our Four Corners system. 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. For example, Four Corners is in active negotiations with several customers to renew gathering, processing and treating contracts that are in evergreen status and that represent approximately 9% of our total revenues for the year ended December 31, 2006. We anticipate that additional well connects, together with sustained drilling activity, other expansion opportunities and production enhancement activities by producers, will substantially offset the impact of normal decline in gathered and processed volumes or even temporarily

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increase these volumes. We have also, on occasion, successfully pursued customers connected to competing gathering systems when the customer s contract with the competing gathering system expired.

Gathering and Processing Gulf

Our Gathering and Processing Gulf segment is comprised of our 40% interest in Discovery and the Carbonate Trend gathering pipeline.

Discovery General

We own a 40% interest in Discovery, which in turn owns:

- a 283-mile natural gas gathering and transportation pipeline system, located primarily off the coast of Louisiana in the Gulf of Mexico, with a mainline capacity, certified by the U.S. Federal Energy Regulatory Commission (the FERC), of approximately 600 MMcf/d with six delivery points connected to major interstate and intrastate pipeline systems;

- a cryogenic natural gas processing plant in Larose, Louisiana;

- a fractionator in Paradis, Louisiana; and

- a 22-mile mixed NGL pipeline connecting the gas processing plant to the fractionator.

Additionally, Discovery has signed definitive agreements with Chevron, Total and Statoil to construct an approximate 35-mile gathering pipeline lateral to connect Discovery s existing pipeline system to these producers production facilities for the Tahiti prospect in the deepwater region of the Gulf of Mexico. The Tahiti pipeline lateral expansion is expected to have a design capacity of approximately 200 MMcf/d, and its anticipated completion date is May 2007, with first gas flowing in the first half of 2008.

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. Accordingly, this equity investment is considered part of our Gathering and Processing Gulf segment.

Discovery Natural Gas Pipeline System

Transportation and Gathering Natural Gas Pipeline. The mainline of the Discovery pipeline system consists of a 105-mile, 30-inch diameter natural gas and condensate pipeline, which begins at a platform owned by a third party and located in the offshore Louisiana Outer Continental Shelf at Ewing Bank 873. It extends northerly to the Larose gas processing plant and a four-mile, 20-inch natural gas pipeline that connects the Larose plant to the Texas Eastern Pipeline. Approximately 66 miles of the mainline is located offshore in water depths ranging from approximately 40 to 800 feet. Producers have dedicated their production from approximately 60 offshore blocks to Discovery. Each block represents an area of 5,760 acres (nine square miles). The mainline has a FERC-certificated capacity of approximately 600 MMcf/d.

The Discovery system connects to six natural gas pipeline systems, two of which provide 1.6 Bcf/d of takeaway capacity: the Bridgeline system, which serves southern Louisiana and connects to the Henry Hub natural gas market point, the Texas Eastern Pipeline system, which serves markets from Texas to the northeastern United States and Gulfsouth, which provides gas markets to the entire gulf coast region. Additionally, Discovery completed a market expansion project in June 2005 that connects Discovery to three additional pipeline systems: Tennessee Gas Pipeline, Columbia Gulf Transmission and Transcontinental Gas Pipe Line, or Transco. Together, these three pipeline systems provide up to an additional 500 MMcf/d of takeaway capacity. This market expansion project, consisting of approximately 40 miles of 20-inch diameter pipe extending from the Larose processing plant to Pointe Au Chien, Louisiana and Old Lady Lake, Louisiana has a FERC-certificated capacity of approximately 150 MMcf/d. Discovery s interconnections allow producers to benefit from flexible and diversified access to a variety of natural gas markets from the Gulf of Mexico to the eastern United States.

Shallow Water/Onshore Gathering. Discovery also owns shallow water and onshore gathering assets that consist of:

90 miles of offshore laterals with pipeline diameters ranging from 12 inches to 20 inches with connections to the mainline. These shallow water laterals are located in water depths ranging from approximately 50 to 360 feet. The FERC regulates 60 miles of Discovery s 90 miles of shallow water laterals;

a fixed-leg shelf production handling facility installed at Grand Isle 115. The platform facility allows for the injection of gas and condensate into the pipeline and is equipped with a production handling facility; and

a five-mile onshore gathering lateral with 20-inch diameter pipe that extends from a production area north of the Larose gas processing plant directly to the plant. The FERC does not regulate this lateral.

A Chevron-owned gathering system also connects to the Larose gas processing plant.

Deepwater Gathering. Discovery s deepwater gathering assets, which are located in water depths of greater than 1,000 feet, consist of 73 miles of gathering laterals, with pipeline diameters ranging from eight inches to 16 inches that extend to deepwater producing areas in the Gulf of Mexico such as the Morpeth prospect, Allegheny prospect and Front Runner prospect. The maximum water depth of these deepwater laterals is approximately 3,200 feet. Additionally, Discovery has signed definitive agreements to construct a gathering pipeline lateral to connect Discovery s existing pipeline system to certain producers production facilities for the Tahiti prospect described above. The FERC does not regulate any of Discovery s deepwater laterals.

Larose Gas Processing Plant

Discovery s cryogenic gas processing plant is located near Larose, Louisiana at the onshore terminus of Discovery s natural gas pipeline and has a design capacity of approximately 600 MMcf/d. The plant was placed in service in January 1998 and is located on land that Discovery leases from a third party. The initial term of the lease is 20 years and is renewable for ten-year intervals thereafter at Discovery s option for up to a total of 50 years.

The Larose plant is able to recover over 90% of the ethane contained in the natural gas stream and effectively 100% of the propane and heavier liquids. In addition, the processing plant is able to reject ethane down to effectively 0% when justified by market economics, while retaining a propane recovery rate of over 95% and butanes and heavier liquids recovery rates of effectively 100%. The Larose plant consumes very low amounts of natural gas as fuel, using only approximately 1.4% of the volume of natural gas processed.

In addition to its gas processing activities, the Larose plant generates additional revenues by charging separate fees for ancillary services, such as dehydration and condensate separation and stabilization. Producers may also contract with Discovery for transportation of condensate from offshore production handling facilities and upon separation and stabilization, to a third party s oil gathering pipeline and barge facility. Discovery also provides compression services for a third party s onshore gathering system that connects to Discovery s onshore lateral.

Paradis Fractionation Facility

The fractionator is located onshore near Paradis, Louisiana. The fractionator and mixed NGL pipeline went into service in January 1998 and is located on land that Discovery leases from a third party. The initial term of the lease is 20 years and is renewable for ten-year intervals thereafter at Discovery s option for up to a total of 50 years. The Paradis fractionator is designed to fractionate 32,000 bpd of mixed NGLs and is expandable to 42,000 bpd. In 2006, Discovery fractionated an average of 15,139 bpd of mixed NGLs. All products can be delivered through the Chevron

TENDS NGL pipeline system, and propane and heavier products may be transported by truck or railway.

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Discovery fractionates NGLs for third party customers and for itself, and typically it receives title to approximately one-half of the mixed NGL volumes leaving the Larose plant. A subsidiary of Williams markets substantially all of the NGLs and excess natural gas to which Discovery takes title by purchasing them from Discovery and reselling them to end-users. Discovery fractionates third party NGL volumes for a fractionation fee, which typically includes a base fractionation fee per gallon that is subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs on a monthly basis and labor costs on an annual basis, which are the principal variable costs in NGL fractionation. As a result, Discovery is generally able to pass through increases in those fractionation expenses to its customers.

Discovery Management

Currently, Discovery is owned 40% by us, 20% by Williams and 40% by DCP Midstream, LLC (DCP). Discovery is managed by a three-member management committee consisting of representation from each of the three owners. The members of the management committee have voting power that corresponds to the ownership interest of the owner they represent. However, except under limited circumstances, all actions and decisions relating to Discovery require the unanimous approval of the owners. Discovery must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval, will determine the amount of such distributions. In addition, the owners are required to offer to Discovery all opportunities to construct pipeline laterals within an area of interest.

Discovery Customers and Contracts

Customers. Product sales to a subsidiary of Williams, which purchases substantially all of the NGLs and excess natural gas to which Discovery takes title, accounted for approximately 75.3% of Discovery s revenues for the year ended December 31, 2006. This amount includes NGL sales related to third-party processing customers elections to have Discovery purchase their NGLs. In any given period, these product sales revenues can vary significantly depending on commodity prices and the extent to which third-party processing customer s elect to have Discovery purchase their NGLs.

Texas Eastern Transmission Company (TETCO) accounted for approximately 25% of Discovery s fee-based, transportation, gathering and processing, fractionation and related revenues. TETCO s revenues related to the open seasons, which provided outlets for natural gas that was stranded following damage to third-party facilities during hurricanes Katrina and Rita. In October 2006, Discovery signed a one-year contract with TETCO. Discovery s other customers are primarily offshore natural gas producers. Discovery provides these customers with wellhead to market delivery options by offering a full range of services including gathering, transportation, processing and fractionation. Discovery also has the ability to provide its customers with other specialized services, such as offshore production handling, condensate separation and stabilization and dehydration.

Contracts. Discovery s wholly owned subsidiary, Discovery Gas Transmission, owns the mainline and the FERC-regulated laterals, which generate revenues through a tariff on file with the FERC for several types of service: traditional firm transportation service with reservation fees (although no current shippers have elected this service); firm transportation service on a commodity basis with reserve dedication; and interruptible transportation service. In addition, for any of these general services, Discovery Gas Transmission has the authority to negotiate a specific rate arrangement with an individual shipper and has several of these arrangements currently in effect.

Discovery s maximum regulated rate for mainline transportation is scheduled to decrease in 2008. At that time, Discovery may be required to reduce the mainline transportation portion of the rate on any of its contracts that have rates above the new reduced rate. This could reduce the revenues generated by Discovery. Discovery may elect to file a rate case with the FERC to alter this scheduled reduction. However, if filed, a rate case may not be successful in even partially preventing the scheduled rate reduction. Please read FERC Regulation.

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Discovery s portfolio of processing contracts includes the following types of contracts:

Fee-based. Under fee-based contracts, Discovery receives revenue based on the volume of natural gas processed and the per-unit fee charged.

Percent-of-liquids. Under percent-of-liquids gas processing contracts, Discovery (1) processes natural gas for customers, (2) delivers to customers an agreed upon percentage of the NGLs extracted in processing and (3) retains a portion of the extracted NGLs. Discovery generates revenue from the sale of these retained NGLs to a subsidiary of Williams at market prices. Some of Discovery s contracts have a bypass option, which is explained below under Operation and Contract Optimization.

Operation and Contract Optimization

Long-haul natural gas pipelines, generally interstate pipelines that serve end use markets, publish specifications for the maximum NGL content of the natural gas that they will transport. Normally, NGLs must be removed from the natural gas stream at a gas processing facility in order to meet these pipeline specifications. It is common industry practice, however, to blend some unprocessed gas with processed gas to the extent that the combined gas stream is still able to meet the pipeline specifications at the point of injection into the long-haul pipeline.

Although it is typically profitable for producers to separate NGLs from their natural gas streams, there can be periods of time in which the relative value of NGL market prices to natural gas market prices may result in negative processing margins and, as a result, lack of profit from NGL extraction. Because of this margin risk, producers are often willing to pay for the right to bypass the gas processing facility if the circumstances permit. Owners of gas processing facilities may often allow producers to bypass their facilities if they are paid a bypass fee. The bypass fee helps to compensate the gas processing facility for the loss of processing volumes. Under Discovery s contracts that include a bypass option, Discovery s customers may exercise their option to bypass the gas processing plant. Producers with these contracts notify Discovery of their decision to bypass prior to the beginning of each month.

By providing flexibility to both producers and gas processors, bypass options can enhance both parties profitability. Discovery manages its operations given its contract portfolio, which contains a proportion of contracts with this option that is appropriate given current and expected future commodity market conditions.

Competition

The Discovery pipeline system competes with other wellhead to market delivery options available to offshore producers in the Gulf of Mexico. While Discovery offers integrated gathering, transportation, processing and fractionation services through a single provider, it generally competes with other offshore Gulf of Mexico gathering systems and interconnecting gas processing and fractionation facilities, some of which may have the same owner. On the continental shelf in shallow water, Discovery s pipeline system competes primarily with the MantaRay/Nautilus system, the Trunkline system, the Tennessee System and the Venice Gathering System. These competing shallow water gathering systems connect to the following gas processing and fractionation facilities: the MantaRay/Nautilus System connects to the Neptune gas processing plant, the Trunkline pipeline connects to the Patterson and Calumet gas processing plants, the Tennessee pipeline connects to the Yscloskey gas processing plant, and the Venice Gathering System connects to the Venice gas processing plant. In the deepwater region of the Gulf of Mexico, the Discovery pipeline system competes primarily with the Enterprise pipeline and the Cleopatra pipeline. The Enterprise pipeline connects to the ANR/Pelican gas processing plant near Patterson, Louisiana, and the Cleopatra pipeline connects to the Neptune plant in Centerville, Louisiana.

Gas Supply

Approximately 60 offshore production blocks are currently dedicated to the Discovery system. Recently connected blocks include Murphy s Front Runner discovery, Energy Partners Rock Creek discovery, Apache s Tarantula discovery and ATP s Gomez discovery. Additionally, Discovery has signed definitive agreements with Chevron, Total and Statoil to construct an approximate 35-mile gathering pipeline lateral to connect Discovery s existing pipeline system to these producers production facilities for the Tahiti prospect described above. Furthermore, in areas that we believe are accessible to the Discovery pipeline system, approximately 600 deepwater blocks are currently leased and approximately 100 have related exploration plans filed with the Minerals Management Service of the U.S. Department of the Interior, or the MMS, or are named prospects. A named prospect is an individual lease or group of adjacent leases that are generally considered by a producer to have some economic potential for production.

Third-Party Pipeline Supply

Last year s emergency connections to TETCO and Tennessee Gas Pipeline (TGP) have continued to flow gas throughout 2006. Discovery signed a one-year processing contract with TETCO, effective October 2006, for a minimum volume of 100 BBtu/d and a maximum of 300 BBtu/d while the Venice gas plant is being rebuilt. Additionally, Discovery is competing for additional gas throughput from TETCO and TGP.

Carbonate Trend Pipeline General

Our Carbonate Trend gathering pipeline is a sour gas gathering pipeline consisting of approximately 34 miles of 12-inch diameter pipe that is used to gather sour gas production from the Carbonate Trend area off the coast of Alabama. 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. Sour gas is natural gas that has relatively high concentrations of acidic gases such as hydrogen sulfide and carbon dioxide. Our pipeline is designed to transport gas with a hydrogen sulfide and carbon dioxide content that exceeds normal gas transportation specifications. The pipeline was built and placed in service in 2000 and has a maximum design throughput capacity of approximately 120 MMcf/d. For the year ended December 31, 2006, our average transportation volume was approximately 29 MMcf/d.

Gas is shipped through our pipeline to Shell s offshore sour gas gathering pipeline and Yellowhammer sour gas treating facility located onshore in Coden, Alabama. From the Yellowhammer facility, treated gas can be delivered to the Williams-owned Mobile Bay gas processing plant, which has multiple pipeline interconnections to Transco, Florida Gas Transmission, Gulfstream, Mobile Gas Services and GulfSouth pipelines. Treated gas may also be delivered directly into the GulfSouth or the Transco pipelines at the tailgate of the Yellowhammer facility without processing.

Our pipeline extends from Chevron s production platform located at Viosca Knoll Block 251 to an interconnection point with Shell s offshore sour gas gathering facility located at Mobile Bay Block 113. The pipeline is operated by Chevron under an operating agreement. We contract with Williams for the formulation of a corrosion control program to ensure the maintenance and reliability of our pipeline. Due to the corrosive nature of the sour gas, Williams has formulated and Chevron has implemented a corrosion control program for the Carbonate Trend pipeline. Please read Safety and Maintenance.

Revenue from the Carbonate Trend pipeline is generated through negotiated fees that we charge our customers to transport gas to the Shell offshore sour gas gathering system. These fees typically depend on the volume of gas we transport.

Carbonate Trend Customers and Contracts

Customers. Our primary customer on the Carbonate Trend pipeline is Chevron, which, together with Coldren Resources L.P. (Coldren), who purchased Noble Energy s interest, have large lease positions in the Carbonate Trend area. Chevron and Coldren own an interest in more than seven federal leases in the Carbonate Trend area and Chevron is the operator for the majority of these leases. For the year ended December 31, 2006, volumes from these Chevron leases represented approximately 70% of Carbonate Trend s total throughput and 77% of Carbonate Trend s total revenue with volumes from Coldren constituting the remainder.

Contracts. We have long-term transportation agreements with Chevron and Coldren. Pursuant to these agreements, Chevron and Coldren have agreed to transport on our pipeline all gas produced on their seven Carbonate Trend leases for the life of the leases or the economic life of the underlying reserves. There is no minimum volume requirement, and if the leases held by Chevron and Coldren expire or the underlying reserves are depleted, Chevron and Coldren will not be committed to ship any natural gas on our pipeline. In addition, if any lease expires, and is reacquired by the same company within ten years of such expiration, all production from that lease must again be transported via our pipeline. Under these agreements Chevron and Coldren may make an annual election to utilize capacity along a segment of Transco. When Chevron or Coldren utilize this capacity, our per-unit gathering fee is determined by subtracting the FERC tariff-based rate charged by Transco for this capacity from the total negotiated fee. If these customers elect not to utilize the capacity along this segment of Transco, we can make no assurance that this capacity will be made available to these customers in the future. We have the option to terminate these agreements if expenses exceed certain levels or if revenues fall below certain levels and we are not compensated for these expenses or shortfalls.

Competition

Other than the producer gathering lines that connect to the Carbonate Trend pipeline, there are no other sour gas gathering and transportation pipelines in the Carbonate Trend area, and we know of no current plans to build competing pipelines. As a result, as other blocks in the Carbonate Trend are developed, we believe that producers will find it more cost effective to connect to our pipeline than to construct or commission new sour gas pipelines of their own.

Gas Supply

Chevron developed the Viosca Knoll Carbonate Trend area in the shallow waters of the Mobile and Viosca Knoll areas in the eastern Gulf of Mexico. Chevron has filed several exploration plans with the MMS that we believe could result in the discovery of additional amounts of natural gas. Other producers may also transport gas on the Carbonate Trend pipeline.

NGL Services

Our NGL Services segment is comprised of our Conway, Kansas businesses which consist of:

- three integrated NGL storage facilities; and
- a 50% interest in an NGL fractionator.

Our Conway 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 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.

Our Conway storage facilities interconnect directly with two end-use interstate NGL pipelines: MAPL and the Kinder Morgan pipeline. We also, through connections of less than a mile, indirectly interconnect to two additional end-use interstate NGL pipelines: the Valero pipeline and 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 West. The Conway West facility located adjacent to the Conway fractionation facility in McPherson County, Kansas is our primary storage facility. This facility has an aggregate storage capacity of approximately ten million barrels.

Conway East. The Conway East facility is located approximately four miles east of the Conway West facility in McPherson County, Kansas. The Conway East facility has an aggregate storage capacity of approximately five million barrels. The Conway East facility also has an active truck loading and unloading facility, each with two spots, and a rail loading and unloading facility with 20 spots.

Mitchell. The Mitchell facility is located approximately 14 miles west of the Conway West facility in Rice County, Kansas and has an aggregate storage capacity of approximately five million barrels.

Competition

We compete with other salt cavern storage facilities. Our most direct competitor is a ONEOK-owned Bushton, Kansas storage facility that is directly connected to a Kinder Morgan pipeline. Other competitors include a ONEOK-owned facility in Conway, Kansas, a NCRA-owned facility in Conway, Kansas, a ONEOK-owned facility in Hutchinson, Kansas and an Enterprise Products Partners-owned facility in Hutchinson, Kansas. We also compete with storage facilities on the Gulf Coast and in Canada to the extent that NGL product commodity prices differ between the Mid-Continent region and those areas and with interstate pipelines to the extent that they offer storage services.

An increase in competition in the market could arise from new ventures or expanded operations from existing competitors. Other competitive factors include (1) the quantity, location and physical flow characteristics of interconnected pipelines, (2) the ability to offer service from multiple storage locations, (3) the costs of service and rates of our competitors and (4) NGL product commodity prices in the Mid-Continent region as compared to prices in other regions.

NGL Sources and Transportation Options

We generally receive the NGLs that we inject into our facilities, and our customers generally choose to transport the NGLs that we withdraw from our facilities, through the interstate NGL pipelines that interconnect with our storage facilities, including MAPL, a Kinder Morgan pipeline, a Valero pipeline and a ONEOK pipeline. We also receive substantially all of the separated NGLs from our fractionator for storage and further transportation through these interstate pipelines.

Additionally, our customers have the option to have NGLs delivered to or transported from our storage facility, through our active truck loading and unloading facility or our rail loading and unloading facility.

Operating Supply Management

We also generate revenues by managing product imbalances at our Conway facilities. In response to market conditions, we actively manage the fractionation process to optimize the resulting mix of products. Generally, this process leaves us with a surplus of propane volumes and a deficit of ethane volumes. We sell the surplus propane and make up the ethane deficit through open-market purchases and forward purchase and sales contracts. We refer to these transactions as product sales and product purchases. In addition, product imbalances may arise due to measurement variances that occur during the routine operation of a storage cavern. These imbalances are realized when storage caverns are emptied. We are able to sell any excess product volumes for our own account, but must make up product deficits. The flexibility we enjoy as operator of the storage facility allows us to manage the economic impact of deficit volumes by settling deficit volumes either from our storage inventory or through opportunistic open-market purchases.

Historically, we completed these product sales and purchases with third parties. However, in December of 2004, we began to complete these purchases and sales with a subsidiary of Williams. If this arrangement with the Williams subsidiary were terminated, we believe we could once again transact with third parties.

The 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 BP Wattenberg 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.

We own a 50% undivided interest in the Conway fractionation facility, representing capacity of approximately 53,500 bpd. ConocoPhillips owns a 40% undivided interest, representing capacity of approximately 42,800 bpd, and ONEOK owns a 10% undivided interest, representing capacity of approximately 10,700 bpd. 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.

We primarily fractionate NGLs for third party customers for a fee based on the volumes of mixed NGLs fractionated. The per-unit fee we charge is generally subject to adjustment for changes in certain fractionation expenses, including natural gas, electricity and labor costs, which are the principal variable costs in NGL fractionation. As a result, we are generally able to pass through increases in those fractionation expenses to our customers. However, under one of our long-term fractionation contracts described below, there is a cap on the per-unit fee and, under current natural gas market conditions, we are not able to pass through the full amount of increases in variable expenses to this customer. In order to mitigate the fuel price risk with respect to our purchases of natural gas needed to perform under this contract, upon the closing of our initial public offering, Williams transferred to us a contract for the purchase of a sufficient quantity of natural gas from a wholly owned subsidiary of Williams at a price not to exceed a specified price to satisfy our fuel requirements under this fractionation contract.

The results of operations of the Conway fractionation facility are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. Overall, the NGL fractionation business exhibits little to no seasonal variation as NGL production is relatively constant throughout the year. We have capacity available at our fractionation facility to accommodate additional volumes.

Competition

Although competition for NGL fractionation services is primarily based on the fractionation fee, the ability of an NGL fractionator to obtain mixed NGLs and distribute NGL products are also important competitive factors and are determined by the existence of the necessary pipeline and storage infrastructure. NGL fractionators connected to extensive storage, transportation and distribution systems such as ours have direct access to larger markets than those with less extensive connections. Our principal competitors are a ONEOK-owned fractionator located in Medford, Oklahoma, a ONEOK-owned fractionator located in Hutchinson, Kansas and a ONEOK-owned fractionator located in Bushton, Kansas. We compete with the two other joint owners of the Conway fractionation facility for third party customers. We also compete with fractionation facilities on the Gulf Coast, to the extent that NGL product commodity prices differ between the Mid-Continent region and the Gulf Coast.

An increase in competition in the market could arise from new ventures or expanded operations from existing competitors. Other competitive factors include (1) the quantity and location of interconnected pipelines, (2) the costs and rates of our competitors, (3) whether fractionation providers offer to purchase a customers mixed NGLs instead of providing fee based fractionation services and (4) NGL product commodity prices in the Mid-Continent region as compared to prices in other regions.

Mixed NGL Sources

Based on Energy Information Administration projections of relatively stable production levels of natural gas in the Mid-Continent region over the next ten years, we believe that sufficient volumes of mixed NGLs will be available for fractionation in the foreseeable future. In addition, through connections with MAPL and the BP Wattenberg pipeline, the Conway fractionation facility has access to mixed NGLs from additional major supply basins in North America, including additional major supply basins in the Rocky Mountain production area.

NGL Transportation Options

After the mixed NGLs are separated at the fractionator, the NGL products are typically transported to our storage facilities. At our storage facilities, the NGLs may be stored or transported on one of the interconnected NGL pipelines. Our customers also have the option to have their NGL products transported through our truck loading and rail loading facilities. Additionally, when market conditions dictate, we have the ability to place propane directly into MAPL from our fractionator, providing our customers with expedited access to interstate markets.

Customers and Contracts

Customers. Our NGL Services segment customers include NGL producers, NGL pipeline operators, NGL service providers and NGL end-users. Our three largest customers accounted for 37% of our segment revenues in 2006.

Contracts. Our storage year for customer contracts runs from April 1 to March 31. We lease capacity on varying terms from less than six months to a year or more and have additional capacity available to contract. We also have several long-term contracts for terms that expire between 2009 and 2018. Each of these long-term contracts is based on a percentage of our published price of storage in our Conway facilities, which we adjust annually. Our storage revenues are not generally affected by seasonality because our customers generally pay for storage capacity, not injected or withdrawn volumes.

We currently offer our customers four types of storage contracts single product fungible, two product fungible, multi-product fungible and segregated product storage in various quantities and at varying terms. Single product fungible storage allows customers to store a single product. Two-product fungible storage allows customers to store any combination of two fungible products. Multi-product fungible storage allows customers to store any combination of fungible products. In the case of two-product and multi-product storage, the customer designates the quantity of storage space for each product at the beginning of the lease period. Customers may change their quantity configurations throughout the year based upon our ability to accommodate each change. Segregated storage also is available to customers who desire to store non-fungible products at Conway, such as propylene, refinery grade butane and naphtha. We evaluate pricing, volume and availability for segregated storage on a case-by-case basis.

Segregated storage allows a customer to lease an entire storage cavern and have its own product injected and withdrawn without having its product commingled with the products of our other customers. In addition to the fees we charge for fungible product storage and segregated product storage, we also receive fees for overstorage.

One such long-term fractionation contract expires on January 1, 2008. Another long-term fractionation contract expires in 2009. We generally enter into fractionation contracts that cover a portion of our remaining capacity at the Conway facility for periods of one year or less.

Safety and Maintenance

Discovery s natural gas pipeline system is subject to regulation by the United States Department of Transportation, referred to as DOT, under the Accountable Pipeline and Safety Partnership Act of 1996, referred to as the Hazardous Liquid Pipeline Safety Act, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management. The Hazardous Liquid Pipeline

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Safety Act covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations.

Discovery s gas pipeline system is also subject to the Natural Gas Pipeline Safety Act of 1968 and the Pipeline Safety Improvement Act of 2002. 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 high-consequence areas within ten years. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that will require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. We currently estimate we will incur costs of approximately $0.8 million between 2007 and 2008 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 any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program.

States are largely preempted by federal law from regulating pipeline safety but may 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.

Our natural gas pipelines have continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements. In compliance with applicable permit requirements, we completed a survey of portions of our Carbonate Trend pipeline. As a result of this survey, we have determined that it will be necessary to undertake certain restoration activities to repair the partial erosion of the pipeline overburden caused by Hurricane Ivan in September 2004 and Hurricane Katrina in August 2005. We estimate that these restoration activities could be completed by the end of 2007. During these repairs, the pipeline would be shutdown for approximately 40 days, which would decrease our cash flows from operations by approximately $0.3 million. We would fund these repairs with cash flows from operations and seek reimbursement from our insurance carrier and/or contractual counterparties. Additionally, in the omnibus agreement, Williams agreed to reimburse us for the cost of the restoration activities related to Hurricane Ivan to the extent that we are not reimbursed by our insurance carrier and subject to an overall limitation of $14.0 million for all indemnified environmental and related expenditures generally for a period of three years that ends in August 2008. We are assessing our options for meeting our obligations with respect to these restoration activities.

Our Carbonate Trend pipeline requires a corrosion control program to protect the integrity of the pipeline and prolong its life. The corrosion control program consists of continuous monitoring and injection of corrosion inhibitor into the pipeline, periodic chemical treatments and annual detailed comprehensive inspections. We believe that this is an aggressive and proactive corrosion control program that will reduce metal loss, limit corrosion and possibly extend the service life of the pipe by 15 to 20 years.

In addition, we are subject to a number of federal and state laws and regulations, including 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, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the 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 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

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chemicals. These regulations 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. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with the OSHA regulations.

FERC Regulation

Discovery

The Discovery 105-mile mainline, approximately 60 miles of laterals and its market expansion project are subject to regulation by the FERC, under the Natural Gas Act. The Natural Gas Act requires, among other things, that the rates be just and reasonable and nondiscriminatory. Under the Natural Gas Act, the FERC has authority over the construction, operation and expansion of interstate pipeline facilities, as well as the rates, terms and conditions of service provided by the operator of such facilities. In general, Discovery must receive prior FERC approval to construct, operate or expand its FERC-regulated facilities, to initiate new service using such facilities, to alter the terms and conditions of service provided on such facilities, and to abandon service provided by its FERC-regulated facilities. With respect to certain types of construction activities and certain types of service, the FERC has issued rules that allow regulated pipelines to obtain blanket authorizations that obviate the need for prior specific FERC approvals for initiating and abandoning service. Commencing in 1992, the FERC issued a series of orders (Order No. 636), which require interstate pipelines to provide transportation service separate or unbundled from the pipelines sales of gas. Order No. 636 also required interstate pipelines, such as Discovery to provide open access transportation on a non-discriminatory basis that is equal for all similarly situated shippers. The Natural Gas Act also gives the FERC the authority to regulate the rates that Discovery charges for service on portions of its natural gas pipeline system. The natural gas pipeline industry has historically been heavily regulated by federal and state governments, and we cannot predict what further actions the FERC, state regulators, or federal and state legislators may take in the future.

In 2000, the FERC issued Order No. 637 which, among other things:

- required pipelines to implement imbalance management services;
- restricted the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders; and
- implemented a number of new pipeline reporting requirements.

In addition, the FERC implemented new regulations governing the procedure for obtaining authorization to construct new pipeline facilities and has issued a policy statement, which it largely affirmed in a recent order on rehearing, establishing a presumption in favor of requiring owners of new pipeline facilities to charge rates based solely on the costs associated with such new pipeline facilities. We cannot predict what further action the FERC will take on these matters. However, we do not believe that Discovery will be affected by any action taken previously or in the future on these matters materially differently than other natural gas gatherers and processors with which it competes.

Commencing in 2003, the FERC issued a series of orders adopting rules for new Standards of Conduct for Transmission Providers (Order No. 2004) which apply to interstate natural gas pipelines such as Discovery. Order No. 2004 became effective in 2004. Among other matters, Order No. 2004 requires interstate pipelines to operate independently from their energy affiliates, prohibits interstate pipelines from providing non-public transportation or shipper information to their energy affiliates; prohibits interstate pipelines from favoring their energy affiliates in providing service; and obligates interstate pipelines to post on their websites a number of items of information concerning the pipeline, including its organizational structure, facilities shared with energy affiliates, discounts given for transportation service, and instances in which the pipeline has agreed to waive discretionary terms of its tariff. Discovery requested and received a partial waiver from certain portions of Order No. 2004. Since the effective date of Order No. 2004, Discovery has determined that additional waivers from compliance with Order No. 2004 are necessary to accommodate the management committee structure under which Discovery operates. Discovery filed for additional limited waivers from Order No. 2004 compliance on May 6, 2005 requesting a limited waiver to permit three DCP employees to be shared between Discovery and DCP and to provide information necessary for DCP to carry out its responsibilities as an owner of Discovery. The FERC has not yet acted on this filing. However, on November 17, 2006, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded Order No. 2004 as applied to interstate natural gas pipelines and their affiliates. On January 9, 2007, the FERC issued an interim rule. The Interim Rule re-promulgates, on an interim basis, the standards of conduct that were not challenged before the Court. The Interim Rule applies to the relationship between interstate natural gas pipelines and their marketing and brokering affiliates, but not necessarily to their other affiliates, such as gatherers, processors or exploration and production companies. On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking to propose permanent regulations regarding the standards of conduct. A comment period will ensue through April 4, 2007, after which the FERC may enact a final rule. At this stage, it cannot be determined how a final rule may or may not affect Discovery.

Under Discovery s current FERC-approved tariff, the maximum rate that Discovery may charge its customers for the transportation of natural gas along its mainline is $0.1569/MMBtu. This maximum rate is scheduled to decrease in January 2008 to $0.08/MMBtu. At that time, Discovery may be required to reduce the mainline transportation portion of the rate on any of its contracts that have rates above the new maximum rate. This could reduce the revenues generated by Discovery. Discovery may elect to file a rate case with the FERC seeking to alter this scheduled reduction. However, if filed, a rate case may not be successful in even partially preventing the scheduled rate reduction.

In connection with a rate case filed by Discovery, all aspects of its cost of service and rate design of its rates could be reviewed, including the following:

- the overall cost of service, including operating costs and overhead;
- the allocation of overhead and other administrative and general expenses to the rate;
- the appropriate capital structure to be utilized in calculating rates;
- the appropriate rate of return on equity;
- the cost of debt;
- the rate base, including the proper starting rate base;
- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

In a decision issued in July 2004 involving an oil pipeline limited partnership, *BP West Coast Products, LLC v. FERC*, the United States Court of Appeals for the District of Columbia Circuit upheld, among other things, the FERC s determination that certain rates of an interstate petroleum products pipeline, SFPP, L.P., or SFPP, were grandfathered rates under the Energy Policy Act of 1992 and that SFPP s shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC s decision applying the *Lakehead* policy. In its *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In May and June 2005, the FERC issued a statement of general policy, as well as an order on remand of

BP West Coast, respectively, in which it stated it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case by case review requirement. In December 2005, the FERC issued its first case-specific oil pipeline review of the income tax allowance issue in the SFPP

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proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary to determine its income allowance. The FERC s *BP West Coast* remand decision and the new tax allowance policy have been appealed to the D.C. Circuit, and rehearing requests have been filed with respect to the December 2005 order. Therefore, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC s treatment of income tax allowances in cost of service. If the FERC were to disallow a substantial portion of Discovery s income tax allowance, it may be more difficult for Discovery to justify its rates.

These aspects of Discovery s rates also could be reviewed if the FERC or a shipper initiated a complaint proceeding. However, we do not believe that it is likely that a current shipper will challenge Discovery s rates that would materially affect its revenues or cash flows.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been heavily regulated.

Other

The Carbonate Trend pipeline and the Four Corners system are gathering pipelines, and are not subject to the FERC s jurisdiction under the Natural Gas Act.

The primary function of Discovery s natural gas processing plant is the extraction of NGLs and the conditioning of natural gas for marketing into the natural gas pipeline grid. The FERC has traditionally maintained that a processing plant that primarily extracts NGLs is not a facility for transportation or sale of natural gas for resale in interstate commerce and therefore is not subject to its jurisdiction under the Natural Gas Act. We believe that the natural gas processing plant is primarily involved in removing NGLs and, therefore, is exempt from the jurisdiction of the FERC.

The Carbonate Trend sour gas gathering pipeline and the offshore portion of Discovery s natural gas pipeline are subject to regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico.

Environmental Regulation

General

Our operation of pipelines, plants and other facilities for gathering, transporting, processing and treating or storing natural gas, NGLs and other products is subject to stringent and complex federal, state, and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment. Due to the myriad of complex federal, state and local laws and regulations that may affect us, directly or indirectly, you should not rely on the following discussion of certain laws and regulations as an exhaustive review of all regulatory considerations affecting our operations.

As with the industry generally, compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position in that the operations of our competitors are similarly affected. We believe that our operations are in material compliance with applicable environmental laws and regulations. However, these laws and regulations are subject to frequent, and often times more stringent, change by regulatory authorities and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. Violation of environmental laws, regulations and permits can result in the imposition of significant administrative, civil and criminal penalties, remedial obligations, injunctions and construction bans or delays. A discharge of hydrocarbons or hazardous substances into the environment could, to the extent the event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and claims made by neighboring landowners and other third parties for personal injury and property damage.

We or the entities in which we own an interest inspect the pipelines regularly using equipment rented from third party suppliers. Third parties also assist us in interpreting the results of the inspections.

In the omnibus agreement executed in connection with our IPO, Williams agreed to indemnify us in an aggregate amount not to exceed $14.0 million, including any amounts recoverable under our insurance policy covering remediation costs and unknown claims at Conway, generally for three years after the closing of our initial public offering in August 2005, for certain environmental noncompliance and remediation liabilities associated with the assets transferred to us and occurring or existing before the closing date of our initial public offering.

Air Emissions

Our operations are subject to the Clean Air Act and comparable state and local statutes. Amendments to the Clean Air Act enacted in late 1990 require or will require most industrial operations in the United States to incur capital expenditures in order to meet air emission control standards developed by the U.S. Environmental Protection Agency, or EPA, and state environmental agencies. As a result of these amendments, our facilities that emit volatile organic compounds or nitrogen oxides are subject to increasingly stringent regulations, including requirements that some sources install maximum or reasonably available control technology. In addition, the 1990 Clean Air Act Amendments established a new operating permit for major sources. Although we can give no assurances, we believe that the expenditures needed for us to comply with the 1990 Clean Air Act Amendments will not have a material adverse effect on our financial condition or results of operations.

Hazardous Substances and Waste

To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water, and include measures to control pollution of the environment. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste. They 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, the Comprehensive Environmental Response, Compensation, and Liability Act, referred to as CERCLA or the Superfund law and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that 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. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been 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 instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the petroleum exclusion of CERCLA Section 101(14) that currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, 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.

We also generate solid wastes, including hazardous wastes that are subject to the requirements of the federal Solid Waste Disposal Act, the federal Resource Conservation and Recovery Act, referred to as RCRA, and comparable state statutes. 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 our operations, will in the future be designated as hazardous wastes and therefore 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 our maintenance capital expenditures and operating expenses.

We currently own or lease, and our predecessor has in the past owned or leased, properties where hydrocarbons are being or have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other 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 these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

We are a participant in certain hydrocarbon removal and groundwater monitoring activities at Four Corners associated with certain well sites in New Mexico. Of nine remaining active sites, product removal is ongoing at seven 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. Four Corners expects the remaining sites will be closed within four to eight years.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act, also referred to as the CWA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state and federal waters. The CWA imposes substantial potential civil and criminal penalties for non-compliance. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The EPA has promulgated regulations that require us to have permits in order to discharge certain storm water run-off. The EPA has entered into agreements with certain states in which we operate whereby the permits are issued and administered by the respective states. These permits may require us to monitor and sample the storm water run-off. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

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. We believe our operations are in substantial compliance with these regulations. Please read Safety and Maintenance.

Kansas Department of Health and Environment Obligations

We currently own and operate underground storage caverns near Conway, Kansas that have been created by solution mining the caverns in the Hutchinson salt formation. These storage caverns are used to store NGLs and other liquid hydrocarbons. These caverns are subject to strict environmental regulation by the Underground Storage Unit within the Bureau of Water, Geology Section of the KDHE under the Underground Hydrocarbon and Natural Gas Storage Program. The current revision of the Underground Hydrocarbon and Natural Gas Storage regulations became effective on April 1, 2003 (temporary) and August 8, 2003 (permanent); these rules regulate the storage of liquefied petroleum gas, hydrocarbons and natural gas in bedded salt for the purpose of protecting public health and safety, property and the environment and regulates the construction, operation and closure of brine ponds associated with our storage caverns. The regulations specify several compliance deadlines including the final permit application for existing hydrocarbon storage wells by April 1, 2006, certain equipment requirements no later than April 1, 2008 and mechanical integrity and casing testing requirements by April 1, 2010. 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 and Natural Gas Storage 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 brine pond per year. The incremental costs of these activities is approximately $5.5 million per year to complete the workovers and approximately $1.2 million per year to install a double liner on a brine pond. 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 are currently installing and implementing a containment and monitoring system to delineate further the scope of and to arrest the continued migration of the chloride plume at the Mitchell facility. Investigation and delineation of chloride impacts is ongoing at the two Conway area facilities 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 other Conway area 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 fugitive NGLs observed in the subsurface at the Conway Underground East facility. In addition, we have also recently detected fugitive 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 releases around the abandoned storage caverns.

We are continuing to 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.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that we own in fee, such as land at the Conway fractionation and storage facility, and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which major facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, right-of-way and licenses. 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.

We are currently in discussions with the Jicarilla Apache Nation regarding rights-of-way that expired at the end of 2006 for a segment of Four Corners gathering system which flows less than 10% of the system s gathered volumes. We continue to operate our assets on these reservation lands pursuant to a three-month agreement while we conduct further discussions that could result in renewal of our rights of way, sale of the gathering assets on reservation land or other options that might be in the mutual interest of both parties.

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Employees

We do not have any employees. We are managed and operated by the directors and officers of our general partner. To carry out our operations our general partner or its affiliates employed approximately 304 people, as of December 31, 2006, who will spend at least a majority of their time operating the Four Corners, Conway and Carbonate Trend facilities and approximately 110 general and administrative full-time equivalent employees in support of these operations. Discovery is operated by Williams pursuant to an operating and maintenance agreement and the employees who operate the Discovery assets are therefore not included in the above numbers. For further information, please read Directors and Executive Officers of the Registrant Reimbursement of Expenses of our General Partner and Certain Relationships and Related Transactions.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

We have no revenue or segment profit/loss attributable to international activities.

Item 1A. *Risk Factors*

FORWARD-LOOKING STATEMENTS/RISK FACTORS AND CAUTIONARY STATEMENT

Certain matters contained in this report include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements discuss our expected future results based on current and pending business operations.

All statements, other than statements of historical facts, included in this report which address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as anticipates, believes, could, may, should, continues, estimates, expects, forecasts, might, planned, potential, projects, expressions. These forward-looking statements include, among others, statements regarding:

- amounts and nature of future capital expenditures;
- expansion and growth of our business and operations;
- business strategy;
- cash flow from operations;
- seasonality of certain business segments; and
- natural gas liquids and gas prices and demand.

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this document. Limited partner interests 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. The reader 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. In that case, we might not be able to pay distributions on our common units and the trading price of our common units could decline and unitholders could lose all or part of their investment. 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 which could cause actual results to differ from those in the forward-looking statements include:

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

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Because of the natural decline in production from existing wells and competitive factors, the success of our gathering and transportation businesses depends on our ability to connect new sources of natural gas supply, which is dependent on factors beyond our control. Any decrease in supplies of natural gas could adversely affect our business and operating results.

Our processing, fractionation and storage businesses could be affected by any decrease in the price of natural gas liquids or a change in the price of natural gas liquids relative to the price of natural gas.

Lower natural gas and oil prices could adversely affect our fractionation and storage businesses.

We depend on certain key customers and producers for a significant portion of our revenues and supply of natural gas and natural gas liquids. The loss of any of these key customers or producers could result in a decline in our revenues and cash available to pay distributions.

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

Our future financial and operating flexibility may be adversely affected by restrictions in our indentures and by our leverage.

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.

Williams revolving credit facility and Williams public indentures contain financial and operating restrictions that may limit our access to credit. In addition, our ability to obtain credit in the future will be affected by Williams credit ratings.

Our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to the detriment of our unitholders.

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

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

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

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

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

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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 include the following:

Risks Inherent in Our Business

We may not have sufficient cash from operations to enable us 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 each quarter 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;
- 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 such as:

- the level of capital expenditures we make;
- the restrictions contained in our and Williams debt agreements 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;
- the amount of cash that Discovery distributes to us; and
- reimbursement payments to us by, and credits from, Williams under the omnibus agreement.

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.

Because of the natural decline in production from existing wells and competitive factors, the success of our gathering and transportation businesses depends on our ability to connect new sources of natural gas supply, which is dependent on factors beyond our control. Any decrease in supplies of natural gas could adversely affect our business and operating results.

Our and Discovery s pipelines receive natural gas directly from offshore producers. Our Four Corners gathering system receives natural gas directly from producers in the San Juan Basin. The production from existing wells connected to these pipelines and our Four Corners gathering system will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. We do not produce an aggregate reserve report on a regular basis or regularly obtain or update independent reserve evaluations. The amount of natural gas reserves underlying these wells may be less than we anticipate, and the rate at which production will decline from these reserves may be greater than we anticipate. Accordingly, to

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maintain or increase throughput levels on these pipelines and the utilization rate of Discovery s natural gas processing plant and fractionator and our Four Corners processing plants and treating plants, we and Discovery must continually connect new supplies of natural gas. The primary factors affecting our ability to connect new supplies of natural gas and attract new customers to our pipelines include: (1) the level of successful drilling activity near these pipelines; (2) our ability to compete for volumes from successful new wells and existing wells connected to third parties; and (3) our and Discovery s ability to successfully complete lateral expansion projects to connect to new wells.

We do not have any current significant lateral expansion projects planned and Discovery has only one currently planned significant lateral expansion project. Discovery signed definitive agreements with Chevron, Shell and Statoil to construct an approximate 35-mile gathering pipeline lateral to connect Discovery s existing pipeline system to these producers production facilities for the Tahiti prospect in the deepwater region of the Gulf of Mexico. Initial production is expected in the first half of 2008.

The level of drilling activity in the fields served by our and Discovery s pipelines and our Four Corners gathering system is dependent on economic and business factors beyond our control. The primary factors that impact drilling decisions are oil and natural gas prices. A sustained decline in oil and natural gas prices could result in a decrease in exploration and development activities in these fields, which would lead to reduced throughput levels on our pipelines and gathering system. Other factors that impact production decisions include producers capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits, the availability of qualified personnel and equipment, the quality of drilling prospects in the area and regulatory changes. Because of these factors, even if new oil or natural gas reserves are discovered in areas served by our pipelines and gathering system, producers may choose not to develop those reserves. If we were not able to connect new supplies of natural gas to replace the natural decline in volumes from existing wells, due to reductions in drilling activity, competition, or difficulties in completing lateral expansion projects to connect to new supplies of natural gas, throughput on our pipelines and gathering system and the utilization rates of Discovery s natural gas processing plant and fractionator and our Four Corners processing plants and treating plants would decline, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Lower natural gas and oil prices could adversely affect our fractionation and storage businesses.

Lower natural gas and oil prices could result in a decline in the production of natural gas and NGLs resulting in reduced throughput on our pipelines and our Four Corners gathering system. Any such decline would reduce the amount of NGLs we fractionate and store, which could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

In general terms, the prices of natural gas, NGLs and other hydrocarbon products fluctuate in response to changes in supply, changes in demand, market uncertainty and a variety of additional factors that are impossible to control. These factors include:

- worldwide economic conditions;
- weather conditions and seasonal trends;
- the levels of domestic production and consumer demand;
- the availability of imported natural gas and NGLs;
- the availability of transportation systems with adequate capacity;

the price and availability of alternative fuels;

the effect of energy conservation measures;

the nature and extent of governmental regulation and taxation; and

the anticipated future prices of natural gas, NGLs and other commodities.

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Our processing, fractionation and storage businesses could be affected by any decrease in NGL prices or a change in NGL prices relative to the price of natural gas.

Lower NGL prices would reduce the revenues we generate from the sale of NGLs for our own account. Under certain gas processing contracts, referred to as percent-of-liquids and keep whole contracts, Discovery and Four Corners both receive NGLs removed from the natural gas stream during processing. Discovery and Four Corners can then choose to either fractionate and sell the NGLs or to sell the NGLs directly. In addition, product optimization at our Conway fractionator generally leaves us with excess propane, an NGL, which we sell. We also sell excess storage volumes resulting from measurement variances at our Conway storage facilities.

The relationship between natural gas prices and NGL prices may also affect our profitability. When natural gas prices are low relative to NGL prices, it is more profitable for Discovery, Four Corners and their 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 of the increased cost (principally that of natural gas as a feedstock and a fuel) of separating the mixed NGLs from the natural gas. As a result, Discovery and Four Corners may experience periods in which higher natural gas prices reduce the volumes of NGLs removed at their processing plants, which would reduce their 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.

We depend on certain key customers and producers for a significant portion of our revenues and supply of natural gas and NGLs. The loss of any of these key customers or producers could result in a decline in our revenues and cash available to pay distributions.

We rely on a limited number of customers for a significant portion of our revenues. Our largest customer for the year ended December 31, 2006, other than a subsidiary of Williams that purchases NGLs, is ConocoPhillips which accounted for approximately 24% of the Gathering and Processing West segment s total revenues, including revenues attributable to Burlington Resources prior to its acquisition by ConocoPhillips on March 31, 2006.

In addition, 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. For example, Four Corners is in active negotiations with several customers to renew gathering, processing and treating contracts that are in evergreen status and that represent approximately 9% of our total revenues for the year ended December 31, 2006. The negotiations may not result in any extended commitments from these customers. The loss of all or even a portion of the volumes of natural gas or NGLs, as applicable, supplied by these customers, as a result of competition 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.

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. For example, MAPL delivers its customers mixed NGLs to our Conway fractionator and provides access to multiple end markets for NGL products of our storage customers. If MAPL were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to pipelines, reduced operating pressures, lack of capacity or other causes, our customers would be unable to store or deliver NGL products and we would be unable to receive deliveries of mixed NGLs at our Conway fractionator. This would have an immediate adverse impact on our ability to enter into short-term storage contracts and our ability to fractionate sufficient volumes of mixed NGLs at Conway.

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MAPL also provides the only liquids pipeline access to multiple end markets for NGL products that are recovered from our Four Corners processing plants. If MAPL were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to pipelines, reduced operating pressures, lack of capacity or other causes, we would be unable to deliver a substantial portion of the NGLs recovered at our Four Corners processing plants. This would have an immediate impact on our ability to sell or deliver NGL products recovered at our Four Corners processing plants. In addition, the five pipeline systems that move natural gas to end markets from the San Juan Basin connect to our Four Corners treating and processing facilities, including the El Paso Natural Gas, Transwestern, Williams Northwest Pipeline, PNM and Southern Trails systems. Some of these natural gas pipeline systems have minimal excess capacity. If any of these pipeline systems were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to pipelines, reduced operating pressures, lack of capacity or other causes, our customers would be unable to deliver natural gas to end markets. This would reduce the volumes of natural gas processed or treated at our Four Corners treating and processing facilities. Either of such events could materially and adversely affect our business results of operations, financial condition and ability to make distributions to unitholders.

Any temporary or permanent interruption in operations at MAPL or any other third party pipelines or facilities that would cause a material reduction in volumes transported on our pipelines or our gathering systems or processed, fractionated, treated or stored at our facilities could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to unitholders.

Williams revolving credit facility and Williams public indentures contain financial and operating restrictions that may limit our access to credit. In addition, our ability to obtain credit in the future will be affected by Williams credit ratings.

We have the ability to incur up to $75.0 million of indebtedness under Williams $1.5 billion revolving credit facility. However, this $75.0 million of borrowing capacity will only be available to us to the extent that sufficient amounts remain unborrowed by Williams and its other subsidiaries. As a result, borrowings by Williams could restrict our access to credit. As of December 31, 2006, letters of credit totaling $29.0 million had been issued on behalf of Williams by the participating institutions under the facility and no revolving credit loans were outstanding. In addition, Williams public indentures contain covenants that restrict Williams and our ability to incur liens to support indebtedness. As a result, if Williams were not in compliance with these covenants, we could be unable to make any borrowings under our $75.0 million borrowing limit, even if capacity were otherwise available. 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 control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, Williams ability to comply with these covenants may be impaired. While we are not individually subject to any financial covenants or ratios under Williams revolving credit facility, Williams and its subsidiaries as a whole are subject to these tests. Accordingly, any breach of these or other covenants, ratios or tests, would terminate our and Williams and its other subsidiaries ability to make additional borrowings under the credit facility and, as a result, could limit our ability to finance our operations, make acquisitions or pay distributions to unitholders. In addition, a breach of these covenants by Williams would cause the acceleration of Williams and, in some cases, our outstanding borrowings under the facility. In the event of acceleration of indebtedness, Williams, the other borrowers or we might not have, or be able to obtain, sufficient funds to make required repayments of the accelerated indebtedness. For more information regarding our debt agreements, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Due to our relationship with Williams, our ability to obtain credit will be affected by Williams credit ratings. Any future down grading of a Williams credit rating would likely also result in a down grading of our credit rating. A down grading of a Williams credit rating could limit our ability to obtain financing in the future upon favorable terms, if at all.

Our future financial and operating flexibility may be adversely affected by restrictions in our indentures and by our leverage.

In June 2006, we issued $150.0 million of senior unsecured notes and in December 2006, we issued an additional $600.0 million of senior unsecured notes, both of which caused our leverage to increase. Our total outstanding long-term debt as of December 31, 2006 was $750.0 million, representing approximately 85% of our total book capitalization.

Our debt service obligations and restrictive covenants in 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 to 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 corporate purposes or other purposes;
- adversely affect our ability to pay cash distributions to unitholders;
- diminish our ability to withstand a 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. 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.

Discovery is not prohibited from incurring indebtedness, which may affect our ability to make distributions to unitholders.

Discovery is not prohibited by the terms of its limited liability company agreement from incurring indebtedness. If Discovery was to incur significant amounts of indebtedness, it may inhibit its ability to make distributions to us. An inability by Discovery to make distributions to us would materially and adversely affect our ability to make distributions to unitholders because we expect distributions we receive from Discovery to represent a significant portion of the cash we distribute to unitholders.

We do not own all of the interests in the Conway fractionator or Discovery, which could adversely affect our ability to operate and control these assets in a manner beneficial to us.

Because we do not wholly own the Conway fractionator or Discovery, we may have limited flexibility to control the operation of, dispose of, encumber or receive cash from these assets. Any future disagreements with the other co-owners of these assets could adversely affect our ability to respond to changing economic or industry conditions, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

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Discovery may reduce its cash distributions to us in some situations.

Discovery s limited liability company agreement provides that Discovery will distribute its available cash to its members on a quarterly basis. Discovery s available cash includes cash on hand less any reserves that may be appropriate for operating its business. As a result, reserves established by Discovery, including those for working capital, will reduce the amount of available cash. The amount of Discovery s quarterly distributions, including the amount of cash reserves not distributed, is determined by the members of its management committee representing a majority-in-interest in such entity.

We own a 40% interest in Discovery and an affiliate of Williams owns a 20% interest in Discovery. In addition, to the extent Discovery requires working capital in excess of applicable reserves, the Williams member must make working capital advances to Discovery of up to the amount of Discovery s two most recent prior quarterly distributions of available cash, but Discovery must repay any such advances before it can make future distributions to its members. As a result, the repayment of advances could reduce the amount of cash distributions we would otherwise receive from Discovery. In addition, if the Williams member cannot advance working capital to Discovery as described above, Discovery s business and financial condition may be adversely affected.

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 operates all of our assets, other than:

- the Carbonate Trend pipeline, which is operated by Chevron;
- our Conway fractionator and storage facilities, which we operate; and
- most of our Four Corners field compression, excluding major turbine compressor stations, which is operated by Hanover.

We have a limited ability to control our operations or the associated costs of these operations. 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 also rely on Williams for 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 as an operator and on Williams outsourcing relationships, our reliance on Chevron, our reliance on Hanover and our limited ability to control certain costs could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Hanover operates our Four Corners field compression pursuant to agreements that are on a month-to-month status and can be terminated by Hanover at any time by providing notice thirty days before the termination. If Hanover terminates the agreements, we would need to find another operator for the field compression. A change in operators could result in a significant interruption of service.

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

We compete with similar enterprises in our respective areas of operation. Some of our competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas and NGLs than we do.

Discovery competes with other natural gas gathering and transportation and processing facilities and other NGL fractionation facilities located in south Louisiana, offshore in the Gulf of Mexico and along the Gulf Coast, including the Manta Ray/Nautilus systems, the Trunkline pipeline and the Venice Gathering System and the processing and fractionation facilities that are connected to these pipelines.

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Our Conway fractionation facility competes for volumes of mixed NGLs with fractionators located in each of Hutchinson, Kansas, Medford, Oklahoma, and Bushton, Kansas owned by ONEOK Partners, L.P., the other joint owners of the Conway fractionation facility and, to a lesser extent, with fractionation facilities on the Gulf Coast. In April 2006, ONEOK, Inc. transferred its entire gathering and processing, natural gas liquids, and pipelines and storage segments to ONEOK Partners, L.P. (formerly known as Northern Border Partners, L.P.), or ONEOK. Our Conway storage facilities compete with ONEOK-owned storage facilities in Bushton, Kansas and in Conway, Kansas, an NCRA-owned facility in Conway, Kansas, a ONEOK-owned facility in Hutchinson, Kansas and an Enterprise Products Partners-owned facility in Hutchinson, Kansas and, to a lesser extent, with storage facilities on the Gulf Coast and in Canada.

Four Corners competes with other natural gas gathering, processing and treating facilities in the San Juan Basin, including Enterprise, Red Cedar and TEPPCO. In addition, our customers who are significant producers of gas or consumers of NGLs may develop their own gathering, processing, fractionation and storage facilities in lieu of using ours.

Also, competitors may establish new connections with pipeline systems that would create additional competition for services we provide to our customers. For example, other than the producer gathering lines that connect to the Carbonate Trend pipeline, there are no other sour gas pipelines near our Carbonate Trend pipeline, but the producers that are currently our customers could construct or commission such pipelines in the future.

Our ability to renew or replace existing contracts with our customers 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, results of operations, financial condition and ability to make cash distributions to unitholders.

Our results of storage and fractionation operations are dependent upon the demand for propane and other NGLs. A substantial decrease in this demand could adversely affect our business and operating results.

Our Conway storage and fractionation operations are impacted by demand for propane more than any other NGLs. Conway, Kansas is one of the two major trading hubs for propane and other NGLs in the continental United States. Demand for propane at Conway is principally driven by demand for its use as a heating fuel. However, propane is also used as an engine and industrial fuel and as a petrochemical feedstock in the production of ethylene and propylene. Demand for propane as a heating fuel is significantly affected by weather conditions and the availability of alternative heating fuels such as natural gas. Weather-related demand is subject to normal seasonal fluctuations, but an unusually warm winter could cause demand for propane as a heating fuel to decline significantly. Demand for other NGLs, which include ethane, butane, isobutane and natural gasoline, could be adversely impacted by general economic conditions, a reduction in demand by customers for plastics and other end products made from NGLs, an increase in competition from petroleum-based products, government regulations or other reasons. Any decline in demand for propane or other NGLs could cause a reduction in demand for our Conway storage and fractionation services.

When prices for the future delivery of propane and other NGLs that we store at our Conway facilities fall below current prices, customers are less likely to store these products, which could reduce our storage revenues. This market condition is commonly referred to as backwardation. When the market for propane and other NGLs is in backwardation, the demand for storage capacity at our Conway facilities may decrease. While this would not impact our long-term capacity leases, customers could become less likely to enter into short-term storage contracts.

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 a number of factors, some of which we can control and some of which we cannot. These factors include our ability to:

- identify businesses engaged in managing, operating or owning pipeline, processing, fractionation and storage assets, or other midstream assets for acquisitions, joint ventures and construction projects;
- control costs associated with acquisitions, joint ventures or construction projects;
- consummate acquisitions or joint ventures and complete construction projects, including Discovery s Tahiti lateral expansion project;
- integrate any acquired or constructed business or assets successfully with our existing operations and into our operating and financial systems and controls;
- hire, train and retain qualified personnel to manage and operate our growing business; and
- obtain required financing for our existing and new operations.

A 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. Furthermore, competition from other buyers could reduce our acquisition opportunities or cause us to pay a higher price than we might otherwise pay. In addition, Williams is not restricted from competing with us. Williams may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

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 could result in the incurrence of indebtedness and additional liabilities and excessive costs that could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders. Further, if we issue additional common units in connection with future acquisitions, unitholders interest in the partnership will be diluted and distributions to unitholders may be reduced.

Discovery s interstate tariff rates are subject to review and possible adjustment by federal regulators, which could have a material adverse effect on our business and operating results. Moreover, because Discovery is a non-corporate entity, it may be disadvantaged in calculating its cost of service for rate-making purposes.

The FERC, pursuant to the Natural Gas Act, regulates Discovery s interstate pipeline transportation service. Under the Natural Gas Act, interstate transportation rates must be just and reasonable and not unduly discriminatory. If the FERC lowers the tariff rates Discovery is permitted to charge its customers, on its own initiative, or as a result of challenges raised by Discovery s customers or third parties, the FERC could require refunds of amounts collected under rates which it finds unlawful. An adverse decision by the FERC in approving Discovery s regulated rates could adversely affect our cash flows. Although the FERC generally does not regulate the natural gas gathering operations of Discovery under the Natural Gas Act, federal regulation influences the parties that gather natural gas on the Discovery gas gathering system.

Discovery s maximum regulated rate for mainline transportation is scheduled to decrease in 2008. At that time, Discovery may be required to reduce its mainline transportation rate on all of its contracts that have rates above the new maximum rate. This could reduce the revenues generated by Discovery. Discovery may elect to file a rate case with the FERC seeking to alter this scheduled maximum rate reduction. However, if filed, a rate case may not be successful in even partially preventing the rate reduction. If Discovery makes

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such a filing, all aspects of Discovery s cost of service and rate design could be reviewed, which could result in additional reductions to its regulated rates.

Pursuant to an order on and remand of a decision by the U.S. Court of Appeals for the District of Columbia Circuit in *BP West Coast Products, LLC v. FERC* and a policy statement regarding income tax allowances issued by the FERC, it will permit pipelines to include in cost-of -service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Both the FERC s income tax allowance policy and its initial application in an individual pipeline rate proceeding are, however, currently being challenged in the court of appeals. As a result, the ultimate outcome of these proceedings is not certain and could result in a reversal of the FERC s policy or other changes to the FERC s treatment of income tax allowances in cost-of -service. Under the FERC s current policy, if Discovery were to file a rate case, as discussed above, it would be required to prove pursuant to the new policy s standard that the inclusion of an income tax allowance in Discovery s cost-of -service was permitted. If the FERC were to disallow a substantial portion of Discovery s income tax allowance, it may be more difficult for Discovery to justify its rates.

On November 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded the FERC s Order No. 2004, which adopted standards of conduct governing interstate pipelines interactions with their energy affiliates. Discovery had previously received certain waivers from compliance with portions of Order No. 2004. It is uncertain what action, if any, the FERC will take in response to the remand. If the FERC issues new standards of conduct, Discovery may incur additional compliance costs.

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

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

- hurricanes, tornadoes, floods, fires, extreme weather conditions and other natural disasters and acts of terrorism;
- damages to pipelines and pipeline blockages;
- leakage of natural gas (including sour gas), NGLs, brine or industrial chemicals;
- collapse of NGL storage caverns;
- operator error;
- pollution;
- fires, explosions and blowouts;
- risks related to truck and rail loading and unloading; and
- risks related to operating in a marine environment.

Any of these or any other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of life, property damage, damage to the environment or other significant exposure to liability. For example, in 2004 we experienced a temporary interruption of service on one of our pipelines due to an influx of seawater while connecting a new lateral. Also, Hurricanes Ivan and Katrina in 2004 and 2005, respectively, eroded part of the overburden covering our Carbonate Trend Pipeline. During the repair, it would be shutdown for approximately 40 days, which would decrease our cash flows from operations by approximately $0.3 million. We expect that the cost of the repair would be recoverable from insurance.

Insurance may be inadequate, and in some instances, we may be unable to obtain insurance on commercially reasonable terms, if at all. A significant disruption in operations or a significant liability for

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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.

The only pipeline that provides NGL transportation capacity in the San Juan Basin has filed at the FERC to increase certain of its tariff rates. If the requested increase is granted, our operating costs would increase, which could have an adverse effect on our business and operating results.

MAPL, the only pipeline in the San Juan Basin that provides NGL transportation capacity, has filed at the FERC to increase certain of its tariff rates. If the FERC grants this request to increase those tariff rates, we estimate that our cost of transporting NGLs to certain markets would increase by approximately $1.5 million per year, which could have an adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Pipeline integrity programs and repairs may impose significant costs and liabilities on us.

In December 2003, the U.S. Department of Transportation issued a final rule requiring pipeline operators to develop integrity management programs for gas transportation pipelines located in high consequence areas where a leak or rupture could do the most harm. The final rule requires operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

The final rule incorporates the requirements of the Pipeline Safety Improvement Act of 2002. The final rule became effective on January 14, 2004. In response to this new Department of Transportation rule, we have initiated pipeline integrity testing programs that are intended to assess pipeline integrity. In addition, we have voluntarily initiated a testing program to assess the integrity of the brine pipelines of our Conway storage facilities and replaced three sections of brine systems at a cost of $0.7 million. We have completed approximately one-third of the testing and expect to complete the remainder of the testing in 2007 and 2008. The results of these testing programs will be analyzed, and could cause us to incur significant capital and operating expenditures in response to any repair, remediation, preventative or mitigating actions that are determined to be necessary.

Additionally, the transportation of sour gas in our Carbonate Trend pipeline necessitates a corrosion control program in order to protect the integrity of the pipeline and prolong its life. Our corrosion control program may not be successful and the sour gas could compromise pipeline integrity. Our inability to reduce corrosion on our Carbonate Trend pipeline to acceptable levels could significantly reduce the service life of the pipeline and could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

The State of New Mexico recently enacted rule changes that permit the pressure in gathering pipelines to be reduced below atmospheric levels. In response to these rule changes, Four Corners may reduce the pressures in its gathering lines below atmospheric levels. With Four Corners concurrence, producers may also reduce pressures below atmospheric levels prior to delivery to Four Corners. All of the gathering lines owned by Four Corners in the San Juan

Basin are made of steel. Reduced pressures below atmospheric levels may introduce increasing amounts of oxygen into those pipelines, which could cause an acceleration of the corrosion.

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, and we are therefore 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. For example, portions of our Four Corners gathering system are located on Native American rights-of-way. Four Corners is currently in discussions with the Jicarilla Apache Nation regarding rights-of-way that expired at the end of 2006 for a segment of the gathering system which flows less than 10% of Four Corners gathered volumes.

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.

The risk of substantial environmental costs and liabilities is inherent in natural gas gathering, transportation and processing, 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 stringent federal, state and local laws and regulations relating to protection of the public and the environment. These laws include, for example:

- the Federal Clean Air Act and analogous state laws, which impose obligations related to air emissions;
- the Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act, or CWA, and analogous state laws, which regulate discharge of wastewaters from our facilities to state and federal waters;
- the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the Superfund law, and analogous state laws that 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
- the federal Resource Conservation and Recovery Act, also known as RCRA, and analogous state laws that 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, or EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Joint and several, strict liability may be incurred without regard to fault under CERCLA, RCRA and analogous state laws for the remediation of contaminated areas.

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. Private parties, including the owners of properties through which our pipeline and gathering systems pass, 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.

For example, the KDHE, regulates the storage of NGLs and natural gas in the state of Kansas. This agency also regulates the construction, operation and closure of brine ponds associated with such storage facilities. In response to a significant incident at a third party facility, the KDHE promulgated more stringent regulations regarding safety and integrity of brine ponds and storage caverns. Additionally, incidents similar to the incident at a third party facility that prompted the recent KDHE regulations could prompt the issuance of even stricter regulations.

There is increasing pressure in New Mexico from environmental groups and area residents to reduce the noise from midstream operations through regulatory means. If these groups are successful, we may have to make capital expenditures to muffle noise from our facilities or to ensure adequate barriers or distance to mitigate noise concerns.

Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage in the event 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, new environmental regulations might adversely affect our products and activities, including processing, fractionation, storage and transportation, as well as waste management and air emissions. Federal and state agencies also could impose additional safety requirements, any of which could affect our profitability.

The natural gas gathering operations in the San Juan Basin may be subjected to regulation by the state of New Mexico, which could negatively affect our revenues and cash flows.

The New Mexico state legislature has previously called for hearings to take place to examine the regulation of natural gas gathering systems in the state. It is unclear if further discussions or hearings will occur, but they could result in gathering regulation that would affect the fees that we could collect for gathering services. This type of regulation could adversely impact our revenues and cash flow.

Risks Inherent in an Investment in Us

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 outstanding notes 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. Williams Partners L.P. has no significant assets other than the ownership interests in its subsidiaries. As a result, our ability to make required payments on our outstanding notes 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 outstanding notes, or to repurchase our outstanding notes 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 outstanding notes or borrowing funds to make distributions on our common units. We cannot assure our notes holders that we would be able to refinance our outstanding notes or that we will be able to borrow funds to make distributions on our common units.

Common units held by Williams eligible for future sale may have adverse effects on the price of our common units.

As of December 31, 2006, Williams held 1,250,000 common units and 7,000,000 subordinated units, representing a 21% limited partnership interest in us. Williams may, from time to time, sell all or a portion of its common units or subordinated units. Sales of substantial amounts of their common units or subordinated 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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If we fail to obtain the approval of the unitholders for the conversion of the Class B units to common units, the minimum quarterly distribution payable in respect of the Class B units will increase, which will reduce the amount of cash available for distribution on our common units.

If conversion of our Class B units is not approved by our unitholders within six months of the closing of the issuance of the Class B units, which is June 11, 2007, the holders of the Class B units will be entitled to receive an increased quarterly distribution equal to 115% of the quarterly distribution and distributions on liquidation payable on each common unit, but in each case the holders of the Class B units will remain subordinated to the holders of common units with respect to quarterly distributions and any arrearages thereon. Based on our current quarterly distribution of $0.47 per unit, this increase would result in an aggregate of approximately $0.5 million of additional quarterly distributions on Class B units. If we become obligated to pay an increased quarterly distribution on the Class B units, our cash on hand will be reduced and we may not have sufficient cash available to pay distributions on our common units.

Potential changes in accounting standards might cause us to revise our financial results and disclosures in the future.

Recently-discovered accounting irregularities in various industries have forced regulators and legislators to take a renewed look at accounting practices, financial disclosure, the relationships between companies and their independent auditors, 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 or the SEC could enact new accounting standards 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, financial condition and ability to make cash distributions to unitholders.

Terrorist attacks have resulted in increased costs, and attacks directed at our facilities or those of our suppliers and customers could disrupt our operations.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11 attacks, the United States government has issued warnings that energy assets may be the future target of terrorist organizations. These developments have subjected our operations to increased risks and costs. The long-term impact that terrorist attacks and the threat of terrorist attacks may have on our industry in general, and on us in particular, is not known at this time. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways. In addition, uncertainty regarding future attacks and war cause global energy markets to become more volatile. Any terrorist attack on our facilities or those of our suppliers or customers could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Changes in the insurance markets attributable to terrorists attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in financial markets as a result of terrorism or war could also affect our ability to raise capital.

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. Our credit procedures and policies may not be adequate to fully eliminate customer credit risk. 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 have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

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Our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to the detriment of our unitholders.

Williams owns the 2% general partner interest and a 21% limited partner interest in us and owns and controls our 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 executive officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, Williams. Conflicts of interest may arise between our general partner and its affiliates, 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 situations:

- neither our partnership agreement nor any other agreement requires Williams or its affiliates to pursue a business strategy that favors us;

- our general partner is allowed to take into account the interests of parties other than us, such as Williams, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;

- Williams and its affiliates may engage in competition with us;

- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- 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, as well as whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not, which determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units;

- 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 a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;

- 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;

- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% 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.

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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. 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;

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;

provides that 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, and that, 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; and

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 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.

By purchasing a common unit, a common unitholder will be bound by the provisions in the partnership agreement, including the provisions discussed above.

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 662/3% of all outstanding common and subordinated units voting together as a single class is required to remove our general partner. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically be converted into common units and any existing arrearages on the common units will be extinguished. A removal of our general partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests.

Cause is narrowly defined in our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of

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charges of poor management of the business, so the removal of our general partner because of the unitholders dissatisfaction with our general partner s performance in managing our partnership will most likely result in the termination of the subordination period.

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 does not restrict the ability of the members of our general partner from transferring their member interest in our general partner to a third party. The new members of our general partner would then be in a position to replace the board of directors and officers of the general partner with their own choices and to control the decisions taken by the board of directors and officers of the general partner. In addition, pursuant to the omnibus agreement with Williams, any new owner of the general partner would be required to change our name so that there would be no further reference to Williams.

Increases in interest rates may cause the market price of our common units to decline.

An increase in interest rates may cause a corresponding decline in demand for equity investments in general, and in particular for yield-based equity investments such as our common units. Any such increase in interest rates or reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

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

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units subject to the limitations imposed by the New York Stock Exchange. 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;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Williams and its affiliates may compete directly with us and have no obligation to present business opportunities to us.

The omnibus agreement does not prohibit Williams and its affiliates from owning assets or engaging in businesses that compete directly or indirectly 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 any of those assets. In addition, under our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to Williams and its affiliates. As a result, neither Williams nor any of its affiliates has any obligation to present business opportunities to us.

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, which it may assign to any of its affiliates or to us, 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. 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 vote on any matter. The partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

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

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf, which will be determined by our general partner. These expenses will include all costs incurred by the general partner and its affiliates in managing and operating us, including costs for rendering corporate staff and support services to us. Please read Certain Relationships and Related Transactions. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates could adversely affect our ability to pay cash distributions to unitholders.

Unitholders may not have limited liability if a court finds that unitholder action constitutes control of our business. Unitholders may also have liability to repay distributions.

As a limited partner in a partnership organized under Delaware law, unitholders could be held liable for our obligations to the same extent as a general partner if they participate in the control of our business. Our general partner generally has unlimited liability for the obligations of the partnership, such as its debts and environmental liabilities, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution. 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.

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 entity-level taxation by states. If the IRS were to treat us as a corporation or if we were to become subject to entity-level taxation for state tax purposes, then our cash available to pay distributions to unitholders would be substantially reduced.

The anticipated after-tax 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 matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%. 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. For example, because of widespread state budget deficits, 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 to pay 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.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contest will be borne by 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. 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 positions we take. Any contest with the IRS may materially and adversely impact the market for our 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 may be required to pay taxes on their share of our income even if unitholders do not receive any cash distributions from us.

Unitholders are 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 our common units could be different than expected.

If a unitholder sell 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 it was allocated 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, whether or not representing gain, may be ordinary income to the unitholder.

Tax-exempt entities and foreign 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), regulated investment companies (known as mutual funds), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them.

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 units as having the same tax benefits without regard to the 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 will all aspects of existing Treasury regulations. 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 our 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. 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. We own property and conduct business in Kansas, Louisiana, Colorado and New Mexico. We may own property or conduct business in other states or foreign countries in the future. 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.

The sale or exchange of 50% or more of our capital and profits interests will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated 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 and could result in a deferral of depreciation deductions allowable in computing our taxable income.

Item 1B. *Unresolved Staff Comments*

None.

Item 3. *Legal Proceedings*

The information called for by this item is provided in Note 14, Commitments and Contingencies included in the Notes to Consolidated Financial Statements of this report, which information is incorporated into this Item 3 by reference.

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 20, 2007, there were 25,553,306 common units outstanding, held by approximately 13,238 holders, including common units held in street name and by affiliates of Williams.

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As of February 26, 2007, there were 7,000,000 subordinated units outstanding held by four subsidiaries of Williams. The subordinated units are not publicly traded.

As of February 26, 2007, there were 6,805,492 Class B units outstanding, held by 22 holders. The Class B units were issued in December 2006 and are not publicly traded.

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)
2006			
Fourth Quarter	$ 40.80	$ 35.04	$ 0.4700
Third Quarter	36.00	29.25	0.4500
Second Quarter	35.55	30.30	0.4250
First Quarter	33.92	31.00	0.3800
2005			
Fourth Quarter	$ 34.26	$ 29.75	0.3500
Third Quarter(b)	32.75	24.89	0.1484(c)

(a) Represents cash distributions attributable to the quarter and declared and paid or to be paid within 45 days after quarter end. We paid cash distributions to our general partner with respect to its 2% general partner interest that totaled $0.1 million for the period from August 23, 2005 through December 31, 2005. We declared cash distributions to our general partner with respect to its 2% general partner interest and incentive distribution rights that totaled $1.8 million for the 2006 period. No Class B units were outstanding until December 2006 and therefore did not participate in cash distributions prior to the cash distribution for the fourth quarter of 2006.

(b) For the period from August 18, 2005 through September 30, 2005.

(c) The distribution for the third quarter of 2005 represents a pro-rated distribution of $0.35 per common and subordinated unit for the period from August 23, 2005, the date of the closing of our initial public offering of common units through September 30, 2005.

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 generally borrowings that will be made under our working capital facility with Williams and in all cases are used solely for working capital purposes or to pay distributions to partners.

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.35 per quarter,

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plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. In addition, as described in more detail below, the Class B units rank junior to common units in their right to receive distributions but senior of the subordinated units. The Class B units, if any remain outstanding, would continue to rank junior to the common units even after the expiration of the subordination period.

The subordination period will extend until the first day of any quarter beginning after June 30, 2008 that each of the following tests are met:

distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

the adjusted operating surplus (as defined in our partnership agreement) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the general partner interest during those periods; and

there are no arrearages in payment of the minimum quarterly distribution on the common units.

In addition, the subordination period may terminate before June 30, 2008 if the following tests are met:

distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded $2.10 (150% of the annualized minimum quarterly distribution) for the immediately preceding four-quarter period;

the adjusted operating surplus generated during such four-quarter period equaled or exceeded $2.10 (150% of the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units during such four-quarter period on a fully diluted basis and the related distribution on the general partner interest during such four-quarter period; and

there are no arrearages in payment of the minimum quarterly distribution on the common units.

If the unitholders remove our general partner without cause, the subordination period may also end before June 30, 2008.

Upon expiration of the subordination period, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. In addition, 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:

the subordination period will end and each subordinated unit will immediately convert into one common unit;

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.

We will make distributions of available cash from operating surplus for any quarter during any subordination period in the following manner:

first, 98% to the common unitholders, pro rata, and 2% to our general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;

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second, 98% to the common unitholders, pro rata, and 2% to our general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;

third, if any Class B units remain outstanding, 98% to the Class B unitholders, pro rata, and 2% to our general partner, until we distribute for each outstanding Class B unit an amount equal to the minimum quarterly distribution for that quarter;

fourth, if any Class B units remain outstanding, 98% to the Class B unitholders, pro rata, and 2% to our general partner, until we distribute for each outstanding Class B unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the Class B units for any prior quarters;

fifth, if any subordinated units remain outstanding, 98% to the subordinated unitholders, pro rata, and 2% to our general partner, until we distribute for each subordinated unit an amount equal to 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.

The preceding discussion 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. In addition, the description of distributions payable on the Class B units above reflect the distributions payable on the Class B units within 180 days of their issuance on December 13, 2006. The Class B units will convert into common units on a one-for-one basis upon the approval of a majority of the votes cast by common unitholders provided that the total number of votes cast is at least a majority of common units eligible to vote (excluding common units held by Williams and its affiliates). We are required to seek such approval as promptly as practicable and not later than 180 days from December 13, 2006. If we have not obtained the requisite unitholder approval of the conversion of the Class B units within 180 days from December 13, 2006, the Class B units will be entitled to receive 115% of the quarterly distribution and distributions on liquidation payable on each common unit. We expect to call a special meeting of common unitholders in the second quarter of 2007 to seek approval for the conversion of the Class B units.

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%

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

The following table shows selected financial and operating data of Williams Partners L.P. and of Discovery Producer Services LLC for the periods and as of the dates indicated. We derived the financial data as of December 31, 2006 and 2005 and for the years ended December 31, 2006, 2005 and 2004 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.

Because Four Corners was an affiliate of Williams at the time of these acquisitions, these transactions were between entities under common control, and have been accounted for at historical cost. Accordingly, our consolidated financial statements and notes have been restated to reflect the combined historical results of Four Corners throughout the periods presented. These acquisitions have no impact on historical earnings per unit as pre-acquisition earnings were allocated to our general partner.

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,				
	2006	2005	2004	2003	2002
	(Dollars in thousands, except per unit amounts)				
Statement of Income Data:					
Revenues	$ 563,410	$ 514,972	$ 469,199	$ 382,428	$ 349,817
Costs and expenses	420,342	395,556	364,602	286,637	253,417
Operating income	143,068	119,416	104,597	95,791	96,400
Equity earnings Discovery	12,033	8,331	4,495	3,447	2,026
Impairment of investment in Discovery			(13,484)(a)		
Interest expense	(9,833)	(8,238)	(12,476)	(4,176)	(3,414)
Interest income	1,600	165			
Income before cumulative effect of change in accounting principle	$ 146,868	$ 119,674	$ 83,132	$ 95,062	$ 95,012
Net income(b)	$ 146,868	$ 118,352	$ 83,132	$ 93,633	$ 95,012
Income before cumulative effect of change in accounting principle per limited partner unit:					
Common unit	$ 1.62	$ 0.49(d)	N/A	N/A	N/A
B unit	$ 0.45	N/A	N/A	N/A	N/A
Subordinated unit	$ 1.62	$ 0.49(d)	N/A	N/A	N/A
Net income per limited partner unit:					

Common unit	$ 1.62	$ 0.44(d)	N/A	N/A	N/A
B unit	$ 0.45	N/A	N/A	N/A	N/A
Subordinated unit	$ 1.62	$ 0.44(d)	N/A	N/A	N/A
Balance Sheet Data (at period end):					
Total assets	$ 933,148	$ 875,275	$ 863,584	$ 896,739(c)	$ 825,007
Property, plant and equipment, net	647,578	658,965	669,503	705,600	755,131
Investment in Discovery	147,493	150,260	147,281(a)	156,269(c)	49,323
Advances from affiliate			186,024	187,193(c)	90,996
Partners capital	135,402(e)	827,245	637,198	674,533	694,691

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	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(Dollars in thousands, except per unit amounts)				
Cash Flow Data:					
Cash distributions declared per unit	$ 1.605	$ 0.1484	N/A	N/A	N/A
Cash distributions paid per unit	$ 1.605	$ 0.1484	N/A	N/A	N/A
Operating Information:					
Williams Partners L.P.:					
Four Corners gathered volumes (MMBtu/d)	1,499,937	1,521,507	1,559,940	1,577,181	1,594,745
Four Corners processed volumes (MMBtu/d)	875,600	863,693	900,194	900,356	917,613
Four Corners liquid sales gallons(000 s)	182,010	165,479	197,851	187,788	203,688
Four Corners net liquids margin (¢/gallon)	47¢	37¢	29¢	17¢	15¢
Conway storage revenues	$ 25,237	$ 20,290	$ 15,318	$ 11,649	$ 10,854
Conway fractionation volumes (bpd) our 50%	38,859	39,965	39,062	34,989	38,234
Carbonate Trend gathered volumes (MMBtu/d)	29,323	35,605	49,981	67,638	57,060
Discovery Producer Services 100%:					
Gathered volumes (MMBtu/d)	467,338	345,098	348,142	378,745	425,388
Gross processing margin (¢/MMbtu)	23¢	19¢	17¢	17¢	12¢

(a) The $13.5 million impairment of our equity investment in Discovery in 2004 reduced the investment balance. See Note 6 of the Notes to Consolidated Financial Statements.

(b) Our operations are treated as a partnership with each member being separately taxed on its ratable share of our taxable income. Therefore, we have excluded income tax expense from this financial information.

(c) In December 2003, we made a $101.6 million capital contribution to Discovery, which Discovery subsequently used to repay maturing debt. We funded this contribution with an advance from Williams. Prior to the closing of our initial public offering, Williams forgave the entire advances from affiliates balance.

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

(e) Because Four Corners was an affiliate of Williams at the time of its acquisition by us, the acquisition is accounted for as a combination of entities under common control, whereby the assets and liabilities of Four Corners are combined with Williams Partners L.P. 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 the Four Corners 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.

Overview

We are principally engaged in the business of gathering, transporting, processing and treating natural gas and fractionating and storing NGLs. We manage our business and analyze our results of operations on a segment basis. Our operations are divided into three business segments:

Gathering and Processing West. Our West segment includes Williams Four Corners LLC (Four Corners). The Four Corners system gathers and processes or treats approximately 37% of the natural gas produced in the San Juan Basin and connects with the five pipeline systems that transport natural gas to end markets from the basin.

Gathering and Processing Gulf. Our Gulf segment includes (1) our 40% ownership interest in Discovery and (2) the Carbonate Trend gathering pipeline off the coast of Alabama. Discovery owns an integrated natural gas gathering and transportation pipeline system extending from offshore in the Gulf of Mexico to a natural gas processing facility and an NGL fractionator in Louisiana. These assets generate revenues by providing natural gas gathering, transporting and processing services and integrated NGL fractionating services to customers under a range of contractual arrangements. 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.

NGL Services. Our NGL Services segment includes three integrated NGL storage facilities and a 50% undivided interest in a fractionator near Conway, Kansas. These assets generate revenues by providing stand-alone NGL fractionation and storage services using various fee-based contractual arrangements where we receive a fee or fees based on actual or contracted volumetric measures.

Executive Summary

In 2006, the two most important events for our business were the June and December acquisitions of 25.1% and 74.9%, respectively, of Four Corners from Williams. The combined value of these transactions was approximately $1.6 billion, which is a dramatic increase in size from the $100.2 million we raised at our IPO in August of 2005. The acquisition of Four Corners provides us with a large-scale gathering and processing system with stable cash flows and a relatively high percentage of fee-based revenues. The 2006 results of our Gathering and Processing West segment, which includes Four Corners, were exceptionally strong based on record commodity margins for the NGLs it receives under certain processing contracts. However, we also experienced significant increases in operating costs in that segment. Discovery continued work on its important Tahiti lateral expansion project, which remains on schedule to receive initial throughput in the first half of 2008. Discovery also benefited from record commodity margins and the continuation of processing volumes initially received following damage to third-party facilities during Hurricanes Katrina and Rita. In our NGL Services segment, we continued storage cavern workovers and wellhead modifications at Conway while generating increased storage revenues from higher average storage volumes. We have increased distributions each quarter in an aggregate amount of $0.12, or 34%, per unit since our IPO. We believe that we have adequate cash reserves to finance our working capital and maintenance capital requirements, and we have had no borrowings under our revolving credit facilities. Our capitalization and relationship with Williams has us well-positioned to continue to grow through both internal projects and acquisition transactions with Williams and other third parties.

Recent Events

Acquisition of Four Corners. In 2006, in two separate transactions, we acquired 100% of Four Corners from Williams. On June 20, 2006, we acquired a 25.1% membership interest in Four Corners for aggregate consideration of $360.0 million. On December 13, 2006, we acquired the remaining 74.9% membership interest for aggregate consideration of $1.223 billion. These two transactions were financed with the following debt and equity issuances.

Issuance of Common Units. On June 20 and December 13, 2006, respectively, we sold 7,590,000 and 8,050,000 common units (including 990,000 and 1,050,000 common units pursuant to the underwriters over-allotment purchase option) in public offerings. We received net proceeds of approximately $227.1 million and 293.7 million, respectively, from the sale of the common units after deducting underwriting discounts but before estimated offering expenses.

Issuance of Common Units and Class B units in a Private Placement. On December 13, 2006, we sold 2,905,030 common units and 6,805,492 unregistered Class B units in a private placement. We received net proceeds of approximately $346.5 million after deducting placement fees but before estimated offering expenses. The Class B units are convertible into common units on a one-for-one basis upon the approval of a majority of the votes cast by common unitholders, provided that the total number of votes cast is at least a majority of common units eligible to vote (excluding common units held by Williams and its affiliates).

Issuance of Senior Unsecured Notes. On June 20 and December 13, 2006, respectively, we issued $150.0 million and $600.0 million aggregate principal amount of 7.5% and 7.25% senior unsecured notes due 2011 and 2017. We received net proceeds of approximately $146.8 million and $590.0 million from the sale of the senior unsecured notes after deducting initial purchaser discounts and estimated offering expenses.

Because Four Corners was an affiliate of Williams at the time of these acquisitions, these transactions were between entities under common control, and have been accounted for at historical cost. Accordingly, our consolidated financial statements and notes have been restated to include the historical results of Four Corners throughout the periods presented. These two acquisitions of a combined 100% membership interest in Four Corners increased net income $142.7 million, $113.5 million and $96.6 million for 2006, 2005 and 2004, respectively. These acquisitions have no impact on historical earnings per unit as pre-acquisition earnings were allocated to our general partner.

New Credit Facility with Williams. In May 2006, Williams replaced its $1.275 billion secured credit facility with a $1.5 billion unsecured credit agreement. The new facility contains similar terms and covenants as the prior facility. The new credit agreement is available for borrowings and letters of credit and will continue to allow us to borrow up to $75.0 million for general partnership purposes, including acquisitions, but only to the extent that sufficient amounts remain unborrowed by Williams and its other subsidiaries. Please read Financial Condition and Liquidity Credit Facilities for more information.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measures to analyze our segment performance, including the performance of Discovery. These measurements include:

Four Corners gathering and processing volumes;

Four Corners net liquids margin;

Discovery s and Carbonate Trend s pipeline throughput volumes;

Discovery s gross processing margins;

Conway s fractionation volumes;

Conway s storage revenues; and

operating and maintenance expenses.

Four Corners

Gathering and Processing Volumes. The gathering volumes on our Four Corners system and volumes processed at the Ignacio, Kutz and Lybrook natural gas processing plants are important components of maximizing its profitability. We gather approximately 37% of the San Juan Basin s natural gas production on our Four Corners system at approximately 6,400 receipt points under mostly fee-based contracts. Our gathering volumes from existing wells connected to our pipeline will naturally decline over time. Accordingly, to maintain or increase gathering volumes we must continually obtain new supplies of natural gas. Our Four Corners system processes natural gas under keep-whole, percent-of-liquids, fee-based and fee-based and keep-whole contracts. Our processing volumes are largely dependent on the volume of natural gas gathered on our Four Corners system.

Net Liquids Margin. The net liquids margin is an important measure of Four Corners ability to maximize the profitability of its processing operations. Liquids margin is derived by deducting the cost of shrink replacement gas from the revenue Four Corners receives from the sale of its NGLs. Shrink replacement gas refers to natural gas that is required to replace the Btu content lost when NGLs are extracted from the natural gas stream. Under certain agreement types, Four Corners receives NGLs as compensation for processing services provided to its customers. The net liquids margin will either increase or decrease as a result of a corresponding change in the relative market prices of NGLs and natural gas.

Discovery and Carbonate Trend

Pipeline Throughput Volumes. We view throughput volumes on Discovery s pipeline system and our Carbonate Trend pipeline as an important component of maximizing our profitability. We gather and transport natural gas under fee-based contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time. Accordingly, to maintain or increase throughput levels on these pipelines and the utilization rate of Discovery s natural gas processing plant and fractionator, we and Discovery must continually obtain new supplies of natural gas. Our ability to maintain existing supplies of natural gas and obtain new supplies are impacted by (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines and (2) our ability to compete for volumes from successful new wells in other areas. We routinely monitor producer activity in the areas served by Discovery and Carbonate Trend and pursue opportunities to connect new wells to these pipelines.

Gross Processing Margins. We view total gross processing margins as an important measure of Discovery s ability to maximize the profitability of its processing operations. Gross processing margins include revenue derived from:

- the rates stipulated under fee-based contracts multiplied by the actual MMBtu volumes;
- sales of NGL volumes received under certain processing contracts for Discovery s account and keep-whole contracts; and
- sales of natural gas volumes that are in excess of operational needs.

The associated costs, primarily shrink replacement gas and fuel gas, are deducted from these revenues to determine gross processing margin. In certain prior years, such as 2003, we generated significant revenues from the sale of excess natural gas volumes. However, in response to a final rule issued by the FERC in 2004, we expect that Discovery will generate only minimal revenues, if any, from the sale of excess natural gas in the future. However, this rule has been vacated and remanded back to the FERC because the courts found that the FERC offered no evidence of abusive behavior to warrant such restriction.

Discovery s mix of processing contract types and its operation and contract optimization activities are determinants in processing revenues and gross margins.

Conway

Fractionation Volumes. We view the volumes that we fractionate at the Conway fractionator as an important measure of our ability to maximize the profitability of this facility. We provide fractionation services at Conway under fee-based contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes fractionated.

Storage Revenues. Our storage revenues are derived by applying the average demand charge per barrel to the total volume of storage capacity under contract. Given the nature of our operations, our storage facilities have a relatively higher degree of fixed versus variable costs. Consequently, we view total storage revenues, rather than contracted capacity or average pricing per barrel, as the appropriate measure of our ability to maximize the profitability of our storage assets and contracts. Total storage revenues include the monthly recognition of fees received for the storage contract year and shorter-term storage transactions.

Operating and Maintenance Expenses

Operating and maintenance expenses are costs associated with the operations of a specific asset. Direct labor, leased compression services, contract services, fuel, utilities, materials, supplies, insurance and ad valorem taxes comprise the most significant portion of operating and maintenance expenses. We have experienced increased operating and maintenance expenses in recent years due to the growth of the oil and gas industry, which has increased competition for resources. Other than rented compression services and fuel expense, these expenses generally remain relatively stable across broad ranges of throughput volumes but can fluctuate depending on the activities performed during a specific period. For example, plant overhauls and turnarounds result in increased expenses in the periods during which they are performed. Leased compression services are dependent upon the extent and amount of additional compression needed to meet the needs of our Four Corners customers and the cost at which compression can be purchased, leased and operated. We include fuel cost in our operating and maintenance expense although it is generally recoverable from our customers in our NGL Services segment. As noted above, fuel costs in our Gathering and Processing Gulf segment are a component in assessing our gross processing margins.

In addition to the foregoing measures, we also review our general and administrative expenditures, substantially all of which are incurred through Williams. In an omnibus agreement, executed in connection with our IPO, Williams agreed to provide a five-year partial credit for general and administrative expenses incurred on our behalf. The amount of the credit was $3.2 million in 2006 and will decrease by approximately $800,000 in each subsequent year.

We record total general and administrative costs, including those costs that are subject to the credit by Williams, as an expense, and we record the credit as a capital contribution by our general partner. 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.

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. 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 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, 2006, we have an accrued asset retirement obligation liability of $4.5 million for estimated retirement costs associated with the abandonment of Four Corners gas processing and compression facilities located on leased land, its wellhead connections on federal land and Conway s underground storage caverns and brine ponds in accordance with KDHE regulations. 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 in 2006, the recorded asset retirement obligation would have increased by approximately $2.8 million. Our estimate utilizes judgments and assumptions regarding the extent of our obligations, the costs to abandon and the timing of abandonment. Please read Note 8 of Notes to Consolidated Financial Statements.

Environmental Remediation Liabilities

We record liabilities for estimated environmental remediation liabilities when we assess that a loss is probable and the amount of the loss can be reasonably estimated. At December 31, 2006, 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. During 2004, we purchased an insurance policy covering certain of our environmental liabilities. Please read Environmental and Note 14 of Notes to Consolidated Financial Statements for further information.

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Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2006. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	2006	% Change from 2005(1)	2005	% Change from 2004(1)	2004
			(Dollars in thousands)		
Revenues	$ 563,410	+9%	$ 514,972	+10%	$ 469,199
Costs and expenses:					
Product cost and shrink replacement	175,508	+1%	177,527	(16)%	152,963
Operating and maintenance expense	155,214	(20)%	129,759	(11)%	116,446
Depreciation, amortization and accretion	43,692	(3)%	42,579	+4%	44,361
General and administrative expense	39,440	(8)%	36,615	(14)%	32,179
Taxes other than income	8,961	(6)%	8,446	(13)%	7,506
Other (income) expense, net	(2,473)	NM	630	+94%	11,147
Total costs and expenses	420,342	(6)%	395,556	(8)%	364,602
Operating income	143,068	+20%	119,416	+14%	104,597
Equity earnings Discovery	12,033	+44%	8,331	+85%	4,495
Impairment of investment in Discovery				+100%	(13,484)
Interest expense	(9,833)	(19)%	(8,238)	+34%	(12,476)
Interest income	1,600	NM	165	NM	
Income before cumulative effect of change in accounting principle	146,868	+23%	119,674	+44%	83,132
Cumulative effect of change in accounting principle		+100%	(1,322)	NM	
Net income	$ 146,868	+24%	$ 118,352	+42%	$ 83,132

(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.

2006 vs. 2005

Revenues increased $48.4 million, or 9%, due primarily to higher revenues in our Gathering and Processing West segment reflecting increased product sales and gathering and processing revenues as well as increased storage revenues and increased product sales revenues in our NGL Services segment. These increases are discussed in detail in the Results of Operations Gathering and Processing West and Results of Operations NGL Services sections.

Operating and maintenance expense increased $25.5 million, or 20%, due primarily to higher compression, maintenance and labor costs in our Gathering and Processing West segment. These increases are discussed in the Results of Operations Gathering and Processing West section.

Operating income increased $23.7 million, or 20%, due primarily to higher net liquids margins and fee-based revenues, partially offset by higher operating and maintenance expense.

Equity earnings from Discovery increased $3.7 million, or 44%, due primarily to Discovery s higher gross processing margins partially offset by their higher operating and maintenance expense. These increases are discussed in detail in the Results of Operations Gathering and Processing Gulf section.

Interest expense increased $1.6 million, or 19%, due primarily to $8.3 million of interest on our $750.0 million senior unsecured notes. We issued $150.0 million in June 2006 and $600.0 million in December 2006 to finance our acquisition of 100% of Four Corners. This increase was partially offset by $7.4 million lower interest following the forgiveness of advances from Williams in conjunction with the closing of our IPO on August 23, 2005.

Interest income increased $1.4 million due to interest earned on our cash balances following our IPO on August 23, 2005.

2005 vs. 2004

Revenues increased $45.8 million, or 10%, due primarily to higher product sales and gathering and processing revenues in our Gathering and Processing West segment as well as increased storage and product sales revenues in our NGL Services segment.

Product cost and shrink replacement increased $24.6 million, or 16%, directly related to the increase in product sales volumes in our Gathering and Processing West and NGL Services segments.

Operating and maintenance expense increased $13.3 million, or 11%, due primarily to higher maintenance, fuel and power costs in both our Gathering and Processing West and NGL Services segments.

General and administrative expense increased $4.4 million, or 14%, due primarily to the increased costs of being a publicly-traded partnership. These costs included $1.1 million for audit fees, tax return preparation, director fees and registration and transfer agent fees, $0.7 million for direct and specific charges allocated by Williams for accounting, legal and other support, $0.6 million for business development and $0.3 million for other various expenses.

Other (income) expense, net improved $10.5 million, or 94%, due primarily to the 2004 impairment of our Four Corners LaMaquina carbon dioxide treating facility and other 2004 losses on asset dispositions and materials and supplies inventory adjustments.

Operating income increased $14.8 million, or 14%, due primarily to higher fee-based revenues and net liquids margins in our Gathering and Processing West segment and the absence of a 2004 impairment charge, partially offset by higher operating and maintenance expenses.

Equity earnings from Discovery increased $3.8 million due primarily to Discovery s 2005 recognition of deferred gains and higher revenues, partially offset by their increased expenses. This increase is discussed in detail in the Results of Operations Gathering and Processing Gulf section.

The 2004 impairment of our investment in Discovery is the result of our analysis pursuant to which we concluded that we had experienced an other than temporary decline in the fair value of our investment in Discovery.

Interest expense decreased $4.2 million, or 34%, due primarily to the forgiveness of advances from Williams in conjunction with the closing of the IPO on August 23, 2005.

The Cumulative effect of change in accounting principle of $1.3 million in 2005 relates to our December 31, 2005 adoption of Financial Accounting Standards Board Interpretation (FIN) No. 47. Please read Note 8 of Notes to Consolidated Financial Statements.

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Results of operations Gathering and Processing West

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

	2006	2005	2004
		(In thousands)	
Segment revenues	$ 502,313	$ 463,203	$ 428,223
Costs and expenses:			
Product cost and shrink replacement	159,997	165,706	146,328
Operating and maintenance expense	124,763	104,648	97,070
Depreciation, amortization and accretion	40,055	38,960	40,675
General and administrative expense direct	11,920	12,230	8,500
Taxes other than income	8,245	7,746	6,790
Other (income) expense, net	(2,476)	636	11,238
Total costs and expenses, including interest income	342,504	329,926	310,601
Segment profit	$ 159,809	$ 133,277	$ 117,622

2006 vs. 2005

Revenues increased $39.1 million, or 8%, due primarily to $24.6 million higher product sales and $14.3 million higher gathering and processing revenues. Product sales increased due primarily to:

$14.9 million related to a 12% increase in NGL volumes that we received under certain processing contracts. This increase was related primarily to equipment outages in 2005 and reduced ethane processing in the fourth quarter of 2005 caused by sharply higher natural gas prices following the hurricanes of 2005;

$13.5 million related to a 10% increase in average NGL sales prices realized on sales of NGLs which we received under certain processing contracts. This increase resulted from general increases in market prices for these commodities between the two periods;

$4.1 million of higher condensate sales, which includes $1.9 million resulting from the recognition of two additional months of condensate revenue in 2006. Prior to 2006, condensate revenue had been recognized two months in arrears. As a result of more timely sales information now made available from third parties, we have recorded these on a current basis and thus have fully recognized this activity through December 31, 2006. Our management concluded that the effect of recording the additional two months was not material to our results for 2006, prior periods or our trend of earnings; and

$1.1 million of higher LNG sales related to an increase in volumes sold.

These product sales increases were partially offset by $9.0 million lower sales of NGLs on behalf of third party producers for whom we purchase their NGLs for a fee under their contracts. Under these arrangements, we purchase the NGLs from the third party producers and sell them to an affiliate. This decrease is offset by lower associated product costs of $9.0 million discussed below.

The $14.3 million increase in fee-based gathering and processing revenues is due primarily to $15.2 million higher revenue from a 7% increase in the average gathering and processing rates, partially offset by $0.9 million lower revenue from a slight decrease in gathering and processing volumes. The average gathering and processing rates increased in 2006 largely as a result of inflation-sensitive contractual escalation clauses. One significant gathering agreement is adjusted based on changes in the average price of natural gas.

Product cost and shrink replacement gas costs decreased $5.7 million, or 3%, due primarily to:

a $9.0 million decrease from third party producers who elected to have us purchase their NGLs which was offset by the corresponding decrease in product sales discussed above; and

a $6.0 million decrease from 8% lower average natural gas prices.

These decreases were partially offset by a $9.8 million increase from 16% higher volumetric shrink requirements under our Four Corners keep-whole processing contracts.

Operating and maintenance expense increased $20.1 million, or 19%, due primarily to:

a $13.4 million increase in materials and supplies, outside services and other operating expenses related primarily to increased compression and maintenance costs;

a $4.7 million increase in labor and benefits caused by higher Williams annual incentive program costs and the addition of new personnel; and

a $2.0 million increase in non-shrink natural gas purchases due primarily to higher volumetric gathering fuel requirements and higher system losses.

Other (income) expense, net improved $3.1 million due primarily to a $3.6 million gain recognized on the sale of the LaMaquina treating facility in the first quarter of 2006. The LaMaquina treating facility was shut down in 2002 and impairments were recorded in 2003 and 2004.

Segment profit increased $26.5 million, or 20%, due primarily to $24.7 million of higher net liquids margins resulting primarily from increased per-unit margins on higher NGL sales volumes, $14.3 million of higher fee-based gathering and processing revenues, $5.2 million from higher condensate and LNG sales, and the $3.5 million improvement in other (income) expense, net. These increases were partially offset by $20.1 million higher operating and maintenance expense.

2005 vs. 2004

Revenues increased $35.0 million, or 8%, due primarily to $26.4 million higher product sales and $9.8 million higher gathering and processing revenue. Product sales revenues increased due primarily to:

a $21.5 million increase in the sale of liquids on behalf of third parties. These NGL sales were made on behalf of producers who have us purchase their NGLs for a fee in accordance with their contracts. This increase was offset by higher associated product costs of $21.5 million discussed below;

$21.1 million related to 21% higher average NGL sales prices realized for the volumes we received under our processing contracts;

$3.0 million higher LNG sales; and

$2.9 million higher condensate sales.

These increases were partially offset by $22.1 million related to 18% lower NGL volumes received under our processing contracts. In 2005, a customer exercised an annual option to switch from a keep-whole contract to a fee-based contract, which decreased the NGL volumes that we retained.

Fee-based gathering and processing revenues increased $9.8 million due to $17.1 million higher revenue from a 8% increase in the average gathering and processing rates, partially offset by $7.3 million lower revenue from 3% lower gathering volumes. The average gathering and processing rates increased in 2005 largely as a result of inflation-sensitive contractual escalation clauses. The volume decrease was driven by normal reservoir declines, which were partially offset by new well connects. The overall net decline is related primarily to the slightly steeper decline rate associated with coal bed methane production. Historically, we have substantially offset the impact of production declines at Four Corners with new well connects.

Products cost, primarily shrink replacement gas, increased $19.4 million, or 13%, due primarily to the $21.5 million increase from third party customers who elected to have us purchase their NGLs and

$15.1 million from a 30% increase in the average price of natural gas, partially offset by $17.2 million from 26% lower volumetric shrink requirements from our keep-whole processing contracts resulting from a customer exercising an annual option to switch from a keep-whole contract to a fee-based contract.

Operating and maintenance expense increased $7.6 million, or 8%, due primarily to:

$5.1 million higher materials and supplies and outside services expense related to increased repair and maintenance activity;

$2.7 million of higher natural gas cost related to fuel and system gains and losses; and

$1.8 million of higher compressor costs from inflation-indexed escalation clauses in operating and maintenance agreements and additional rental units.

These increases were partially offset by $2.0 million of other various operating and maintenance expense decreases.

General and administrative direct expense increased $3.7 million, or 44%, due primarily to including certain management costs that were directly charged in 2005 and allocated in 2004.

Other (income) expense, net improved $10.6 million, from $11.2 million in 2004, due primarily to the following 2004 charges that were not present in 2005:

$7.6 million impairment charge for the LaMaquina treating facility in 2004. The LaMaquina treating facility shut down in 2002 and was sold in the first quarter of 2006;

$1.2 million loss on asset dispositions; and

$1.0 million for materials and supplies inventory adjustments.

Segment profit increased $15.7 million, or 13%, due primarily to $9.8 million higher gathering and processing revenues, $7.0 million higher product sales margins on lower NGL sales volumes and lower other expenses of $10.6 million, partially offset by $7.6 million higher operating and maintenance expenses and $3.7 million higher general and administrative direct expenses.

Outlook 2007

Throughput volumes on our Four Corners gathering, processing and treating system are an important component of maximizing its profitability. Throughput volumes from existing wells connected to its pipelines will naturally decline over time. Accordingly, to maintain or increase throughput levels we must continually obtain new supplies of natural gas.

In 2007, we anticipate that sustained drilling activity, expansion opportunities and production enhancement activities by existing customers should be sufficient to more than offset the historical decline and increase gathered and processed volumes.

We have realized above average margins at our gas processing plants in recent years due primarily to increasing prices for NGLs. We expect per-unit margins in 2007 will remain higher in relation to five- year historical averages but below the record levels realized in 2006. Additionally, we anticipate that our contract mix and commodity management activities at Four Corners will continue to allow us to realize greater margins relative to industry benchmark averages.

We anticipate that operating costs, excluding compression, will remain stable as compared to 2006. Compression cost increases are dependent upon the extent and amount of additional compression needed to meet the needs of our Four Corners customers and the cost at which compression can be purchased, leased and operated.

We are conducting negotiations with the Jicarilla Apache Nation in Northern New Mexico for the renewal of certain rights of way on reservation lands. The current right of way agreement, which covers certain gathering system assets in Rio Arriba County, New Mexico, expired on December 31, 2006. We continue to operate our assets on these reservation lands pursuant to a three-month agreement while we

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conduct further discussions that could result in renewal of our rights of way, sale of the gathering assets on reservation lands or other options that might be in the mutual interest of both parties.

Results of operations Gathering and Processing Gulf

The Gulf segment includes the Carbonate Trend gathering pipeline and our 40% ownership interest in Discovery.

	2006	2005	2004
		(In thousands)	
Segment revenues	$ 2,656	$ 3,515	$ 4,833
Costs and expenses:			
Operating and maintenance expense	1,660	714	572
Depreciation	1,200	1,200	1,200
General and administrative expense direct	1	2	
Total costs and expenses	2,861	1,916	1,772
Segment operating income (loss)	(205)	1,599	3,061
Equity earnings Discovery	12,033	8,331	4,495
Impairment of investment in Discovery			(13,484)
Segment profit (loss)	$ 11,828	$ 9,930	$ (5,928)

Carbonate Trend

2006 vs. 2005

Segment operating income decreased $1.8 million from income of $1.6 million in 2005 to a loss of $0.2 million in 2006 due to the $0.9 million increase in operating and maintenance expense associated mainly with increased insurance premiums resulting from hurricanes. Additionally, operating income decreased due to the absence of $0.5 million in revenues from the settlement of a contractual volume deficiency payment recognized in 2005 and lower gathering revenues.

2005 vs. 2004

Segment operating income decreased $1.5 million, or 48%, due primarily to lower gathering revenues and the absence of $1.0 million of revenue from the settlement of a contractual volume deficiency payment recognized in 2004, partially offset by $0.5 million of revenue from the settlement of a contractual volume deficiency payment recognized in 2005.

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.

	2006	2005	2004
		(In thousands)	
Revenues	$ 197,313	$ 122,745	$ 99,876
Costs and expenses, including interest:			
Product cost and shrink replacement	119,552	64,467	45,355
Operating and maintenance expense	23,049	10,165	17,854
General and administrative expense	2,150	2,053	1,424
Depreciation and accretion	25,562	24,794	22,795
Interest income	(2,404)	(1,685)	(550)
Other (income)expense, net	(679)	2,123	1,328
Total costs and expenses	167,230	101,917	88,206
Net income before cumulative effect of change in accounting principle	$ 30,083	$ 20,828	$ 11,670
Williams Partners 40% interest	$ 12,033	$ 8,331	$ 4,668
Capitalized interest amortization			(173)
Equity earnings per our Consolidated Statement of Income	$ 12,033	$ 8,331	$ 4,495

2006 vs. 2005

Revenues increased $74.6 million, or 61%, due primarily to higher NGL product sales from the purchasing of customers NGLs. In addition, the Tennessee Gas Pipeline (TGP) and the Texas Eastern Transmission Company (TETCO) open season agreements, which began in the last quarter of 2005, contributed an increase of $7.5 million. The open seasons provided outlets for natural gas that was stranded following damage to third-party facilities during hurricanes Katrina and Rita. TGP s open season contract came to an end in early 2006. TETCO s volumes continued throughout 2006, and in October we signed a one-year contract, which is discussed further in the Outlook section. The significant components of the revenue increase are addressed more fully below.

Product sales increased $59.9 million for NGL sales related to third-party processing customers elections to have Discovery purchase their NGLs under an option in their contracts. These sales were offset by higher associated product costs of $59.9 million discussed below.

Product sales also increased $18.1 million due to a 54% increase in NGL volumes that Discovery received under certain processing contracts and $5.3 million due to 10% higher average NGL sales prices related to these volumes. NGL sales volumes in 2006 were higher due partly to the lack of hurricane-related disruptions in 2006. In addition, exceptionally strong commodity margins compelled our customers to process their natural gas rather than by-pass, which led to higher product sales revenues on our percent-of-liquids and keep-whole processing contracts.

Transportation revenues increased $3.1 million, including $2.4 million in additional fee-based revenues related to the TGP and TETCO open season agreements discussed above.

Fee-based processing and fractionation revenues increased $2.7 million due primarily to $5.1 million in additional fee-based revenues related to processing the TGP and TETCO open seasons volumes discussed above, partially offset by lower by-pass revenues.

Partially offsetting these increases were the following:

Product sales decreased $10.0 million due to the absence of excess fuel and shrink replacement gas sales.

Gathering revenues decreased $3.8 million due primarily to lower gathered volumes and rates and a $1.4 million deficiency payment received in the first quarter of 2005.

Product cost and shrink replacement increased $55.1 million, or 85%, due primarily to $59.9 million higher product purchase costs for the processing customers who elected to have Discovery purchase their NGLs and $6.7 million higher costs related primarily to increased processing volumes in 2006, partially offset by a $10.0 million decrease due to the absence of excess fuel and shrink replacement gas sales in 2006.

Operating and maintenance expense increased $12.9 million, or 127%, due primarily to a $10.7 million credit recognized in 2005 related to amounts previously deferred for net system gains from 2002 through 2004. These deferred gains were recognized following the acceptance in 2005 of a filing with the FERC. Additionally, Discovery had higher fuel costs caused by increased processing activity, $1.8 million higher property insurance premiums related to the increased hurricane activity in the Gulf Coast region in prior years, partially offset by $1.0 million insurance deductible expensed in 2005.

Depreciation and accretion expense increased $0.7 million, or 3%, due primarily to the market expansion project placed in service in September 2005.

Interest income increased $0.7 million due primarily to interest earned on funds restricted for use in the construction of the Tahiti pipeline lateral expansion project.

Other (income) expense, net improved $2.8 million due primarily to a net improvement of $3.1 million in foreign currency transaction gains from the revaluation of restricted cash accounts denominated in Euros. These restricted cash accounts were established from contributions made by Discovery s members, including us, for the construction of the Tahiti pipeline lateral expansion project. We are required to pay a significant portion of the construction costs in Euros.

Net income increased $9.3 million, or 44%, due primarily to $18.1 million higher gross processing margins and $7.5 million higher revenues from TGP and TETCO open seasons, partially offset by $12.9 million higher operating and maintenance and $3.8 million lower gathering revenues.

2005 vs. 2004

Revenues increased $22.9 million, or 23%, due primarily to higher NGL product sales from purchasing of customers NGLs, fractionation revenue, processing revenue and average per-unit NGL sales prices, partially offset by lower NGL sales volumes. The significant components of this increase include the following.

Product sales increased $31.6 million for the NGL sales related to third-party processing customers election to have Discovery purchase their NGLs under an option in their contracts. These sales were offset by higher associated product costs of $31.6 million discussed below.

Processing and fractionation revenues increased $6.8 million due primarily to $3.9 million in additional volumes related to the TGP and TETCO open seasons discussed previously, $2.9 million related to an increase in the fractionation rate for increased natural gas fuel cost pass through, and other increases related to new volumes from the Front Runner prospect that came on line in the first quarter of 2005.

Gathering revenues increased $2.1 million due primarily to a $1.4 million deficiency payment received in 2005 related to a volume shortfall under a transportation contract, $0.4 million related to an increase in volumes and $0.3 million related to a 25% higher average gathering rate associated with new volumes from the Front Runner prospect.

Partially offsetting these increases were the following:

Product sales decreased approximately $16.0 million as a result of 36% lower NGL sales volumes following Hurricanes Katrina and Rita, partially offset by a $5.0 million increase associated with a 17% higher average sales prices.

Product sales also decreased $4.9 million as a result of lower sales of excess fuel and shrink replacement gas in 2005. During the first half of 2004 increased natural gas prices made it more economical for Discovery s customers to bypass the processing plant rather than process the gas, leaving Discovery with higher levels of excess fuel and replacement gas in 2004 than 2005.

Transportation revenues decreased $0.6 million due primarily to lower condensate transportation volumes. Higher average natural gas transportation volumes were partially offset by a lower average natural gas transmission rate.

Other revenues declined $1.1 million due largely to lower platform rental fees.

Product cost and shrink replacement increased $19.1 million, or 42%, due primarily to:

$31.6 million increased purchase costs for the two processing customers who elected to have Discovery purchase their NGLs; and

$3.4 million resulting from higher average per-unit natural gas prices.

Partially offsetting these increases were the following:

$11.0 million lower costs related to reduced processing activity in 2005 following Hurricanes Katrina and Rita; and

$4.9 million lower costs associated with sales of excess fuel and shrink natural gas.

Operating and maintenance expense decreased $7.7 million, or 43%, due primarily to a $10.7 million credit related to amounts previously deferred for net system gains from 2002 through 2004. These deferred gains were recognized following the acceptance in 2005 of a filing with the FERC. Partially offsetting this was $1.2 million higher utility costs, $1.0 million of uninsured damages caused by Hurricane Katrina and $0.8 million other miscellaneous operational costs.

General and administrative expense increased $0.6 million, or 44%, due primarily to an increase in the management fee paid to Williams related to Discovery s market expansion project and additions of other facilities. For a discussion of Discovery s recently completed market expansion project, please read Business The Discovery Assets Discovery Natural Gas Pipeline System.

Depreciation and accretion expense increased $2.0 million, or 9%, due primarily to the completion of a pipeline connection to the Front Runner prospect in late 2004.

Interest income increased $1.1 million, due primarily to increases in interest-bearing cash balances during early 2005 period when cash flows from operations were being retained by Discovery.

Other expenses, net increased $0.8 million, or 60%, due primarily to a non-cash foreign currency transaction loss from the revaluation of restricted cash accounts denominated in Euros. These restricted cash accounts were established from contributions made by Discovery s members, including us, for the construction of the Tahiti pipeline lateral expansion project.

Net income increased $9.2 million, or 78%, due primarily to the $10.7 million deferred gain recognition, $8.9 million increased revenue from gathering, processing and fractionation services and $1.1 million higher interest income, partially offset by $3.5 million lower product sales margins, $3.0 million higher other operating and maintenance expense, $0.6 million higher general and administrative expense, $2.0 million higher depreciation and accretion and $0.8 higher other expense including the foreign currency transaction loss.

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Outlook for 2007

Carbonate Trend

In compliance with applicable permit requirements, we completed a survey of portions of our Carbonate Trend pipeline. As a result of this survey, we have determined that it will be necessary to undertake certain restoration activities to repair the partial erosion of the pipeline overburden caused by Hurricane Ivan in September, 2004 and Hurricane Katrina in August 2005. We estimate that these restoration activities could be completed by the end of 2007. During these repairs, the pipeline would be shut down for approximately 40 days, which would decrease our cash flows from operations by approximately $0.3 million. We would fund these repairs with cash flows from operations and seek reimbursement from our insurance carrier and/or contractual counterparties. Additionally, in the omnibus agreement, Williams agreed to reimburse us for the cost of the restoration activities related to Hurricane Ivan to the extent that we are not reimbursed by our insurance carrier and subject to an overall limitation of $14.0 million for all indemnified environmental and related expenditures generally for a period of three years that ends in August 2008. We are assessing our options for meeting our obligations with respect to these restoration activities.

Discovery

Throughput volumes on Discovery s pipeline system are an important component of maximizing its profitability. Pipeline throughput volumes from existing wells connected to its pipelines will naturally decline over time. Accordingly, to maintain or increase throughput levels on these pipelines and the utilization rate of Discovery s natural gas plant and fractionator, Discovery must continually obtain new supplies of natural gas.

The Tahiti pipeline lateral expansion project is currently on schedule. We expect construction will be completed in the second quarter of 2007 and anticipate initial throughput will begin in the first half of 2008. We expect this agreement will have a significant favorable impact on Discovery s revenues.

Discovery signed a one-year processing contract with TETCO effective October 2006 for a minimum volume of 100 BBtu/d and a maximum of 300 BBtu/d. Current flowing volume under this contract is 160 BBtu/d.

With the current oil and natural gas price environment, drilling activity across the shelf and the deepwater of the Gulf of Mexico has been robust. However, the limited availability of specialized rigs necessary to drill in the deepwater areas, such as those in and around Discovery s gathering areas, limits the ability of producers to bring identified reserves to market quickly. This will prolong the timeframe over which these reserves will be developed. We expect Discovery to be successful in competing for a portion of these new volumes.

On March 31, 2006, Discovery connected a new well in ATP Oil & Gas Corporation s Gomez prospect; currently the rate is approximately 40 BBtu/d. We expect the rate to increase from this level in the third quarter of 2007.

In October 2006 we signed an agreement with Walter Oil and Gas Corp. which is producing approximately 25 BBtu/d.

In December 2006 we signed an agreement with Energy Partner s LTD, which will result in approximately 10 BBtu/d of throughput beginning in the first quarter of 2007.

Insurance premiums have increased dramatically from approximately $2.3 million in 2005 to the current level of $4.9 million in 2006. We have no reason to expect premiums to materially change from this amount in the near term.

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Results of operations NGL Services

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

	2006	2005 (In thousands)	2004
Segment revenues	$ 58,441	$ 48,254	$ 36,143
Costs and expenses:			
Operating and maintenance expense	28,791	24,397	18,804
Product cost	15,511	11,821	6,635
Depreciation and accretion	2,437	2,419	2,486
General and administrative expense direct	1,149	1,068	535
Other, net	719	694	625
Total costs and expenses	48,607	40,399	29,085
Segment profit	$ 9,834	$ 7,855	$ 7,058

2006 vs. 2005

Segment revenues increased $10.2 million, or 21%, due primarily to higher storage, product sales and other revenues. The significant components of these revenue increases are addressed more fully below.

Storage revenues increased $4.9 million due primarily to higher average storage volumes from additional short-term storage leases caused by the reduced demand for propane during the mild 2006 winter and storage customers who held their NGLs in storage due to an inclining forward market.

Product sales were $2.6 million higher due primarily to the sale of surplus volumes created through our product optimization activities. This increase was more than offset by the related increase in product cost discussed below.

Other revenues increased $1.7 million due primarily to $1.3 million of fees charged for low sulfur natural gasoline upgrades that began in 2006.

Operating and maintenance expense increased $4.4 million, or 18%, due primarily to increased storage cavern workovers and increases to Conway s environmental remediation liability, partially offset by favorable changes in product imbalance adjustments.

Product cost increased $3.7 million, or 31%, due to the higher product sales volumes discussed above as well as an increase in per-unit costs of 21%.

Segment profit increased $2.0 million, or 25%, due primarily to $10.2 million higher revenues, substantially offset by $8.1 million higher product cost and operating and maintenance expense.

2005 vs. 2004

Segment revenues increased $12.1 million, or 34%, due primarily to higher product sales, storage and fractionation revenues. The significant components of the increase include the following:

Product sales were $5.0 million higher due primarily to the sale of surplus propane volumes created through our product optimization activities. This increase was partially offset by the related increase in product cost discussed below.

Storage revenues increased $5.0 million due primarily to higher average per-unit storage rates for 2005 and higher storage volumes from additional short-term storage leases caused by the reduced demand for propane due to unusually warm temperatures in the early winter months of 2005 and an overall increase in butane and storage volumes.

Fractionation revenues increased $1.7 million due primarily to a 17% increase in the average fractionation rate related to the pass through to customers of increased fuel and power costs and higher volumes in 2005.

Operating and maintenance expense increased $5.6 million, or 30%, due primarily to increased fuel and power costs, some of which we are able to pass through to our customers, and increased product imbalance valuation adjustments.

Product cost increased $5.2 million, or 78%, directly related to increased sales of surplus propane volumes created through our product optimization activities.

General and administrative expense direct increased $0.5 million, or 100%, due primarily to increased operational and technical support for these assets.

Segment profit increased $0.8 million, or 11%, due primarily to the $6.7 million higher storage and fractionation revenues, partially offset by $5.6 million higher operating and maintenance expense.

Outlook for 2007

In 2006 we experienced record physical storage volumes largely related to increased demand for short-term storage leases. This increase in short-term leases was caused primarily by reduced demand for propane during the mild 2005-2006 winter and storage customers who held their NGLs in storage due to an inclining forward market. In 2007, we expect demand for our storage services to remain strong in relation to historic averages but we do not expect to realize the same level of short-term storage leases as experienced in 2006.

We continue to execute a large number of storage cavern workovers and wellhead modifications to comply with KDHE regulatory requirements. We expect outside service costs to continue at current levels throughout 2007 and 2008 to ensure that we meet the regulatory compliance requirement to complete cavern wellhead modifications before the end of 2008. Our forecast for 2007 is to workover approximately 59 caverns (both complete and partial) compared to 51 cavern workovers (38 complete and 13 partial) in 2006.

Financial Condition and Liquidity

We believe we have the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures, debt service and quarterly cash distributions. We anticipate our sources of liquidity for 2007 will include:

Cash and cash equivalents on hand;

Cash generated from operations, including cash distributions from Discovery;

Insurance or other recoveries related to the Carbonate Trend overburden restoration, which should be received, approximately, as costs are incurred;

Capital contributions from Williams pursuant to an omnibus agreement; and

Credit facilities, as needed.

Our cash and cash equivalents increased $16.5 million and $19.2 million on June 20, 2006 and December 13, 2006, respectively, upon the completion of our acquisitions of 25.1% and 74.9% ownership interests in Four Corners. These amounts represent excess net proceeds generated by our offerings of common units and issuances of senior unsecured notes above the consideration paid to Williams for the respective Four Corners interests. We have retained this cash to be used for general partnership purposes.

We anticipate our more significant cash requirements for 2007 to be:

- Maintenance capital expenditures for our Four Corners and Conway assets;

- Expansion capital expenditures for our Four Corners assets;

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Carbonate Trend overburden restoration;

Interest on our long-term debt; and

Quarterly distributions to our unitholders.

Discovery

Discovery expects to make quarterly distributions of available cash to its members pursuant to the terms of its limited liability company agreement. Discovery made the following 2006-2007 distributions to its members (all amounts in thousands):

Date of Distribution	Total Distribution to Members	Our 40% Share
1/31/06	$ 11,000	$ 4,400
4/28/06	$ 9,000	$ 3,600
7/31/06	$ 10,000	$ 4,000
10/30/06	$ 11,000	$ 4,400
1/30/07	$ 9,000	$ 3,600

In 2005, Discovery sustained damages from Hurricane Katrina. The estimated total cost for hurricane-related repairs is approximately $26.0 million, including $24.5 million in potentially reimbursable expenditures in excess of its deductible. Of this amount, $17.5 million has been spent as of December 31, 2006. Discovery is funding these repairs with cash flows from operations and is seeking reimbursement from its insurance carrier. As of December 31, 2006, Discovery has received $4.9 million from the insurance carriers and has an insurance receivable balance of $12.6 million.

We expect future cash requirements for Discovery relating to working capital and maintenance capital expenditures to be funded from its own internally generated cash flows from operations. Growth or expansion capital expenditures for Discovery will be funded either by cash calls to its members, which requires unanimous consent of the members except in limited circumstances, or from internally generated funds.

Capital Contributions from Williams

Capital contributions from Williams required under the omnibus agreement consist of the following:

Indemnification of environmental and related expenditures, less any related insurance recoveries, for a period of three years (for certain of those expenditures) up to a cap of $14 million. Amounts expected to be incurred in 2007 related to these indemnifications are as follows:

approximately $2.9 million for capital expenditures related to KDHE-related cavern compliance at our Conway storage facilities;

and approximately $1.2 million for our 40% share of Discovery s costs for marshland restoration and repair or replacement of Paradis emission-control flare.

In addition, should we undertake the repair, we would incur repair costs related to the partial erosion of the Carbonate Trend pipeline overburden by Hurricane Ivan in 2004. We expect all costs related to this repair will be recoverable from insurance, but to the extent they are not, we will seek indemnification under the omnibus agreement. We are assessing our options for meeting our obligations with respect to these restoration activities. As of December 31, 2006 we have received $2.5 million from Williams for indemnified items since inception of the agreement in August 2005. Thus, approximately $11.5 million remains for reimbursement of our costs on these items.

An annual credit for general and administrative expenses of $2.4 million in 2007, $1.6 million in 2008 and $0.8 million in 2009.

Up to $3.4 million to fund our 40% share of the expected total cost of Discovery s Tahiti pipeline lateral expansion project in excess of the $24.4 million we contributed during September 2005. As of December 31, 2006 we have received $1.6 million from Williams for this indemnification.

Credit Facilities

We may borrow up to $75.0 million under Williams $1.5 billion revolving credit facility, which is available for borrowings and letters of credit. Borrowings under this facility mature on May 1, 2009. Our $75.0 million borrowing limit under Williams revolving credit facility is available for general partnership purposes, including acquisitions, but only to the extent that sufficient amounts remain unborrowed by Williams and its other subsidiaries. At December 31, 2006, letters of credit totaling $29.0 million had been issued on behalf of Williams by the participating institutions under this facility and no revolving credit loans were outstanding.

We also have a $20.0 million revolving credit facility with Williams as the lender. The facility was amended and restated on August 7, 2006. The facility is available exclusively to fund working capital borrowings. Borrowings under the amended and restated facility will mature on June 29, 2009. We are required to reduce all borrowings under this facility to zero for a period of at least 15 consecutive days once each 12-month period prior to the maturity date of the facility. As of December 31, 2006 we had no outstanding borrowings under the working capital credit facility.

Capital Requirements

The natural gas gathering, treating, processing and transportation, and NGL fractionation and storage businesses are 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 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; and

- Expansion capital expenditures such as those 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.

We estimate that maintenance capital expenditures for the Conway assets will be approximately $11.0 million for 2007. Of this amount, we estimate approximately $3.0 million may be reimbursed by Williams subject to the omnibus agreement. We expect to fund the remainder of these expenditures through cash flows from operations. These expenditures relate primarily to cavern workovers and wellhead modifications necessary to comply with KDHE regulations.

We estimate that expansion capital expenditures for the Conway assets will be approximately $2.0 million for 2007.

We estimate that maintenance capital expenditures for Four Corners will be approximately $25.0 million for 2007. We expect Four Corners will fund its maintenance capital expenditures through its cash flows from operations. These expenditures include approximately $13.0 million related to well connections necessary to connect new sources of throughput for the Four Corners system which serve to offset the historical decline in throughput volumes.

We estimate that expansion capital expenditures for Four Corners will be approximately $19.0 million for 2007. We expect Four Corners will fund its expansion capital expenditures through its cash flows from operations. These expenditures include estimates of approximately $6.0 million for certain well connections that we believe will increase throughput volumes in 2007.

We estimate that maintenance capital expenditures for 100% of Discovery will be approximately $7.0 million for 2007. Of this amount, we estimate our 40% share of approximately $3.0 million may be reimbursed by Williams subject to the omnibus agreement. We expect Discovery will fund the remainder of its maintenance capital expenditures through its cash flows from operations. These maintenance capital expenditures relate to numerous smaller projects.

We estimate that expansion capital expenditures for 100% of Discovery will be approximately $39.0 million for 2007, of which our 40% share is $16.0 million. Of the 100% amount, approximately $33.0 million is for the ongoing construction of the Tahiti pipeline lateral expansion project. Discovery will fund these expenditures with amounts previously escrowed for this project.

Carbonate Trend Overburden Restoration

Should we undertake the repair, we would incur repair costs related to the partial erosion of the Carbonate Trend pipeline overburden by Hurricane Ivan in 2004 and Hurricane Katrina in 2005. We would fund these repairs with cash flows from operations and then seek reimbursement from insurance and/or contractual counterparties. We are assessing our options for meeting our obligations with respect to these restoration activities.

Debt Service Long-Term Debt

In June 2006, we and Williams Partners Finance Corporation (Williams Partners Finance) issued $150.0 million aggregate principal amount of senior unsecured notes. Williams Partners Finance Corporation is our wholly owned subsidiary organized for the sole purpose of co-issuing our debt securities. The senior unsecured notes bear interest at 7.5% per annum payable semi-annually in arrears on June 15 and December 15 of each year. We made the first payment on December 15, 2006. The senior notes mature on June 15, 2011.

Additionally, on December 13, 2006, we and Williams Partners Finance issued $600.0 million aggregate principal of 7.25% senior unsecured notes in a private debt placement. The maturity date of the notes is February 1, 2017. Interest is payable semi-annually in arrears on February 1 and August 1 of each year, beginning on August 1, 2007.

In connection with the issuance of the 7.5% and 7.25% senior unsecured notes, we entered into registration rights agreements with the initial purchasers whereby we agreed to conduct registered exchange offers of exchange notes in exchange for the senior unsecured notes or cause to become effective a shelf registration statement providing for resale of the senior unsecured notes. If we fail to file a registration statement with the SEC within 270 days of the respective closing dates, we will be required to pay liquidated damages in the form of additional cash interest to the holders of the notes. Upon the occurrence of such a failure to comply, the interest rate on the senior unsecured notes shall be increased by 0.25% per annum during the 90-day period immediately following the occurrence of such failure to comply and shall increase by 0.25% per annum 90 days thereafter until all defaults have been cured, but in no event shall such aggregate additional interest exceed 0.50% per annum.

Cash Distributions to Unitholders

We paid quarterly distributions to common and subordinated unitholders and our general partner interest after every quarter since our IPO on August 23, 2005. Our most recent quarterly distribution of $19.5 million was paid on February 14, 2007 to the general partner interest and common, Class B and subordinated unitholders of record at the close of business on February 7, 2007. This distribution included an additional incentive distribution to our general partner of approximately $0.6 million.

Results of Operations Cash Flows

Williams Partners L.P.

	2006	2005	2004

	(In thousands)		
Net cash provided by operating activities	$ 173,817	$ 157,932	$ 137,090
Net cash used by investing activities	(628,580)	(55,666)	(15,454)
Net cash provided (used) by financing activities	505,465	(95,427)	(121,636)

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The $15.9 million increase in net cash provided by operating activities for 2006 as compared to 2005 is due primarily to $24.1 million increase in operating income as adjusted for non-cash items and a $16.4 million increase in distributed earnings from Discovery, partially offset by a $29.4 million increase in cash used for working capital. The increase in cash used for working capital was caused primarily by an increase in affiliate receivables as a result of Four Corners transition from Williams cash management program to our cash management program, and other changes in accounts payable. The $20.8 million increase in net cash provided by operating activities in 2005 as compared to 2004 is due primarily to $8.4 million higher operating income, adjusted for non-cash items, and $8.1 million in cash provided from changes in working capital related primarily to a change in the shrink replacement gas imbalance.

Net cash used by investing activities in 2006 relates primarily to the $608.3 million acquisition of Four Corners. Because Four Corners was an affiliate of Williams at the time of these acquisitions, these transactions are accounted for as a combination of entities under common control and the acquisition is recorded at historical cost rather than the actual consideration paid to Williams. Net cash used by investing activities in 2005 includes our capital contribution of $24.4 million to Discovery for construction of the Tahiti pipeline lateral expansion project. Capital expenditures for Four Corners and Conway totaled $31.8 million, $31.3 million and $15.6 million in 2006, 2005 and 2004, respectively.

Net cash provided by financing activities in 2006 includes:

- $625.3 million of net proceeds from debt and equity issuances related to our acquisition of Four Corners less the related amounts distributed to Williams in excess of Four Corners contributed basis;
- distributions to unitholders and our general partner of $30.0 million; and
- contributions from our general partner to maintain their 2% ownership following the issuances of equity and per the omnibus agreement that totaled $25.5 million.

Net cash provided by financing activities in 2005 includes the cash flows related to our IPO in August 2005. In addition, 2006, 2005 and 2004 included $114.5 million, $187.2 million and $120.5 million, respectively, related to the pass through of net cash flows to Williams under its cash management program of Four Corners net cash flows and operations prior to our IPO.

Discovery 100%

	2006	2005	2004
		(In thousands)	
Net cash provided by operating activities	$ 62,606	$ 30,814	$ 35,623
Net cash used by investing activities	(16,312)	(65,997)	(39,115)
Net cash provided (used) by financing activities	(30,089)	1,339	

Net cash provided by operating activities increased $31.8 million in 2006 as compared to 2005 due primarily to an increase of $19.3 million in working capital and an increase of $10.0 million in operating income as adjusted for non-cash items. The 2006 cash provided related to working capital was due to receipts on invoices that were outstanding at the end of 2005 and the collection of hurricane-related insurance receivables. Net cash provided by operating activities decreased $4.8 million in 2005 as compared to 2004 due primarily to expenditures incurred for repairs following Hurricane Katrina that had not yet been reimbursed by Discovery s insurance carrier.

Net cash used by investing activities included $33.4 million of capital spending in 2006, primarily for the Tahiti project, partially offset by the use of $15.8 million of Tahiti-related restricted cash. During 2005, net cash used by investing activities included $44.6 million to fund escrow accounts for the Tahiti pipeline lateral project and related interest income and $21.4 million of capital expenditures for (1) the completion of the Front Runner and market expansion projects, (2) the initial expenditures for the Tahiti project, and (3) the purchase of leased compressors at the Larose processing plant. During 2004, net cash used by investing activities was primarily used for the construction of a gathering lateral to connect our pipeline system to the Front Runner prospect.

Net cash used by financing activities in 2006 includes $13.5 million of capital contributions compared to $48.3 million in 2005. Both years contributions related to the Tahiti pipeline lateral expansion. Additionally, Discovery distributed $41.0 million to its members during 2006. During 2005, Discovery distributed $43.8 million associated with its operations prior to our IPO and a $3.2 million quarterly distribution to members in the fourth quarter of 2005.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2006, is as follows (in thousands):

	2007	2008-2009	2010-2011	2012+	Total
Long-term debt:					
Principal	$	$	$ 150,000	$ 600,000	$ 750,000
Interest	36,625	109,500	109,500	239,250	494,875
Capital leases					
Operating leases	2,426	4,025	2,440	1,000	9,891
Purchase obligations	20,212(a)	240	240	120(b)	20,812
Other long term liabilities					
Total	$ 59,263	$ 113,765	$ 262,180	$ 840,370	$ 1,275,578

(a) Includes the open purchase orders as of 12/31/06 to be paid in 2007.

(b) Year 2012 represents one year of payments associated with an operating agreement whose term is tied to the life of the underlying gas reserves.

Our equity investee, Discovery, also has contractual obligations for which we are not contractually liable. These contractual obligations, however, will impact Discovery s ability to make cash distributions to us. A summary of Discovery s total contractual obligations as of December 31, 2006, is as follows (in thousands):

	2007	2008-2009	2010-2011	2012+	Total
Notes payable/long-term debt	$	$	$	$	$
Capital leases					
Operating leases	855	1,715	1,715	3,252	7,537
Purchase obligations(a)	33,279				33,279
Other long-term liabilities					
Total	$ 34,134	$ 1,715	$ 1,715	$ 3,252	$ 40,816

(a)

A majority of the amounts are Tahiti-related expenditures that will be funded from the amounts that were escrowed for this project in September 2005 and capital contributions from members including us. Please read Financial Condition and Liquidity .

Effects of Inflation

We have experienced increased costs in recent years due to the effects of growth in the oil and gas industry, which has increased competition for resources. Approximately 50% of Four Corners gathering and processing revenues are from contracts that include escalation clauses that provide for an annual escalation based on an inflation-sensitive index. These escalations, combined with increased fees where competition permits for new and amended contracts, help to offset these inflationary pressures; however, they may not always approximate the actual inflation rate we experience due to geographic and/or industry-specific inflationary pressures on our costs and expenses. We have significant annual capital expenditures related to well connections and gathering system expansions necessary to connect new sources of throughput to the Four Corners system as throughput volumes from existing wells will naturally decline over time.

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Regulatory Matters

Discovery s natural gas pipeline transportation is subject to rate regulation by the FERC under the Natural Gas Act. For more information on federal and state regulations affecting our business, please read Risk Factors and FERC Regulation elsewhere in this report.

Environmental

We are 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 seven 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 eight years. As of December 31, 2006, we had accrued liabilities totaling $0.7 million for these environmental activities. 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 and other factors. During 2006, we paid approximately $0.2 million in construction with these environmental activities.

Our Conway storage facilities are subject to strict environmental regulation by the Underground Storage Unit within the Geology Section of the Bureau of Water of the KDHE under the Underground Hydrocarbon and Natural Gas Storage Program, which became effective on April 1, 2003. We are in the process of modifying our Conway storage facilities, including the caverns and brine ponds, and we expect our storage operations will be in compliance with the Underground Hydrocarbon and Natural Gas Storage Program regulations by the applicable required 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 brine pond every other year. The incremental cost of these activities is approximately $5.5 million per year to complete the workovers and approximately $1.2 million per year to install a double liner on a brine bond. In response to these increased costs, we raised our storage rates by an amount sufficient to preserve our margins in this business. Accordingly, we do not believe that these increased costs have had a material effect on our business or results of operations. 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.

In 2004, we purchased an insurance policy that covers up to $5 million of remediation costs until an active remediation system is in place or April 30, 2008, whichever is earlier, excluding operation and maintenance costs and ongoing monitoring costs, for these projects to the extent such costs exceed a $4.2 million deductible, of which $0.7 million has been incurred to date from the onset of the policy. The policy also covers costs incurred as a result of third party claims associated with then existing but unknown contamination related to the storage facilities. The aggregate limit under the policy for all claims is $25 million. In addition, under an omnibus agreement with Williams entered into at the closing of the IPO, Williams has agreed to indemnify us for the $4.2 million deductible (less amounts expended prior to the closing of the IPO) of remediation expenditures not covered by the insurance policy, excluding costs of project management and soil and groundwater monitoring. There is a $14 million cap on the total amount of indemnity coverage under the omnibus agreement, which will be reduced by actual recoveries under the environmental insurance policy. There is also a three-year time limitation from the IPO closing date of August 23, 2005. We estimate that the approximate cost of this project management and soil and groundwater monitoring associated with the four remediation projects at the Conway storage facilities and for which we will not be indemnified will be approximately $0.2 million to $0.4 million per year following the completion of the remediation work. At December 31, 2006 and 2005, we had accrued liabilities totaling $5.9 million and $5.4 million, respectively, for these costs. 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.

In connection with our operations at the Conway facilities, we are required by the KDHE regulations to provide assurance of our financial capability to plug and abandon the wells and abandon the brine facilities we operate at Conway. Williams has posted two letters of credit on our behalf in an aggregate amount of

$18.0 million to guarantee our plugging and abandonment responsibilities for these facilities. We anticipate providing assurance in the form of letters of credit in future periods until such time as we obtain an investment-grade credit rating or are capable of meeting KDHE financial strength tests. After our filing of this Form 10-K, we will request the state to accept a financial test in lieu of the letters of credit.

In connection with the construction of Discovery s pipeline, approximately 73 acres of marshland was traversed. Discovery is required to restore marshland in other areas to offset the damage caused during the initial construction. In Phase I of this project, Discovery created new marshlands to replace about half of the traversed acreage. Phase II, which will complete the project, began during 2005 and will cost approximately $2.9 million.

Item 7A. *Qualitative and Quantitative 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

Certain of our and Discovery s processing contracts are exposed to the impact of price fluctuations in the commodity markets, including the correlation between natural gas and NGL prices. In addition, price fluctuations in commodity markets could impact the demand for our and Discovery s services in the future. Our Carbonate Trend pipeline and our fractionation and storage operations are not directly affected by changing commodity prices except for product imbalances, which are exposed to the impact of price fluctuation in NGL markets. Price fluctuations in commodity markets could also impact the demand for storage and fractionation services in the future. In connection with the IPO, 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. This physical contract is intended to mitigate the fuel price risk under one of our fractionation contracts which contains a cap on the per-unit fee that we can charge, at times limiting our ability to pass through the full amount of increases in variable expenses to that customer. This physical contract is a derivative. However, we elected to account for this contract under the normal purchases exemption to the fair value accounting that would otherwise apply. We also have physical contracts for the purchase of ethane and the sale of propane related to our operating supply management activities at Conway. These physical contracts are derivatives. However, we elected to account for these contracts under the normal purchases exemption to the fair value accounting that would otherwise apply. We and Discovery do not currently use any other derivatives to manage the risks associated with these price fluctuations.

Interest Rate Risk

Our long-term senior unsecured notes have fixed 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. As of December 31, 2006 we did not have borrowings under our credit agreements.

The table below provides information about our interest rate-sensitive instruments as of December 31, 2006. 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.

		Fair Value December 31,
	2011	**2006**

Long-term debt:		
Fixed rate	$ 150	$ 156
Interest rate	7.5%	
Fixed rate	$ 600	$ 612
Interest rate	7.25%	

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

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our general partner is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) and for the assessment of the effectiveness of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and board of directors regarding the preparation and fair presentation of financial statements in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and board of directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management assessed the effectiveness of Williams Partners L.P. s internal control over financial reporting as of December 31, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* Management s assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of our internal control over financial reporting. Based on our assessment we believe that, as of December 31, 2006, Williams Partners L.P. s internal control over financial reporting is effective based on those criteria.

Ernst & Young, LLP, our independent registered public accounting firm, has issued an audit report on our assessment of the company s internal control over financial reporting. A copy of this report is included in this Annual Report on Form 10-K.

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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 management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting, that Williams Partners L.P. maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that Williams Partners L.P. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also in our opinion, Williams Partners L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Williams Partners L.P. as of December 31, 2006 and 2005, and the related consolidated statements of income, partners capital, and cash flows for each of the three years in the period ended December 31, 2006, and our report dated February 22, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2007

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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, 2006 and 2005, and the related consolidated statements of income, partners capital, and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As described in Note 8**,** effective December 31, 2005, Williams Partners L.P. adopted Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations.*

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Williams Partners L.P. s internal control over financial reporting as of December 31, 2006, 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 22, 2007, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2007

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WILLIAMS PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005*
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 57,541	$ 6,839
Accounts receivable:		
Trade	18,320	17,695
Affiliate	12,420	
Other	3,991	3,472
Gas purchase contract affiliate	4,754	5,320
Prepaid expenses	3,765	2,742
Other current assets	2,534	
Total current assets	103,325	36,068
Investment in Discovery Producer Services	147,493	150,260
Property, plant and equipment, net	647,578	658,965
Gas purchase contract noncurrent affiliate		4,754
Other noncurrent assets	34,752	25,228
Total assets	$ 933,148	$ 875,275
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable:		
Trade	$ 19,827	$ 25,572
Affiliate		4,729
Product imbalance	651	1,765
Deferred revenue	3,382	3,552
Accrued liabilities	16,173	6,160
Total current liabilities	40,033	41,778
Long-term debt	750,000	
Environmental remediation liabilities	3,964	4,371
Other noncurrent liabilities	3,749	1,881
Commitments and contingent liabilities (Note 14)		
Partners capital:		
Common unitholders (25,553,306 and 7,006,146 outstanding at December 31, 2006 and 2005)	733,878	108,526
Class B unitholders (6,805,492 outstanding at December 31, 2006)	241,923	

Subordinated unitholders (7,000,000 outstanding at December 31, 2006 and 2005)	108,862	108,491
General partner	(949,261)	610,228
Total partners capital	135,402	827,245
Total liabilities and partners capital	$ 933,148	$ 875,275

* Restated as discussed in Note 1.

See accompanying notes to consolidated financial statements.

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WILLIAMS PARTNERS L.P.

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31, 2006	2005*	2004*
	(In thousands)		
Revenues:			
Gathering and processing:			
Affiliate	$ 42,228	$ 36,755	$ 30,990
Third-party	206,432	198,041	194,832
Product sales:			
Affiliate	255,075	236,020	199,716
Third-party	16,919	8,728	13,605
Storage	25,237	20,290	15,318
Fractionation	11,698	10,770	9,070
Other	5,821	4,368	5,668
Total revenues	563,410	514,972	469,199
Costs and expenses:			
Product cost and shrink replacement:			
Affiliate	78,201	58,780	58,193
Third-party	97,307	118,747	94,770
Operating and maintenance expense:			
Affiliate	53,627	46,194	39,968
Third-party	101,587	83,565	76,478
Depreciation, amortization and accretion	43,692	42,579	44,361
General and administrative expense:			
Affiliate	34,295	33,765	29,948
Third-party	5,145	2,850	2,231
Taxes other than income	8,961	8,446	7,506
Other (income) expense net	(2,473)	630	11,147
Total costs and expenses	420,342	395,556	364,602
Operating income	143,068	119,416	104,597
Equity earnings Discovery Producer Services	12,033	8,331	4,495
Impairment of investment in Discovery Producer Services			(13,484)
Interest expense:			
Affiliate	(89)	(7,461)	(11,980)
Third-party	(9,744)	(777)	(496)
Interest income	1,600	165	
Income before cumulative effect of change in accounting principle	146,868	119,674	83,132
Cumulative effect of change in accounting principle		(1,322)	

Net income	$ 146,868	$ 118,352	$ 83,132
Allocation of net income for calculation of earnings per unit:			
Net income	$ 146,868	$ 118,352	
Net income applicable to pre-partnership operations allocated to general partner	(116,450)	(113,418)	
Net income applicable to partnership operations	30,418	4,934	
Allocation of net loss to general partner	(2,897)	(1,273)	
Allocation of net income to limited partner	33,315	6,207	
Basic and diluted earnings per limited partner unit:			
Income before cumulative effect of change in accounting principle:			
Common units	$ 1.62	$ 0.49	
Class B units	$ 0.45	N/A	
Subordinated units	$ 1.62	$ 0.49	
Cumulative effect of change in accounting principle:			
Common units		$ (0.05)	
Class B units		N/A	
Subordinated units		$ (0.05)	
Net income:			
Common units	$ 1.62	$ 0.44	
Class B units	$ 0.45	N/A	
Subordinated units	$ 1.62	$ 0.44	
Weighted average number of units outstanding:			
Common units	11,632,110	7,001,366	
Class B units	354,258	N/A	
Subordinated units	7,000,000	7,000,000	

* Restated as discussed in Note 1.

See accompanying notes to consolidated financial statements.

WILLIAMS PARTNERS L.P.

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL*

	Limited Partners			Pre-IPO Owner s Equity/ General Partner	Total Partners Capital
	Common	Class B	Subordinated		
	(Dollars in thousands)				
Balance December 31, 2004	$	$	$	$ 637,198	$ 637,198
Accounts receivable not contributed				(2,640)	(2,640)
Contribution of net assets of predecessor companies (2,000,000 common units; 7,000,000 subordinated units)	10,471		106,427	49,174	166,072
Net income 2005	3,104		3,103	112,145	118,352
Cash distributions	(1,039)		(1,039)	(42)	(2,120)
Issuance of units to public (5,000,000 common units)	100,247				100,247
Offering costs	(4,291)				(4,291)
Issuance of common units (6,146 common units)	34				34
Distributions to The Williams Companies, Inc. net				(187,217)	(187,217)
Contributions pursuant to the omnibus agreement				1,610	1,610
Balance December 31, 2005	108,526		108,491	610,228	827,245
Net income 2006	21,181	655	11,606	113,426	146,868
Cash distributions	(17,887)		(11,235)	(872)	(29,994)
Issuance of units to public (18,545,030 common units)	625,995				625,995
Issuance of Class B units through Private placement (6,805,492 Class B units)		241,268			241,268
Offering costs	(4,168)				(4,168)
Distributions to The Williams Companies, Inc. net				(114,497)	(114,497)
Distributions to general partner for purchase of Four Corners				(1,583,000)	(1,583,000)
Contributions pursuant to the omnibus agreement				6,840	6,840
Contributions from general partner				18,614	18,614
Other	231				231

Balance December 31, 2006	$ 733,878	$ 241,923	$ 108,862	$ (949,261)	$ 135,402

* Restated as discussed in Note 1.

See accompanying notes to consolidated financial statements.

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WILLIAMS PARTNERS L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2006	2005*	2004*
		(In thousands)	
OPERATING ACTIVITIES:			
Net income	$ 146,868	$ 118,352	$ 83,132
Adjustments to reconcile to cash provided by operations:			
Cumulative effect of change in accounting principle		1,322	
Depreciation, amortization and accretion	43,692	42,579	44,361
Provision for loss on property, plant and equipment		917	7,636
(Gain)/loss on sale of property, plant and equipment	(3,055)		1,258
Impairment of investment in Discovery Producer Services			13,484
Amortization of gas purchase contract affiliate	5,320	2,033	
Distributions in excess of /(undistributed) equity Earnings of Discovery Producer Services	4,367	(7,051)	(4,495)
Cash provided (used) by changes in assets and liabilities:			
Accounts receivable	(13,564)	(4,419)	1,559
Prepaid expenses	(1,023)	(463)	(362)
Other current assets	(920)		
Accounts payable	(10,600)	8,801	12,146
Product imbalance	(1,114)	8,243	(7,295)
Accrued liabilities	6,395	(4,008)	(5,464)
Deferred revenue	(170)	247	775
Other, including changes in noncurrent assets and liabilities	(2,379)	(8,621)	(9,645)
Net cash provided by operating activities	173,817	157,932	137,090
INVESTING ACTIVITIES:			
Purchase of Four Corners	(607,545)		
Capital expenditures	(32,270)	(31,266)	(15,603)
Change in accrued liabilities-capital expenditures	5,078		
Contribution to Discovery Producer Services	(1,600)	(24,400)	
Proceeds from sales of property, plant and equipment	7,757		149
Net cash used by investing activities	(628,580)	(55,666)	(15,454)
FINANCING ACTIVITIES:			
Proceeds from sales of common units	867,263	100,247	
Proceeds from debt issuances	750,000		
Excess purchase price over the contributed basis of Four Corners	(975,455)		
Payment of debt issuance costs	(13,138)		
Payment of equity offering costs	(4,168)	(4,291)	

Distributions to The Williams Companies, Inc.	(114,497)	(187,217)	(120,467)
Changes in advances from affiliates net		(3,656)	(1,169)
Distributions to unitholders and general partner	(29,994)	(2,120)	
General partner contributions	18,614		
Contributions per omnibus agreement	6,840	1,610	
Net cash provided (used) by financing activities	505,465	(95,427)	(121,636)
Increase in cash and cash equivalents	50,702	6,839	
Cash and cash equivalents at beginning of year	6,839		
Cash and cash equivalents at end of year	$ 57,541	$ 6,839	$

* Restated as discussed in Note 1.

See accompanying notes to consolidated financial statements.

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 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 Discovery Producer Services LLC (Discovery) in which we own a 40% interest. When we refer to Discovery by name, we are referring exclusively to its businesses and operations.

We are a Delaware limited partnership that was formed in February 2005, to acquire and own (1) a 40% interest in Discovery; (2) the Carbonate Trend gathering pipeline off the coast of Alabama; (3) three integrated natural gas liquids (NGL) product storage facilities near Conway, Kansas; and (4) a 50% undivided ownership interest in a fractionator near Conway, Kansas. Prior to the closing of our initial public offering (the IPO) in August 2005, the 40% interest in Discovery was held by Williams Energy, L.L.C. (Energy) and Williams Discovery Pipeline LLC; the Carbonate Trend gathering pipeline was held in Carbonate Trend Pipeline LLC (CTP), which was owned by Williams Mobile Bay Producers Services, L.L.C.; and the NGL product storage facilities and the interest in the fractionator were owned by Mid-Continent Fractionation and Storage, LLC (MCFS). All of these are wholly owned indirect subsidiaries of The Williams Companies, Inc. (collectively Williams). Williams Partners GP LLC, a Delaware limited liability company, was also formed in February 2005 to serve as our general partner. We also formed Williams Partners Operating LLC (OLLC), an operating limited liability company (wholly owned by us), through which all our activities are conducted.

Initial Public Offering and Related Transactions

On August 23, 2005, we completed our IPO of 5,000,000 common units representing limited partner interests in us at a price of $21.50 per unit. The proceeds of $100.2 million, net of the underwriters discount and a structuring fee totaling $7.3 million, were used to:

- distribute $58.8 million to Williams in part to reimburse Williams for capital expenditures relating to the assets contributed to us and for a gas purchase contract contributed to us;

- provide $24.4 million to make a capital contribution to Discovery to fund an escrow account required in connection with the Tahiti pipeline lateral expansion project;

- provide $12.7 million of additional working capital; and

- pay $4.3 million of expenses associated with the IPO and related formation transactions.

Concurrent with the closing of the IPO, the 40% interest in Discovery and all of the interests in CTP and MCFS were contributed to us by Williams subsidiaries in exchange for an aggregate of 2,000,000 common units and 7,000,000 subordinated units. The public, through the underwriters of the offering, contributed $107.5 million ($100.2 million net of the underwriters discount and a structuring fee) to us in exchange for 5,000,000 common units representing a 35% limited partner interest in us. Additionally, at the closing of the IPO, the underwriters fully exercised their option to purchase 750,000 common units from Williams subsidiaries at the IPO price of $21.50 per unit less the underwriters discount and a structuring fee.

Acquisition of Four Corners

On June 20, 2006, we acquired a 25.1% membership interest in Williams Four Corners LLC (Four Corners) pursuant to an agreement with Williams Energy Services, LLC (WES), Williams Field Services Group LLC (WFSG), Williams Field Services Company, LLC (WFSC) and OLLC for aggregate consideration of $360.0 million. Prior to closing, WFSC contributed to Four Corners its natural gas gathering, processing and treating assets in the San Juan Basin in New Mexico and Colorado. We financed this acquisition with a combination of equity and debt. On June 20, 2006, we issued 6,600,000 common units at a price of $31.25 per unit. Additionally, at the closing, the underwriters fully exercised their option to purchase

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

990,000 common units at a price of $31.25 per unit. This offering yielded net proceeds of $227.1 million after payment of underwriting discounts and commissions of $10.1 million but before the payment of other offering expenses. On June 20, 2006, we also issued $150.0 million aggregate principal of unsecured 7.5% senior notes due 2011 under a private placement debt agreement. Proceeds from this issuance totaled $146.8 million (net of $3.2 million of related expenses).

On December 13, 2006, we acquired the remaining 74.9% membership interest in Four Corners pursuant to an agreement with WES, WFSG, WFSC and OLLC for aggregate consideration of $1.223 billion. We financed this acquisition with a combination of equity and debt. On December 13, 2006, we issued 7,000,000 common units at a price of $38.00. Additionally, at the closing, the underwriters fully exercised their option to purchase 1,050,000 common units at a price of $38.00 per unit. This offering yielded net proceeds of $293.7 million after payment of underwriting discounts and commissions of $12.2 million but before the payment of other offering expenses. On December 13, 2006, we received $346.5 million in proceeds from the sale of 2,905,030 common units and 6,805,492 unregistered Class B units in a private placement net of $3.5 million in placement agency fees. On December 13, 2006, we also issued $600.0 million aggregate principal of unsecured 7.25% senior notes due 2017 under a private placement debt agreement. Proceeds from this issuance totaled $590.0 million (net of $10.0 million of related expenses).

Because Four Corners was an affiliate of Williams at the time of these acquisitions, these transactions are accounted for as a combination of entities under common control, similar to a pooling of interests, whereby the assets and liabilities of Four Corners are combined with Williams Partners L.P. at their historical amounts for all periods presented. These two acquisitions of a combined 100% membership interest in Four Corners increased net income $113.5 million and $96.6 million for 2005 and 2004, respectively. The restatement to reflect these acquisitions does not impact historical earnings per unit as pre-acquisition earnings were allocated to our general partner.

Note 2. Description of Business

We are principally engaged in the business of gathering, transporting, processing and treating natural gas and fractionating and storing NGLs. 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. 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) a 3,500-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 760 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 treating capacity of 750 MMcf/d.

Gathering and Processing-Gulf . We own a 40% interest in Discovery, which includes a wholly-owned subsidiary, Discovery Gas Transmission LLC. Discovery owns (1) a 283-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 barrels per day (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

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 20 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. Williams operates 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.

Note 3. 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 subsidiaries. Intercompany accounts and transactions have been eliminated.

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;
- 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.

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash and Cash Equivalents. Cash and cash equivalents include demand and time deposits, certificates of deposit and other marketable securities with 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. No allowance for doubtful accounts is recognized 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. 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 unsuccessful.

Gas purchase contract. In connection with the IPO, 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. The gas purchase contract is for the purchase of 80,000 MMBtu per month and terminates on December 31, 2007. The initial value of this contract is being amortized to expense over the contract life.

Investments. We account for our investment in Discovery under the equity method since we do not control it. In 2004, we recognized an other-than-temporary impairment of our investment. As a result, Discovery s underlying equity exceeds the carrying value of our investment at December 31, 2006 and 2005.

Property, Plant and Equipment. Property, plant and equipment is recorded at cost. We base the carrying value of these assets on 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. 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 Consolidated 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 a corresponding accretion expense.

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. Land and right-of-way lease payments made at the time of initial construction or placement of plant and equipment on leased land are capitalized 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.

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. The sum of these items is reflected as product imbalance receivables or payables on the Consolidated Balance Sheets. These product imbalances are valued based on the market value of the products when the imbalance is identified and are evaluated for the impact of changes in market prices at the balance sheet date.

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WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revenue Recognition. The nature of our businesses result in various forms of revenue recognition. Our Gathering and Processing segments recognize (1) revenue 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 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. The impairment evaluation of tangible long-lived assets is measured pursuant to the guidelines of Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. 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 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. Environmental contingencies are recorded independently of any potential claim for recovery.

Capitalized Interest. We capitalize interest on major projects during construction to the extent we incur interest expense. Historically, Williams provided the financing for capital expenditures; hence, the rates used to calculate the interest were based on Williams average interest rate on debt during the applicable period in time. 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.

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Earnings Per Unit. In accordance with SFAS No. 128, Earnings Per Share, as clarified by the Emerging Issues Task Force (EITF) Issue 03-6, 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 2006, Williams adopted the fair value recognition provisions of FASB Statement No. 123(R), Share-Based Payment (SFAS No. 123(R)), using the modified-prospective method. Accordingly, payroll costs charged to us by our general partner reflect additional compensation costs related to the adoption of this accounting standard. These costs relate to Williams common stock equity awards made between Williams and its employees. The cost is charged to us through specific allocations of certain employees if they directly support our operations, and through an allocation methodology among all Williams affiliates if they provide indirect support. These allocated costs are based on a three-factor formula, which considers revenues; property, plant and equipment; and payroll. Our and Williams adoption of this Statement did not have a material impact on our Consolidated Financial Statements.

In January 2006 we adopted SFAS No. 151, Inventory Costs, an amendment of ARB No. 43, Chapter 4. The Statement amends Accounting Research Bulletin (ARB) No. 43, Chapter 4, Inventory Pricing, to clarify that abnormal amounts of certain costs should be recognized as current period charges and that the allocation of overhead costs should be based on the normal capacity of the production facility. The impact of this Statement on our Consolidated Financial Statements was not material.

In January 2006 we adopted SFAS No. 153, Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29. The Statement amends Accounting Principles Board (APB) Opinion No. 29, Accounting for Nonmonetary Transactions. The guidance in APB Opinion No. 29 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged but includes certain exceptions to that principle. SFAS No. 153 amends APB Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The impact of this Statement on our Consolidated Financial Statements was not material.

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements. This Statement establishes a framework for fair value measurements in the financial statements by providing a single definition of fair value, provides guidance on the methods used to estimate fair value and increases disclosures about estimates of fair value. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and is generally applied prospectively. We will assess the impact of this Statement on our Consolidated Financial Statements.

In December 2006, the FASB issued FASB Staff Position (FSP) EITF 00-19-2, Accounting for Registration Payment Arrangements. This FSP specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement should be separately recognized and measured in accordance with FASB Statement No. 5, Accounting for Contingencies. This FSP is effective immediately for registration payment arrangements and the financial instruments subject to those arrangements that are entered into or modified subsequent to December 21, 2006. For registration payment arrangements and financial instruments subject to those arrangements that were entered into prior to December 21, 2006, the guidance in the FSP is effective for fiscal years beginning after December 15, 2006. We do not expect this FSP to have a material impact on our Consolidated Financial Statements.

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 4. 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, 2006 and 2005 are as follows (in thousands):

	2006	2005
Allocation of net income to general partner:		
Net income	$ 146,868	$ 118,352
Net income applicable to pre-partnership operations allocated to general partner	(116,450)	(113,418)
Charges allocated directly to general partner:		
Reimbursable general and administrative costs	3,200	1,400
Core drilling indemnified costs	784	
Total charges allocated directly to general partner	3,984	1,400
Income subject to 2% allocation of general partner interest	34,402	6,334
General partner s share of net income	2.0%	2.0%
General partner s allocated share of net income before items directly allocable to general partner interest	688	127
Incentive distributions paid to general partner*	272	
Charges allocated directly to general partner	(3,984)	(1,400)
Pre-partnership net income allocated to general partner interest	116,450	113,418
Net income allocated to general partner	$ 113,426	$ 112,145
Net income	$ 146,868	$ 118,352
Net income allocated to general partner	113,426	112,145
Net income allocated to limited partners	$ 33,442	$ 6,207

* Under the two class method of computing earnings per share, prescribed by SFAS No. 128, Earnings Per Share, earnings are to be allocated to participating securities as if all of the earnings for the period had been distributed. As a result, the general partner receives an additional allocation of income in quarterly periods where an assumed incentive distribution, calculated as if all earnings for the period had been distributed, exceeds the actual incentive distribution. The assumed incentive distribution for the twelve months ended December 31, 2006 is $0.4 million. This results in an allocation of income for the calculation of earnings per limited partner unit as follows:

	2006	2005

Net income allocated to general partner	$ 113,553	$ 112,145
Net income allocated to limited partners	$ 33,315	$ 6,207
Net income	$ 146,868	$ 118,352

Pursuant to the partnership agreement, income allocations are made on a quarterly basis; therefore, earnings per limited partner unit for 2006 is calculated as the sum of the quarterly earnings per limited partner unit for each of the four quarters of 2006. Common, Class B and subordinated unitholders share equally, on a per-unit basis, in the net income allocated to limited partners.

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The reimbursable general and administrative and core drilling costs represent the costs charged against our income that are required to be reimbursed to us by our general partner under the terms of the omnibus agreement.

We paid or have authorized payment of the following cash distributions during 2005 and 2006 (in thousands, except for per unit amounts):

Payment Date	Per Unit Distribution	Common Units	Subordinated Units	Class B Units	General Partner	Total Cash Distribution
11/14/2005(a)	$ 0.1484	$ 1,039	$ 1,039		$ 42	$ 2,120
2/14/2006	$ 0.3500	$ 2,452	$ 2,450		$ 100	$ 5,002
5/15/2006	$ 0.3800	$ 2,662	$ 2,660		$ 109	$ 5,431
8/14/2006(b)	$ 0.4250	$ 6,204	$ 2,975		$ 263	$ 9,442
11/14/2006(c)	$ 0.4500	$ 6,569	$ 3,150		$ 401	$ 10,120
2/14/2007(d)	$ 0.4700	$ 12,010	$ 3,290	$ 3,198	$ 993	$ 19,491

(a) This distribution represents the $0.35 per unit minimum quarterly distribution pro-rated for the 39-day period following the IPO closing date (August 23, 2005 through September 30, 2005).

(b) Includes $0.1 million incentive distribution rights payment to the general partner.

(c) Includes $0.2 million incentive distribution rights payment to the general partner.

(d) On February 14, 2007, we paid a cash distribution of $0.47 per unit on our outstanding common, subordinated and Class B units to unitholders of record on February 7, 2007. This amount includes $0.6 million incentive distribution rights payment to the general partner.

Note 5. 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 and certain general and administrative 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. Certain of the payroll costs associated with the operations employees are charged back to the other Conway fractionator co-owners. Our share of those costs are 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 considered revenues; property, plant and equipment; and payroll. Certain of these costs are charged back to the other Conway fractionator co-owners. Our share of these costs 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 a capital contribution from our general partner. The annual amounts of the credits are as follows: $3.9 million in 2005 ($1.4 million pro-rated for the portion of the year from August 23 to December 31), $3.2 million in 2006, $2.4 million in 2007, $1.6 million in 2008 and $0.8 million in 2009.

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WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2006 and 2005 we have a contribution receivable from our general partner of $0.4 million and $0.3 million, respectively, which is netted against Partners capital on the Consolidated Balance Sheets, for amounts reimbursable to us under the omnibus agreement.

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 Power Company (Power), 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 made at market rates at the time of purchase. In connection with the IPO, 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. The amortization of this contract is reflected in Operating and maintenance expense Affiliate in the accompanying Consolidated Statements of Income. The carrying value of this contract is reflected as Gas purchase contract affiliate and Gas purchase contract noncurrent affiliate on the Consolidated Balance Sheets.

We purchase natural gas for delivery of waste heat from Power that we use to generate steam at our Milagro treating plant. The natural gas cost charged to us by Power has been favorably impacted by Power s fixed price natural gas fuel contracts. This impact was approximately $9.0 million annually during the periods presented as compared to estimated market prices. These agreements expired in the fourth quarter of 2006 and were replaced with new agreements. We expect that our Milagro natural gas fuel costs will increase due to our expectation that future market prices will exceed prices associated with the prior agreements.

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. These purchase and sales transactions are conducted for us by Power, at current market prices at each location and are included in Product sales Affiliate and Product cost and shrink replacement Affiliate on the Consolidated Statements of Income. Historically, Power 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 Midstream Marketing and Risk Management, LLC (WMMRM), a wholly owned subsidiary of Williams. Revenues associated with these activities are reflected as Product sales Affiliate on the Consolidated Statements of Income. These transactions are conducted at current market prices for the products.

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. Revenues associated with these activities are reflected in the Gathering and processing Affiliate on the Consolidated Statements of Income.

In December 2004, we began selling Conway s surplus propane and other NGLs to Power, 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 Power to replenish deficit product inventory positions. The transactions conducted between us and Power are transacted at current market prices for the products.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the general and administrative expenses directly charged and allocated to us, fuel purchases from Power and NGL purchases from Power for the periods stated is as follows:

	2006	2005	2004
		(In thousands)	
General and administrative expenses, including amounts subsequently charged to co-owners:			
Allocated	$ 18,512	$ 29,400	$ 24,293
Directly charged	10,574	4,607	5,655
Operating and maintenance expenses, including amounts subsequently charged to co-owners:			
Fuel purchases, including amortization of gas contract	38,197	38,996	28,851
Salaries and benefits	26,860	21,812	21,657
NGL purchases	14,884	15,657	1,271

The per-unit gathering fee associated with two of our Carbonate Trend gathering contracts was negotiated on a bundled basis that includes transportation along a segment of a pipeline system owned by Transcontinental Gas Pipe Line Company (Transco), a wholly owned subsidiary of Williams. The fees we realize are dependent upon whether our customer elects to utilize this Transco capacity. When they make this election, our gathering fee is determined by subtracting the Transco tariff from the total negotiated fee. The rate associated with the capacity agreement is based on a Federal Energy Regulatory Commission tariff that is subject to change. Accordingly, if the Transco rate increases, our net gathering fees for these two contracts may be reduced. The customers with these bundled contracts must make an annual election to receive this capacity. For 2005 and 2006, only one of our customers elected to utilize this capacity.

Prior to its acquisition by us, Four Corners participated in Williams cash management program under an unsecured promissory note agreement with Williams for both advances to and from Williams. As of December 31, 2005 and 2004, Four Corners net advances to Williams were classified as a component of general partner s capital because Williams has not historically required repayment or repaid amounts owed us. In addition, upon Four Corners acquisition by us, the outstanding advances were distributed to Williams. Changes in these advances to Williams are presented as distributions to Williams in the Consolidated Statement of Partners Capital and Consolidated Statements of Cash Flows.

For 2005 and 2004, affiliate interest expense includes interest on the advances with Williams calculated using Williams weighted average cost of debt applied to the outstanding balance of the advances with Williams. For 2006 and 2005, affiliate interest expense also includes commitment fees on the working capital credit facility (see Note 11). The interest rate on the advances with Williams was 7.70% at December 31, 2005.

With the transition to a stand-alone cash management program, amounts owed by us or to us by Williams or its subsidiaries are shown as Accounts payable-Affiliate or Accounts receivable-Affiliate in the accompanying Consolidated Balance Sheets.

Note 6. Investment in Discovery Producer Services

Our 40% investment in Discovery is accounted for using the equity method of accounting since we do not control it. At December 31, 2006 and 2005, Williams owned an additional 20% ownership interest in Discovery through Energy.

In October, 2006 and September 2005, we made $1.6 million and $24.4 million capital contributions, respectively, to Discovery for a substantial portion of our share of the estimated future capital expenditures for the Tahiti pipeline lateral expansion project.

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WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Williams is the operator of Discovery. Discovery reimburses Williams for actual 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 Williams to meet its fuel and shrink replacement needs at its processing plant and (2) Williams purchases the NGLs and excess natural gas to which Discovery takes title.

During 2004, we performed an impairment review of this investment because of Williams planned purchase of an additional interest in Discovery at an amount below its carrying value. As a result, we recorded a $13.5 million impairment of our investment in Discovery based on a probability-weighted estimation of fair value of our investment.

During 2006 and 2005 we received total distributions of $16.4 million and $1.3 million, respectively, from Discovery.

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

	December 31, 2006	December 31, 2005
Current assets	$ 73,841	$ 70,525
Non-current restricted cash	28,773	44,559
Property, plant and equipment	355,304	344,743
Current liabilities	(40,559)	(45,070)
Non-current liabilities	(3,728)	(1,121)
Members capital	$ 413,631	$ 413,636

	Years Ended December 31, 2006	2005	2004
Revenues:			
Affiliate	$ 160,825	$ 76,864	$ 68,766
Third-party	36,488	45,881	31,110
Costs and expenses:			
Affiliate	74,316	24,895	4,945
Third-party	97,394	77,702	83,811
Interest income	(2,404)	(1,685)	(550)
Foreign exchange (gain) loss	(2,076)	1,005	
Income before cumulative effect of change in accounting principle	$ 30,083	$ 20,828	$ 11,670

Net income	$ 30,083	$ 20,652	$ 11,670

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WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 7. Other Costs and Expenses Net

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

	Years Ended December 31, 2006	2005	2004
Impairment of LaMaquina carbon dioxide treating facility	$	$	$ 7,636
Gain on sale of LaMaquina carbon dioxide treating facility	(3,619)		
Other	1,146	630	3,511
Total	$ (2,473)	$ 630	$ 11,147

LaMaquina Carbon Dioxide Treating Facility. This Four Corners facility consisted of two amine trains and seven gas powered generator sets. The facility was shut down in 2002 due to a reduced need for treating. In 2003, management estimated that only one amine train would be returned to service. As a result, we recognized an impairment of the carrying value of the other train to its estimated fair value based on estimated salvage values and sales prices. Further developments in 2004 led management to conclude that the facility would not return to service. Thus, we recognized an additional impairment of the carrying value to its estimated fair value. The facility was sold in the first quarter of 2006 resulting in the recognition of a gain on the sale in 2006.

Other. In 2004, other expense included losses from Four Corners asset dispositions and materials and supplies inventory adjustments.

Note 8. Property, Plant and Equipment

Property, plant and equipment, at cost, is as follows:

	December 31, 2006 (In thousands)	December 31, 2005 (In thousands)	Estimated Depreciable Lives
Land and right of way	$ 41,721	$ 44,363	
Gathering pipelines and related equipment	821,478	801,385	20-30 years
Processing plants and related equipment	147,241	164,257	30 years
Fractionation plant and related equipment	16,697	16,646	30 years
Storage plant and related equipment	69,017	65,892	30 years
Buildings and other equipment	90,082	90,070	3-45 years
Construction work in progress	19,447	20,323	

Total property, plant and equipment	1,205,683	1,202,936
Accumulated depreciation	558,105	543,971
Net property, plant and equipment	$ 647,578	$ 658,965

Effective December 31, 2005, we adopted FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. This Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO when incurred if the liability s fair value can be reasonably estimated. The Interpretation clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. As required by the new standard, we reassessed the estimated remaining life of all our assets with a conditional ARO. We recorded additional liabilities totaling $1.4 million equal to the present value of expected future asset retirement obligations at December 31, 2005. The liabilities are slightly offset

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

by a $0.1 million increase in property, plant and equipment, net of accumulated depreciation, recorded as if the provisions of the Interpretation had been in effect at the date the obligation was incurred. The net $1.3 million reduction to earnings is reflected as a cumulative effect of a change in accounting principle for the year ended 2005. An additional $0.1 million reduction of earnings is reflected as a cumulative effect of a change in accounting principle for our 40% interest in Discovery s cumulative effect of a change in accounting principle related to the adoption of FIN No. 47. If the Interpretation had been in effect at the beginning of 2004, the impact to our income from continuing operations and net income would have been immaterial.

The 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. 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, empty the brine ponds and restore the surface, and remove any related surface equipment.

A rollforward of our asset retirement obligation for 2006 and 2005 is presented below.

	2006	2005
	(In thousands)	
Balance, January 1	$ 1,880	$ 1,090
Liabilities incurred during the period		91
Liabilities settled during the period	(510)	(204)
Accretion expense	86	1
Estimate revisions	2,943	(460)
FIN No. 47 revisions		1,362
Loss on settlements	77	
Balance, December 31	$ 4,476	$ 1,880

Note 9. Accrued Liabilities

Accrued liabilities are as follows:

	December 31,	
	2006	2005
	(In thousands)	
Environmental remediation current portion	$ 2,636	$ 1,752
Customer deposit for construction	5,078	
Accrued interest	2,796	
Taxes other than income	2,347	2,431

Other	3,316	1,977
	$ 16,173	$ 6,160

Note 10. Major Customers, Concentrations of Credit Risk and Financial Instruments

Major customers

Our largest customer, on a percentage of revenues basis, is WMMRM, which purchases and resells substantially all of the NGLs to which we take title. WMMRM accounted for 43%, 46% and 42% of revenues

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

in 2006, 2005 and 2004, respectively. The percentages for the remaining two largest customers, both from our Gathering and Processing West segment, are as follows:

	2006	2005	2004
ConocoPhillips	12%	14%	14%
Burlington Resources	9	10	11

Burlington Resources was acquired by ConocoPhillips on March 31, 2006.

Concentrations of Credit Risk

Our cash equivalents consist of high-quality securities placed with various major financial institutions with credit ratings at or above AA by Standard & Poor s or Aa by Moody s Investor s Service.

The following table summarizes the concentration of accounts receivable by service and segment.

	December 31,	
	2006	2005
	(In thousands)	
Gathering and Processing West:		
Natural gas gathering and processing	$ 16,709	$ 15,855
Other	561	1,368
Gathering and Processing Gulf:		
Natural gas gathering	468	525
Other	1,343	
NGL Services:		
Fractionation services	320	532
Amounts due from fractionator partners	1,833	1,834
Storage	825	793
Other	36	260
Accrued interest	216	
	$ 22,311	$ 21,167

For the years ended December 31, 2006 and 2005, a substantial portion of our accounts receivable result from product sales and gathering and processing services provided to four of our 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 conditions and credit worthiness are evaluated regularly. Our credit policy and the relatively short duration of receivables mitigate the risk of uncollectible receivables.

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.

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-term debt. The fair value of our private long-term debt is based on the prices of similar securities with similar terms and credit ratings.

	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Cash and cash equivalents	$ 57,541	$ 57,541	$ 6,839	$ 6,839
Long-term debt (see Note 11)	$ 750,000	$ 768,844		

Note 11. Long-Term Debt, Credit Facilities and Leasing Activities

Long-Term Debt

On December 13, 2006, we and Williams Partners Finance Corporation issued $600.0 million aggregate principal of 7.25% senior unsecured notes in a private debt placement. Williams Partners Finance Corporation is our wholly owned subsidiary organized for the sole purpose of co-issuing our debt securities. The maturity date of the notes is February 1, 2017. Interest is payable semi-annually in arrears on February 1 and August 1 of each year, beginning on August 1, 2007. Debt issuance costs associated with the notes totaled $10.0 million and are being amortized over the life of the notes.

On June 20, 2006, we and Williams Partners Finance Corporation issued $150.0 million aggregate principal of 7.5% senior unsecured notes in a private debt placement. The maturity date of the notes is June 15, 2011. Interest is payable semi-annually in arrears on June 15 and December 15 of each year, with the first payment due on December 15, 2006. Debt issuance costs associated with the notes totaled $3.1 million and are being amortized over the life of the notes.

In connection with the issuance of the $600.0 million and $150.0 million senior unsecured notes, sold in private debt placements to qualified institutional buyers in accordance with Rule 144A under the Securities Act and outside the United States in accordance with Regulations under the Securities Act, we entered into registration rights agreements with the initial purchasers of the senior unsecured notes whereby we agreed to conduct a registered exchange offer of exchange notes in exchange for the senior unsecured notes or cause to become effective a shelf registration statement providing for resale of the senior unsecured notes. If we fail to file a registration statement with the SEC within 270 days of the respective closing dates, we will be required to pay liquidated damages in the form of additional cash interest to the holders of the senior unsecured notes. Upon the occurrence of such a failure to comply, the interest rate on the senior unsecured notes shall be increased by 0.25% per annum during the 90-day period immediately following the occurrence of such failure to comply and shall increase by 0.25% per annum 90 days thereafter until all defaults have been cured, but in no event shall such aggregate additional interest exceed 0.50% per annum.

The terms of the senior unsecured notes are governed by an indenture that contains affirmative and negative covenants that, among other things, limit (1) our ability and the ability of our subsidiaries to incur liens securing indebtedness,

(2) mergers, consolidations and transfers of all or substantially all of our properties or assets, (3) Williams Partners Finance Corporation s ability to incur additional indebtedness and (4) Williams Partners Finance Corporation s ability to engage in any business not related to obtaining money or arranging financing for us or our other subsidiaries. Our investment in Discovery will not be classified as our subsidiary under the indenture so long as we continue to own a minority interest in such entity. As a result, Discovery will not be subject to the restrictive covenants in the indenture. The indenture also contains 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 $600.0 million senior unsecured notes and the $150.0 million senior unsecured notes at our option in whole or in part at any time or from time to time prior to February 1, 2017 and June 15,

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2011, respectively, 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.

Pursuant to the indenture, we may issue additional notes from time to time. The senior notes and any additional notes subsequently issued under the indenture, together with any exchange notes, will be treated as a single class for all purposes under the indenture, including, without limitation, waivers, amendments, redemptions and offers to purchase.

The senior notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to all of our future indebtedness that is expressly subordinated in right of payment to the senior notes. The senior notes will not initially be guaranteed by any of our subsidiaries. In the future in certain instances as set forth in the indenture, one or more of our subsidiaries may be required to guarantee the senior notes.

Cash payments for interest for 2006 and 2005 were $5.5 million and $0.3 million, respectively.

Credit Facilities

In May 2006, Williams replaced its $1.275 billion secured credit facility with a $1.5 billion unsecured credit facility (Williams facility). The new facility, which also allows us to borrow up to $75.0 million, contains substantially similar terms and covenants as the prior facility, but contains additional restrictions on asset sales, certain subsidiary debt and sale-leaseback transactions. Borrowings under the Williams facility mature in May 2009. Our $75.0 million borrowing limit under the Williams facility is available for general partnership purposes, including acquisitions, but only to the extent that sufficient amounts remain unborrowed by Williams and its other subsidiaries. Letters of credit totaling $29.0 million at December 31, 2006 had been issued on behalf of Williams by the participating institutions under the Williams facility and no revolving credit loans were outstanding.

Interest on any borrowings under the Williams facility is calculated based on our choice of two methods: (i) a fluctuating rate equal to the facilitating bank s base rate plus an applicable margin or (ii) a periodic fixed rate equal to LIBOR plus an applicable margin. We are also required to pay or reimburse Williams for a commitment fee based on the unused portion of our $75.0 million borrowing limit under the Williams facility, 0.25% at December 31, 2006 and 0.325% at December 31, 2005. The applicable margins, which were 1.25% at December 31, 2006 and 1.75% at December 31, 2005 related to LIBOR and 0.25% at December 31, 2006 and 0.75% at December 31, 2005 related to the facilitating bank s base rate, and the commitment fee are based on Williams senior unsecured long-term debt rating. Under the Williams facility, Williams and certain of its subsidiaries, other than us, are required to comply with certain financial and other covenants. Significant financial covenants under the Williams facility to which Williams is subject, and in compliance with, include the following:

ratio of debt to net worth no greater than 65%;

ratio of debt to net worth no greater than 55% for Northwest Pipeline Corporation, a wholly owned subsidiary of Williams, and Transco; and

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WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ratio of EBITDA to interest, on a rolling four quarter basis, no less than (i) 2.5 for any period through December 31, 2007 and (ii) 3.0 for the remaining term of the agreement.

On August 7, 2006 we amended and restated the $20.0 million revolving credit facility (the 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 June 20, 2009 and bear interest at the one-month LIBOR. We pay a commitment fee to Williams on the unused portion of the credit facility of 0.30% annually. We are required to reduce all borrowings under the credit facility to zero for a period of at least 15 consecutive days once each 12-month period prior to the maturity date of the credit facility. As of December 31, 2006, we have had no borrowings under the working capital credit facility.

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. The most significant of the Indian tribal leases will expire at the end of 2022 and will then be subject to renegotiation. Four Corners leases compression units under a lease agreement with Hanover Compression, Inc. The initial term of this agreement expired on June 30, 2006. We continue to lease these units on a month-to-month basis during the ongoing renegotiation. The month-to-month arrangement can be terminated by either party upon thirty days advance written notice. 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, 2006 are payable as follows:

		(In thousands)
2007		2,426
2008		2,188
2009		1,837
2010		1,410
2011 and thereafter		2,030
	$	9,891

Total rent expense was $19.4 million, $18.9 million and $14.8 million for 2006, 2005 and 2004, respectively.

Note 12. Partners Capital

Of the 25,553,306 common units outstanding at December 31, 2006, 21,398,276 are held by the public, 2,905,030 are privately held, and the remaining 1,250,000 held by our affiliates. The 6,805,492 Class B units outstanding at December 31, 2006 are privately held. All of the 7,000,000 subordinated units are held by our affiliates.

Description of Class B Units

The Class B units are subordinated to common units and senior to subordinated units with respect to the payment of the minimum quarterly distribution, including any arrearages with respect to minimum quarterly distributions from prior periods. The Class B units are subordinated to common units and senior to subordinated units with respect to the right to receive distributions upon our liquidation.

The Class B units will convert into common units on a one-for-one basis upon the approval of a majority of the votes cast by common unitholders provided that the total number of votes cast is at least a majority of common units eligible to vote (excluding common units held by Williams). We are required to seek such approval as promptly as practicable after issuance of the Class B units and not later than June 11, 2007. If the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

requisite approval is not obtained, we will be obligated to resubmit the conversion proposal to holders of our common units, but not more frequently than once every six months. If we have not obtained the requisite unitholder approval of the conversion of the Class B units by June 11, 2007, the Class B units will be entitled to receive 115% of the quarterly distribution and distributions on liquidation payable on each common unit, subject to the subordination provisions described above.

The Class B units have the same voting rights as our outstanding common units and are entitled to vote as a separate class on any matters that adversely affect the rights or preferences of the Class B units in relation to other classes of partnership interests or as required by law. The Class B units are not entitled to vote on the approval of the conversion of the Class B units into common units.

Subordinated Units

Upon expiration of the subordination period, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. The subordination period will end on the first day of any quarter beginning after June 30, 2008 or when we meet certain financial tests provided for in our partnership agreement.

Limited Partners Rights

Significant information regarding rights of the limited partners includes 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 power 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 662/3% of the outstanding units voting as a single class, including units held by our general partner and its affiliates.
- Right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year.

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 the event of a 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 13. Long-Term Incentive Plan

In November 2005, our general partner adopted 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. The Plan permits the grant of awards covering an aggregate of 700,000 common units. These awards may be in the form of options, restricted units, phantom units or unit appreciation rights.

During 2006 and 2005, our general partner granted 2,130 and 6,146 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 six months from grant date. We recognized compensation expense of $229,000 and $34,000 associated with these awards in 2006 and 2005, respectively.

Note 14. Commitments and Contingencies

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 seven 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 eight years.

We have accrued liabilities totaling $0.7 million at December 31, 2006 and December 31, 2005 for these environmental activities. It is reasonably possible that we will incur costs 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 and other factors.

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 applicable environmental laws and regulations.

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 next two to nine years.

In 2004, we purchased an insurance policy that covers up to $5.0 million of remediation costs until an active remediation system is in place or April 30, 2008, whichever is earlier, excluding operation and maintenance costs and ongoing monitoring costs, for these projects to the extent such costs exceed a $4.2 million deductible, of which $0.7 million has been incurred to date from the onset of the policy. The policy also covers costs incurred as a result of third party claims associated with then existing but unknown

WILLIAMS PARTNERS L. P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

contamination related to the storage facilities. The aggregate limit under the policy for all claims is $25.0 million. In addition, under an omnibus agreement with Williams entered into at the closing of the IPO, Williams has agreed to indemnify us for the $4.2 million deductible not covered by the insurance policy, excluding costs of project management and soil and groundwater monitoring. There is a $14.0 million cap on the total amount of indemnity coverage under the omnibus agreement, which will be reduced by actual recoveries under the environmental insurance policy. There is also a three-year time limitation from the August 23, 2005 IPO closing date. The benefit of this indemnification will be accounted for as a capital contribution to us by Williams as the costs are reimbursed. We estimate that the approximate cost of this project management and soil and groundwater monitoring associated with the four remediation projects at the Conway storage facilities and for which we will not be indemnified will be approximately $0.2 million to $0.4 million per year following the completion of the remediation work. At December 31, 2006 and 2005, we had accrued liabilities totaling $5.9 million and $5.4 million, respectively, 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 any excess 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.

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 a hearing on plaintiffs second motion to certify the class was held on April 1, 2005. We are awaiting a decision from the court.

Grynberg. In 1998, the Department of Justice informed Williams that Jack Grynberg, an individual, had filed claims on behalf of himself and the federal government, in the United States District Court for the District of Colorado under the False Claims Act against Williams and certain of its wholly owned subsidiaries, including us. The claims sought an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys fees, and costs. Grynberg has also filed claims against approximately 300 other energy companies alleging that the defendants violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. In 1999, the Department of Justice announced that it was declining to intervene in any of the Grynberg cases, including the action filed in federal court in Colorado against us. Also in 1999, the Panel on Multi-District Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg s measurement claims remain pending against us and the other defendants; the court previously dismissed Grynberg s royalty valuation claims. In May 2005, the court-appointed special master entered a report which recommended that the claims against certain Williams subsidiaries, including us, be dismissed. On October 20, 2006, the court dismissed all claims against us. In November 2006, Grynberg filed his notice of appeals with the Tenth Circuit Court of Appeals.

Vendor Dispute. We are parties to an agreement with a service provider for work on turbines at our Ignacio, New Mexico plant. A dispute has arisen between us as to the quality of the service provider s work and the appropriate compensation. The service provider claims it is entitled to additional extra work charges under the agreement, which we deny are due.

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,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a materially adverse effect upon our future financial position.

Note 15. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different industry knowledge, technology and marketing strategies. The accounting policies of the segments are the same as those described in Note 3, 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)		
2006				
Segment revenues:				
Product sales	$ 255,907	$	$ 16,087	$ 271,994
Gathering and processing	246,004	2,656		248,660
Storage			25,237	25,237
Fractionation			11,698	11,698
Other	402		5,419	5,821
Total revenues	502,313	2,656	58,441	563,410
Product cost and shrink replacement	159,997		15,511	175,508
Operating and maintenance expense	124,763	1,660	28,791	155,214
Depreciation, amortization and accretion	40,055	1,200	2,437	43,692
Direct general and administrative expenses	11,920	1	1,149	13,070
Other, net	5,769		719	6,488
Segment operating income (loss)	159,809	(205)	9,834	169,438
Equity earnings		12,033		12,033
Segment profit	$ 159,809	$ 11,828	$ 9,834	$ 181,471
Reconciliation to the Consolidated Statement of Income:				
Segment operating income				$ 169,438
General and administrative expenses:				
Allocated affiliate				(23,721)

Third-party direct				(2,649)
Combined operating income				$ 143,068
Other financial information:				
Segment assets	$ 653,949	$ 207,390	$ 76,502	$ 937,841
Other assets and eliminations				(4,693)
Total assets				$ 933,148
Equity method investments	$	$ 147,493	$	$ 147,493
Additions to long-lived assets	25,889		6,381	32,270

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Gathering & Processing - West	Gathering & Processing - Gulf	NGL Services	Total
	(In thousands)			
2005				
Segment revenues:				
Product sales	$ 231,285	$	$ 13,463	$ 244,748
Gathering and processing	231,733	3,063		234,796
Storage			20,290	20,290
Fractionation			10,770	10,770
Other	185	452	3,731	4,368
Total revenues	463,203	3,515	48,254	514,972
Product cost and shrink replacement	165,706		11,821	177,527
Operating and maintenance expense	104,648	714	24,397	129,759
Depreciation, amortization and accretion	38,960	1,200	2,419	42,579
Direct general and administrative expenses	12,230	2	1,068	13,300
Other, net	8,382		694	9,076
Segment operating income	133,277	1,599	7,855	142,731
Equity earnings		8,331		8,331
Segment profit	$ 133,277	$ 9,930	$ 7,855	$ 151,062
Reconciliation to the Consolidated Statement of Income:				
Segment operating income				$ 142,731
General and administrative expenses:				
Allocated affiliate				(22,256)
Third-party direct				(1,059)
Combined operating income				$ 119,416
Other financial information:				
Segment assets	$ 635,094	$ 171,009	$ 63,819	$ 869,922
Other assets and eliminations				5,353
Total assets				$ 875,275
Equity method investments	$	$ 150,260	$	$ 150,260

Additions to long-lived assets	27,578	3,688	31,266

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Gathering & Processing - West	Gathering & Processing - Gulf	NGL Services	Total
		(In thousands)		
2004				
Segment revenues:				
Product sales	$ 204,868	$	$ 8,453	$ 213,321
Gathering and processing	221,939	3,883		225,822
Storage			15,318	15,318
Fractionation			9,070	9,070
Other	1,416	950	3,302	5,668
Total revenues	428,223	4,833	36,143	469,199
Product cost and shrink replacement	146,328		6,635	152,963
Operating and maintenance expense	97,070	572	18,804	116,446
Depreciation, amortization and accretion	40,675	1,200	2,486	44,361
Direct general and administrative expenses	8,500		535	9,035
Other, net	18,028		625	18,653
Segment operating income	117,622	3,061	7,058	127,741
Equity earnings		4,495		4,495
Impairment of investment		(13,484)		(13,484)
Segment profit (loss)	$ 117,622	$ (5,928)	$ 7,058	$ 118,752
Reconciliation to the Consolidated Statement of Income:				
Segment operating income				$ 127,741
Allocated general and administrative expenses				(23,144)
Combined operating income				$ 104,597
Other financial information:				
Total assets	$ 645,294	$ 166,985	$ 51,305	$ 863,584
Equity method investments		147,281		147,281
Additions to long-lived assets	14,069		1,622	15,691

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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
2006				
Revenues	132,735	141,186	146,582	142,907
Costs and operating expenses	98,726	109,401	104,424	107,791
Net income	37,624	33,594	43,404	32,246
Basic and diluted net income per limited partner unit:				
Income before cumulative effect of change in accounting principle:				
Common units	$ 0.35	$ 0.25	$ 0.57	$ 0.45
Class B units	$	$	$	$ 0.45
Subordinated units	$ 0.35	$ 0.25	$ 0.57	$ 0.45
Net income:				
Common units	$ 0.35	$ 0.25	$ 0.57	$ 0.45
Class B units	$	$	$	$ 0.45
Subordinated units	$ 0.35	$ 0.25	$ 0.57	$ 0.45

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2005				
Revenues	$ 119,272	$ 120,256	$ 132,340	$ 143,104
Costs and operating expenses	92,274	89,301	99,216	114,765
Income before cumulative effect of change in accounting principle	26,206	28,664	31,252	33,552
Net income	26,206	28,664	31,252	32,230
Basic and diluted net income (loss) per limited partner unit:				
Income (loss) before cumulative effect of change in accounting principle:				
Common units	NA	NA	$ (0.02)	$ 0.51
Subordinated units	NA	NA	$ (0.02)	$ 0.51
Cumulative effect of change in accounting principle:				
Common units	NA	NA	$	$ (0.05)
Subordinated units	NA	NA	$	$ (0.05)
Net income (loss):				
Common units	NA	NA	$ (0.02)	$ 0.46
Subordinated units	NA	NA	$ (0.02)	$ 0.46

Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15(d) (e) of the Securities Exchange Act) (Disclosure Controls) was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our general partner s 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.

Our management, including our general partner s chief executive officer and chief financial officer, does not expect that our Disclosure Controls or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and the Internal Controls will be modified as systems change and conditions warrant.

Changes in Internal Controls Over Financial Reporting

There have been no changes during the fourth quarter of 2006 that have materially affected, or are reasonably likely to materially affect, our Internal Controls over financial reporting.

Management s Report on Internal Control over Financial Reporting

See Management s Report on Internal Control over Financial Reporting set forth above in Item 8, Financial Statements and Supplementary Data.

Item 9B. *Other Information*

There have been no events that occurred in the fourth quarter of 2006 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.

We are managed and operated by the directors and officers of our general partner. All of our operational personnel are employees of an affiliate of our general partner.

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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. Alan Armstrong, the chief operating officer of our general partner, is the principal executive responsible for the oversight of our affairs. Our non-executive directors will 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 26, 2007.

Name	Age	Position with Williams Partners GP LLC
Steven J. Malcolm	58	Chairman of the Board and Chief Executive Officer
Donald R. Chappel	55	Chief Financial Officer and Director
Alan S. Armstrong	44	Chief Operating Officer and Director
James J. Bender	50	General Counsel
Thomas C. Knudson	60	Director and Member of Audit and Conflicts Committees
Bill Z. Parker	59	Director and Member of Audit and Conflicts Committees
Alice M. Peterson	54	Director and Member of Audit and Conflicts Committees
Phillip D. Wright	51	Director

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 of Williams since January 2002 and chairman of the board of directors of Williams since May 2002. From May 2001 to September 2001, he served as executive vice president of Williams. From December 1998 to May 2001, he served as president and chief executive officer of Williams Energy Services, LLC. From November 1994 to December 1998, Mr. Malcolm served as the senior vice president and general manager of Williams Field Services Company. Mr. Malcolm served as chief executive officer and chairman of the board of directors of the general partner of Williams Energy Partners L.P. (now known as Magellan Midstream Partners, L.P.) from its initial public offering in February 2001 to the sale of Williams interests therein in June 2003. Mr. Malcolm has served as a member of the board of directors of BOK Financial Corporation since 2002. Mr. Malcolm was named as a defendant in numerous shareholder class action suits that have been filed against Williams by Williams securities holders. These class actions include issues related to the spin-off of WilTel Communications, a previously-owned subsidiary of Williams, Williams Power Company, and public offerings in January 2001, August 2001 and January 2002, known as the FELINE PACS offering. Settlement of the Williams securities holders class action was approved by the court in February 2007. Additionally, four class action complaints were filed against Williams, certain committee members and certain members of the Williams board of directors, including Mr. Malcolm, under the Employee Retirement Income Security Act of 1974, or ERISA, by participants in Williams Investment Plus Plan. Final court approval of the ERISA litigation and dismissal with prejudice occurred in November 2005.

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. From 2000 to April 2003, Mr. Chappel founded and served as chief executive officer of a development business in Chicago, Illinois. From 1987 though February 2000, Mr. Chappel served in various financial, administrative and operational leadership positions for Waste Management, Inc., including twice serving as chief financial officer, during 1997 and 1998 and most recently during 1999 through February 2000.

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Alan S. Armstrong has served as the chief operating officer and a director of our general partner since February 2005. Since February 2002, Mr. Armstrong has served as a senior vice president of Williams responsible for heading Williams midstream business unit. 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. From 1997 to 1998, Mr. Armstrong was vice president of retail energy in Williams energy services business unit. Prior to this, Mr. Armstrong served in various operations, engineering and commercial leadership roles within Williams.

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. Prior to joining Williams in December 2002, Mr. Bender was senior vice president and general counsel with NRG Energy, Inc., a position held since June 2000. Mr. Bender was vice president, general counsel and secretary of NRG Energy from June 1997 to June 2000. NRG Energy filed a voluntary bankruptcy petition during 2003 and its plan of reorganization was approved in December 2003.

Thomas C. Knudson has served as a director of our general partner since November 2005. Mr. Knudson has served as a member of the board of directors of Bristow Group Inc. (formerly Offshore Logistics, Inc.), a leading provider of helicopter transportation services to the oil and gas industry, since June 2004. Mr. Knudson has served as chairman of the board of directors of Bristow Group Inc. since August 2006. Mr. Knudson has also served as a director of NATCO Group Inc., a leading provider of wellhead process equipment, systems and services used in the production of oil and gas, since April 2005. From 2000 to 2003, Mr. Knudson was a senior vice president of ConocoPhillips.

Bill Z. Parker has served as a director of our general partner since August 2005. Mr. Parker served as a director for Latigo Petroleum, Inc., a privately-held independent oil and gas production company, from January 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 is the president of Syrus Global, a provider of ethics, compliance and reputation management solutions. Ms. Peterson has served as a director of Hanesbrands Inc., an apparel company, since August 2006. Ms. Peterson has served as a director for RIM Finance, LLC, a wholly owned subsidiary of Research In Motion, Ltd., the maker of the BlackBerry^{tm} handheld device, since 2000. 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 August 2004, she served as a director of Fleming Companies. From December 2000 to December 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. Following the bankruptcy of Fleming Companies in 2003, Ms. Peterson was named as a defendant, along with each other member of the company s board of directors, in a securities class action. The case was settled and all claims against Ms. Peterson were released and dismissed after the court s approval of the settlement which became a final judgment in December 2005. Ms. Peterson has also been named as a defendant, along with each other member of the board of directors of Fleming Companies, in connection with a claim by trade creditors of Dunigan Fuels (a subsidiary of the former Fleming Companies) for conspiracy to breach fiduciary duties.

Phillip D. Wright has served as a director of our general partner since February 2005. Mr. Wright has served as senior vice president of Williams gas pipeline operations since January 2005. 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, Mr. Wright 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 served as president, chief operating officer and director of the general partner of Williams Energy Partners L.P. (now known as Magellan Midstream Partners, L.P.) from its initial public offering in February 2001 to the sale of Williams interests therein in June 2003. Mr. Wright was named as a defendant in four class action complaints filed under ERISA against Williams, certain members of the benefits and investment committees and certain members of the Williams board of directors, by participants in Williams Investment Plus Plan. Final court approval of the ERISA litigation and dismissal with prejudice occurred in November 2005.

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 annually reviews the independence of directors and affirmatively makes a determination that each director expected to be independent has no material relationship with our general partner (either directly or indirectly or as a partner, shareholder or officer of an organization that has a relationship with our general partner). In order to make this determination, our general partner s board of directors broadly considers all relevant facts and circumstances and applies categorical standards from our governance guidelines, which are set forth below and also available on our Internet website at *http://www.williamslp.com* under the Investor Relations caption. Under those categorical 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 $100,000 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 of the Partnership Group will be considered in determining independence under this standard.

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 or an immediate family member is a current partner of a present or former internal or external auditor for the Partnership Group, (ii) the director is a current employee of such a firm, (iii) the director has an immediate family member who is a current employee of such a firm and participates in such firm s audit, assurance or tax compliance (but not tax planning) practice or (iv) the director or an immediately family member was within the last three years (but is no longer) 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. Knudson and Parker is an independent director under the current listing standards of the New York Stock Exchange and our categorical director independence standards. In doing so, 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 relationships with our general partner, 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. Knudson serves as a director for NATCO Group Inc., which provides goods or services for certain of our subsidiaries, affiliates of Williams and Discovery. The board of directors noted that, since Mr. Knudson does not serve as an executive officer and is not a significant stockholder of NATCO Group Inc., these relationships are not material and affirmatively determined that all of the directors mentioned above are independent. Because Messrs. Armstrong, Chappel, Malcolm and Wright are employees, officers and/or directors of Williams, they are not independent under these standards.

Ms. Peterson and Messrs. Knudson 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 categorical 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. Knudson 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 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.

Executive Sessions of Non-Management Directors

The general partner s non-management board members periodically meet outside the presence of our general partners 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 or the presiding director may contact our general partner s corporate secretary or the presiding director. The contact information is published on the investor relations page of our website at *http://www.williamslp.com.*

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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: *brian.shore@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 26, 2007.

Board Committee Membership

	Audit Committee	Conflicts Committee
Thomas C. Knudson	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 is an audit committee financial expert as defined by the rules of the SEC. Ms. Peterson s biographical information 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 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.

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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.

Internet Access to Governance Documents

Our general partner s code of business conduct and ethics, governance guidelines and the charter for the audit committee are available on our Internet website at *http://www.williamslp.com* under the Investor Relations caption. We will provide, free of charge, a copy of our code of business conduct and ethics or any of our other 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.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our general partner s 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. Officers and directors of our general partner and greater than 10% common 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, 2006 our general partner s officers, directors and greater than 10% common unitholders filed all reports they were required to file under Section 16(a).

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

CEO/CFO Certifications

We submitted the certification of Steven J. Malcolm, our general partner s chairman of the board and chief executive officer, to the New York Stock Exchange pursuant to NYSE Section 303A.12(a) on September 11, 2006. In addition, the certificates of our chief executive officer and chief financial officer as required by Section 302 of the Sarbanes-Oxley Act of 2002 are filed as Exhibits 31.1 and 31.2 to this annual report.

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 and oversee 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 required by standard No. 1 of the independence standards board (independence discussions with audit committees) provided to the audit committee by Ernst & Young LLP;

discussed with Ernst & Young LLP its independence from management and Williams Partners L.P. and considered the compatibility of the provision of nonaudit services by the independent auditors with the auditors independence;

discussed with Ernst & Young LLP the matters required to be discussed by statement on auditing standards No. 61 (communications with audit committees);

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;

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, 2006, for filing with the SEC; and

approved the selection and appointment of Ernst & Young LLP to serve as Williams Partners L.P. s independent auditors.

This report has been furnished by the members of the audit committee of the board of directors:

Alice M. Peterson chairman

Bill Z. Parker

Thomas C. Knudson

February 20, 2007

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. We have no compensation committee and the compensation committee of our general partner was dissolved on November 28, 2006. 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. A full discussion of the policies and programs of the compensation committee of Williams will be set forth in the proxy statement for Williams 2007 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

None of the executive officers of our general partner received, other than Messrs. Armstrong and Malcolm, directly or indirectly, more than $100,000 for services performed for us in 2006.

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, and our principal financial officer, Donald R. Chappel, who also serves as the chief financial officer of Williams, will be set forth in the proxy statement for Williams 2007 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. Further information regarding the portion of Mr. Armstrong 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.

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. 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,
Thomas C. Knudson, Steven J. Malcolm
Bill Z. Parker, Alice M. Peterson,
Phillip D. Wright

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. Non-employee directors each receive an annual compensation package consisting of the following: (a) $50,000 cash retainer; (b) restricted units representing our limited partnership interests valued at $25,000 in the aggregate; and (c) $5,000 cash for service on the conflicts or audit committees of the board of directors. The annual compensation package is paid to each non-employee director based on their service on the board of directors for the period beginning on August 22 of each fiscal year and ending on August 21 of each fiscal year. If a non-employee director s service on the board of directors commences on or after December 1 of a fiscal year, such non-employee director will receive a prorated annual compensation package for such fiscal year. In addition to the annual compensation package, each non-employee director receives a one-time grant of restricted units valued at $25,000 on the date of first election to the board of directors. Restricted units awarded to non-employee directors under the annual compensation package or upon first election to the board of directors are granted under the Williams Partners GP LLC Long-Term Incentive Plan and vest 180 days after the date of grant. Cash distributions are be paid on these restricted units. 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 2006:

Director Compensation Fiscal Year 2006

Name	Fees Earned or Paid in Cash	Unit Awards(1)	All Other Compensation	Total
Thomas C. Knudson	$ 60,000	$ 63,394.66(2)	$ 0	$ 123,394.66
Bill Z. Parker	$ 60,000	$ 82,738.39(3)	$ 0	$ 142,738.39
Alice M. Peterson	$ 60,000	$ 82,738.39(4)	$ 0	$ 142,738.39

(1) Awards were granted under the Williams Partners GP LLC Long-Term Incentive Plan. Awards are in the form of restricted units and are shown using a dollar value equal to the 2006 compensation expense computed in accordance with FAS 123(R). Cash distributions are paid on these restricted units at the same time and same rate as dividends paid to our unitholders.

(2) The grant date fair value for the 2006 restricted units for Mr. Knudson is $25,013. At fiscal year end, Mr. Knudson had an aggregate of 710 restricted units outstanding.

(3) The grant date fair value for the 2006 restricted units for Mr. Parker is $25,013. At fiscal year end, Mr. Parker had an aggregate of 710 restricted units outstanding.

(4) The grant date fair value for the 2006 restricted units for Ms. Peterson is $25,013. At fiscal year end, Ms. Peterson had an aggregate of 710 restricted units outstanding.

Long-Term Incentive Plan

In connection with our IPO, 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. On November 28, 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 on November 28, 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. 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.

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 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, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

Restricted Units and Phantom Units

A restricted unit is a common unit subject to forfeiture prior to the vesting of the award. A phantom unit will be a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equivalent to the value of a common unit. The board of directors of our general partner may determine to make grants under the plan of restricted units and phantom units to employees, consultants and directors containing such terms as the board of directors shall determine. The board of directors determines the period over which restricted units and phantom units granted to employees, consultants and directors will vest. The board of directors may base its determination upon the achievement of specified financial objectives. In addition, the restricted units and phantom units will vest upon a change of control of Williams Partners L.P., our general partner or Williams, unless provided otherwise by the board of directors.

If a grantee s employment, service relationship or membership on the board of directors terminates for any reason, the grantee s restricted units and phantom units will be automatically forfeited unless, and to the extent, the board of directors provides otherwise. Common units to be delivered in connection with the grant of restricted units or upon the vesting of phantom units may be common units acquired by our general partner on the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person or any combination of the foregoing. Our general partner is entitled to reimbursement by us for the cost incurred in acquiring common units. Thus, the cost of the restricted units and delivery of common units upon the vesting of phantom units will be borne by us. If we issue new common units in connection with the grant of restricted units or upon vesting of the phantom units, the total number of common units outstanding will increase. The board of directors of our general partner, in its discretion, may grant tandem distribution rights with respect to restricted units and tandem distribution equivalent rights with respect to phantom units.

Unit Options and Unit Appreciation Rights

The long-term incentive plan permits the grant of options covering common units and the grant of unit appreciation rights. A unit appreciation right is an award that, upon exercise, entitles the participant to receive the excess of the fair market value of a unit on the exercise date over the exercise price established for the unit appreciation right. Such excess may be paid in common units, cash or a combination thereof, as determined by the board of directors in its discretion. Our general partner s board of directors may make grants of unit options and unit appreciation rights under the plan to employees, consultants and directors containing such terms as the board of directors shall determine. Unit options and unit appreciation rights may not have an exercise price that is less than the fair market value of the common units on the date of grant. In general, unit options and unit appreciation rights granted will become exercisable over a period determined by the board of directors. In addition, the unit options and unit appreciation rights will become exercisable upon a change in control of Williams Partners L.P., our general partner or Williams, unless provided otherwise by the board of directors. The board of directors, in its discretion may grant tandem distribution equivalent rights with respect to unit options and unit appreciation rights.

Upon exercise of a unit option (or a unit appreciation right settled in common units), our general partner will acquire common units on the open market or directly from us or any other person or use common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring these common units and the proceeds received from a participant at the time of exercise. Thus, the cost of the unit options (or a unit appreciation right settled in common units) will be borne by us. If we issue new common units upon exercise of the unit options (or a unit appreciation right settled in common units), the total number of common units outstanding will increase, and our general partner will pay us the proceeds it

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receives from an optionee upon exercise of a unit option. The availability of unit options and unit appreciation rights is intended to furnish additional compensation to employees, consultants and directors and to align their economic interests with those of common unitholders.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The following table sets forth the beneficial ownership of 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 named executive officers of our general partner; and
- all directors and executive officers of our general partner as a group.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

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.

Percentage of total units beneficially owned is based on 39,358,798 units outstanding. Unless otherwise noted below, the address for the beneficial owners listed below is One Williams Center, Tulsa, Oklahoma 74172-0172.

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Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Beneficially Owned	Class B Units Beneficially Owned	Percentage of Class B Units Beneficially Owned	Percentage of Total Units Beneficially Owned
The Williams Companies, Inc.(a)	1,250,000	4.9%	7,000,000	100.0%			21%
Williams Energy Services, LLC(a)	821,761	3.2	4,601,861	65.7			13.8
Williams Energy, L.L.C.	447,308	1.8	2,504,925	35.8			7.5
Williams Discovery Pipeline LLC	215,980	.8	1,209,486	17.3			3.6
Williams Partners Holdings LLC	428,239	1.7	2,398,139	34.2			7.2
MAPCO Inc.(a)	447,308	1.8	2,504,925	35.8			7.5
Prudential Financial, Inc.(b)	2,776,949	10.87					7.06
Jennison Utility Fund(c)	714,680	2.8			2,062,269	30.3%	7.1
Goldman Sachs & Co.(d)	357,340	1.4			1,031,134	15.2	3.5
GPS Income Fund (Cayman) LTD(e)	164,376	.6			474,321	7.0	1.6
Tortoise Capital Advisors L.L.C.(f)	1,487,094	1.0			721,796	10.6	5.6
Perry Partners L.P.(g)	178,670	.7			515,566	6	8
The Cushing MLP Opportunity Fund I, LP(h)	178,670	.7			515,566	7.6	1.8
Alan S. Armstrong	10,000	*					*
James J. Bender	2,000	*					*
Donald R. Chappel	10,000	*					*
Steven J. Malcolm(i)	25,100	*					*
Bill Z. Parker	8,036	*					*
Alice M. Peterson	3,036	*					*
Thomas C. Knudson	2,204	*					*
Phillip D. Wright	2,000	*					*
All directors and executive officers as a group (eight persons)	62,376	*					*

* Less than 1%.

(a) As noted in the Schedule 13D/A filed with the SEC on December 19, 2006, The Williams Companies, Inc. is the ultimate parent company of Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Discovery Pipeline LLC and Williams Partners Holdings LLC and may, therefore, be deemed to beneficially own the units held by Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Discovery Pipeline LLC and Williams Partners Holdings LLC. The Williams Companies, Inc. s common stock is 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). Williams Energy Services, LLC is the record owner of 158,473 common units and 887,450 subordinated units and, as the sole stockholder of MAPCO Inc. and the sole member of Williams Discovery Pipeline LLC, may, pursuant to Rule 13d-3, be deemed to beneficially own the units beneficially owned by MAPCO Inc. and Williams Discovery Pipeline 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.

(b) Based solely on the Schedule 13G filed with the SEC on February 9, 2007, Prudential Financial, Inc. (Prudential), a Parent Holding Company as defined in the Securities Exchange Act of 1934, may be deemed to be the beneficial owner of securities beneficially owned by the Registered Investment Advisors listed in such Schedule 13G, of which Prudential is the direct or indirect parent, and may have direct or indirect voting power over 2,776,949 common units which are held for Prudential s benefit or for the benefit of its clients by its separate accounts, externally managed accounts, registered investment companies subsidiaries and/or affiliates. The Schedule 13G notes that Prudential reported the combined holdings of these entities for the purpose of administrative convenience. The address of Prudential is 751 Broad Street, Newark, New Jersey 07102-3777.

(c) The address of Jennison Utility Fund is 466 Lexington Avenue, New York, New York 10017.

(d) The address of Goldman Sachs & Co. is 85 Broad Street, 29th Floor, New York, New York 10004.

(e) Also includes 64,321 common units and 185,604 Class B units held by GPS Income Fund LP and 20,011 common units and 57,743 Class B units held by GPS High Yield Equities Fund. The address of GPS Income Fund (Cayman) LTD is 1000 Wilshire Blvd., Suite 900, Santa Monica, California, 90401.

(f) According to the Schedule 13G filed with the SEC on February 13, 2007, Tortoise Capital Advisors, L.L.C. (TCA) acts as an investment advisor to certain closed-end investment companies registered under the Investment Company Act of 1940. TCA, by virtue of investment advisory agreements with these investment companies, has all investment and voting power over the units owned of record by these companies. In addition, TCA acts as an investment advisor to certain managed accounts. Under contractual agreements with individual account holders, TCA, with respect to the units held in the managed accounts, shares investment and voting power with certain account holders, and has no voting power but shares investment power with certain other account holders. Accordingly, TCA may be deemed to beneficially own 1,487,094 common units and 721,796 Class B units. The address of TCA is 10801 Mastin Boulevard, Suite 222 Overland Park, Kansas 66210.

(g) Also includes 5,717 common units and 16,498 Class B units held by Perry Commitment Fund L.P. The address of Perry Partners L.P. is 767 5th Ave, 19th Floor, New York, New York 10153.

(h) Also includes 35,734 common units and 103,113 Class B units held by Swank MLP Convergence Fund, LP. The address of The Cushing MLP Opportunity Fund I, LP is 3300 Oak Lawn Avenue, Suite 650 Dallas, Texas 75219.

(i) Represents units beneficially owned by Mr. Malcolm that are held by the Steven J. Malcolm Revocable Trust.

The following table sets forth, as of February 20, 2007, the number of shares of common stock of Williams 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	123,999	21,378	145,377	*
James J. Bender	139,732	21,378	161,110	*

Donald R. Chappel	229,077	32,306	261,383	*
Steven J. Malcolm	794,117	158,333	952,450	*
Bill Z. Parker				
Alice M. Peterson				
Thomas C. Knudson				
Phillip D. Wright	217,385	21,378	238,763	*
All directors and executive officers as a group (eight persons)	1,504,310	254,773	1,759,083	*

* Less than 1%.

(a) Includes shares held under the terms of incentive and investment plans as follows: Mr. Armstrong, 14 shares in The Williams Companies Investment Plus Plan, 88,368 restricted stock units and 35,617 beneficially owned shares; Mr. Bender, 6,000 shares owned by children, 88,368 restricted stock units and

45,364 beneficially owned shares; Mr. Chappel, 129,434 restricted stock units and 99,643 beneficially owned shares; Mr. Malcolm, 45,297 shares in The Williams Companies Investment Plus Plan, 393,092 restricted stock units and 355,728 beneficially owned shares; and Mr. Wright, 14,964 shares in The Williams Investment Plus Plan, 88,368 restricted stock units and 114,053 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 20, 2007. Shares subject to options cannot be voted.

Securities Authorized for Issuance Under Equity Compensation Plans(1)

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, 2006. For more information about this plan, which did not require approval by our limited partners, please read Note 13 of our Notes to Consolidated Financial Statements and Executive Compensation Long-Term Incentive Plan. Please read Executive Compensation Long Term Incentive Plan for a description of the material features of the plan, including the awards that may be granted under the 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	2,130		691,724
Total	2,130(1)		691,724

(1) Represents unvested restricted units granted pursuant to the Williams Partners GP LLC Long-Term Incentive Plan as of December 31, 2006. The restricted units vested on February 18, 2007. No value is shown in column (b) of the table because the restricted units do not have an exercise price. To date, the only grants under the plan have been grants of restricted units.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Transactions with Related Persons

Affiliates of our general partner own 1,250,000 common units and 7,000,000 subordinated units representing a 20.5% 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 5 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 1,250,000 common units and all of the subordinated 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 and its affiliates	Our general partner does not receive a management fee or other compensation for 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 will 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. The expenses that are allocable to us vary for each employee of an affiliate of our general partner performing services on our behalf and are based on the amount of time such employee devotes to matters related to our business as compared to the amount of time such employee devotes to matters related to the business Williams and its other affiliates. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. There is no cap on the amount that may be paid or reimbursed to our general partner for expenses incurred on our behalf, except that pursuant to the omnibus agreement, Williams will provide a partial credit for general and administrative expenses that we incur for a period of five years following our IPO of common units in August 2005. Please read Omnibus Agreement below for more information.

For the fiscal year ended December 31, 2006, our general partner allocated $35,822 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, $17,985 of salary and non-equity incentive plan compensation expense to us for Donald R. Chappel, the chief financial officer of our general partner and $156,115 of salary and non-equity incentive plan compensation expense to us for Alan S. Armstrong, the chief operating officer of our general partner. Our general partner also allocated to us $71,449 for Steven J. Malcolm, $21,100 for Don Chappel and $91,475 for Alan Armstrong, 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 and Armstrong, which allocation did not exceed $10,000 for any of these persons. The foregoing amounts exclude expenses allocated by Williams to Discovery. No awards were granted to our general partner s executive officers under the Williams Partners GP LLC Long-Term Incentive Plan in 2005 or 2006 and no other executive officer of our general partner, other than Messrs. Armstrong and Malcolm received total compensation allocable to us in excess of $100,000. 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, and Mr. Chappel, the chief financial officer of our general partner who is also the chief financial officer of Williams, will be set forth in the proxy statement for Williams 2007 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, 2006, we incurred approximately $87.3 million in operating and maintenance and general and administrative expenses from Williams incurred on our behalf pursuant to the partnership agreement.

Omnibus Agreement

Upon the closing of our initial public offering, 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

Williams will provide us with a five-year partial credit for general and administrative, or G&A, expenses incurred on our behalf. For 2005, the amount of this credit was $3.9 million on an annualized basis but was pro rated from the closing of our initial public offering in August 2005 through the end of the year, resulting in a $1.4 million credit. In 2006, the amount of the G&A credit was $3.2 million, and the amount of the credit will decrease by $800,000 for each subsequent year. As a result, 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.

Indemnification for Environmental and Related Liabilities

Williams agreed to indemnify us after the closing of our initial public offering 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, including:

- remediation costs associated with the KDHE Consent Orders and certain fugitive NGLs associated with our Conway storage facilities;
- the costs associated with the installation of wellhead control equipment and well meters at our Conway storage facility;

KDHE-related cavern compliance at our Conway storage facility; and

the costs relating to the restoration of the overburden along our Carbonate Trend pipeline in connection with erosion caused by Hurricane Ivan in September 2004.

Williams will not be required to indemnify us for any project management or monitoring costs. This indemnification obligation will terminate three years after the closing of our initial public offering, except in

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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, including any amounts recoverable under our insurance policy covering those remediation costs and unknown claims at Conway. 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 initial public offering are excluded from the environmental indemnity by Williams for the unknown environmental liabilities.

Williams will also indemnify us for liabilities related to:

- certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to us in connection with our initial public offering are located and failure to obtain certain consents and permits necessary to conduct our business that arise within three years after the closing of our initial public offering; and

- certain income tax liabilities attributable to the operation of the assets contributed to us in connection with our initial public offering prior to the time they were contributed.

For the year ended December 31, 2006, Williams indemnified us $2.0 million, primarily for KDHE related compliance. Including 2006, Williams has indemnified us for an aggregate of $2.5 million pursuant to the omnibus agreement.

Reimbursement for Certain Expenditures Attributable to Discovery

Williams has agreed to reimburse us for certain capital expenditures, subject to limits, including for certain excess capital expenditures in connection with Discovery s Tahiti pipeline lateral expansion project. We expect the cost of the Tahiti pipeline lateral expansion project will be approximately $69.5 million, of which our 40% share will be approximately $27.8 million. Williams will reimburse us for the excess (up to $3.4 million) of our 40% share 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. Williams will reimburse us for these capital expenditures upon the earlier to occur of a capital call from Discovery or Discovery actually incurring the expenditure. During 2006, Williams indemnified us $1.6 million for our 40% of Discovery s capital call related to this project.

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.

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

At the closing of our initial public offering in August 2005, we entered into a $20.0 million revolving credit facility with Williams as the lender. The facility was amended and restated on August 7, 2006. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility will mature on June 20, 2009 and bear interest at the same rate as would be available for borrowings under the Williams credit agreement described in Management s Discussion and Analysis of Financial Condition and Results of Operations Financial Condition and Liquidity Credit Facilities.

We are required to reduce all borrowings under our working capital credit facility to zero for a period of at least 15 consecutive days once each 12-month period prior to the maturity date of the facility.

Williams Credit Agreement

In addition, we also have the ability to borrow up to $75.0 million under the Williams credit agreement. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Financial Condition and Liquidity Credit Facilities, and Risk Factors Risks Inherent in Our Business Williams credit agreement and Williams public indentures contain financial and operating restrictions that may limit our access to credit. In addition, our ability to obtain credit in the future will be affected by Williams credit ratings.

Discovery Limited Liability Company Agreement

We, an affiliate of Williams and Duke Energy Field Services have entered into an amended and restated limited liability company agreement for Discovery. This agreement governs the ownership and management of Discovery and provides for quarterly distributions of available cash to the members. The amount of any such distributions is determined by majority approval of Discovery s management committee, which consists of representatives from each of the three owners. In addition, to the extent Discovery requires working capital in excess of applicable reserves, the Williams affiliate that is a Discovery member (Williams Energy, L.L.C.) must make capital advances to Discovery up to the amount of Discovery s two most recent prior quarterly distributions of available cash, but Discovery must repay these advances before it makes any future distributions. In addition, the owners are required to offer to Discovery all opportunities to construct pipeline laterals within an area of interest.

Under the Discovery limited liability company agreement, each member is subject to a right of first refusal in favor of the other members, except in the case of certain related-party transfers, such as between Williams and us. Accordingly, if a member identifies a potential third-party purchaser for all or a portion of its interest, that member must first offer the other members the opportunity to acquire the interest that it proposes to sell on the same terms and conditions as proposed by such potential purchaser.

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, 2006, Discovery reimbursed Williams $4.5 million for direct payroll and employee benefit costs, as well as $0.4 million for capitalized labor costs, pursuant to the operating and maintenance agreements and paid Williams $2.2 million for operation and management fees, as well as a $0.5 million fee for managing capitalized projects, pursuant to the operating and maintenance agreements.

Four Corners Purchase and Sale Agreements

On April 6, 2006, we entered into a Purchase and Sale Agreement with Williams Energy Services, LLC, Williams Field Services Group, LLC, Williams Field Services Company, LLC, our general partner and Williams Partners Operating. Pursuant to the Purchase and Sale Agreement, on June 20, 2006, we acquired a 25.1% membership interest in Four Corners for $360.0 million. The conflicts committee of the board of directors of our general partner recommended approval of the acquisition of the 25.1% interest in Four Corners. The committee retained independent legal and financial advisors to assist it in evaluating and negotiating the transaction. In recommending approval of the transaction, the committee based its decision in part on an opinion from the committee s independent financial advisor that the consideration paid by us to Williams was fair, from a financial point of view, to us and our public unitholders. In connection with the transactions contemplated by the Purchase and Sale Agreement, we contributed the 25.1% interest in Four Corners to our wholly owned subsidiary, Williams Partners Operating LLC, on June 20, 2006.

On November 16, 2006, we entered into a Purchase and Sale Agreement with Williams Energy Services, LLC, Williams Field Services Group, LLC, Williams Field Services Company, LLC, our general partner and Williams Partners Operating LLC. Pursuant to the Purchase and Sale Agreement, on December 13, 2006, we acquired the remaining 74.9% membership interest in Four Corners for $1.223 billion, subject to possible adjustment in our favor. The conflicts committee of the board of directors of our general partner recommended approval of our acquisition of the remaining interest in Four Corners. The committee retained independent legal and financial advisors to assist it in evaluating and negotiating the transaction. In recommending approval of the transaction, the committee based its decision in part on an opinion from the committee s independent financial advisor that the consideration to be paid by was fair, from a financial point of view, to us and our public unitholders. In connection with the transactions contemplated by the Purchase and Sale Agreement, we contributed the remaining 74.9% interest in Four Corners to Williams Partners Operating LLC on December 13, 2006.

Natural Gas and NGL Purchasing Contracts

Certain subsidiaries of Williams market substantially all of the NGLs and excess natural gas to which Discovery, our Conway fractionation and storage facility and our Four Corners system take title. 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 take title pursuant to base contracts for sale and purchase of natural gas and a natural gas liquids 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 Discovery, our Conway fractionation and storage facility and our Four Corners system take title have been conducted at market prices with certain subsidiaries of Williams as the counter parties. Additionally, 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, 2006, we sold $255.1 million of products to a subsidiary of Williams that purchases 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, and Discovery sold $148.4 million of NGLs to a subsidiary of Williams that purchases substantially all of the NGLs and excess natural gas to which Discovery takes title based on market pricing.

Gathering, Processing and Treating Contracts

We maintain two contracts with an affiliate of Williams, a gas gathering and treating contract and a gas gathering and processing contract. 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. Deliveries of gas under this agreement averaged approximately 52 MMcf/d during 2006. 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. Deliveries of gas under these agreements averaged approximately 109 MMcf/d during 2006. 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 $42.2 million in 2006.

Natural Gas Purchases

We purchase natural gas for fuel and shrink replacement from Williams Power Company, an affiliate of Williams. With the exception of volumes purchased pursuant to the contract discussed in the immediately following paragraph, these purchases are made at market rates at the time of purchase. We purchased approximately $78.2 million of natural gas for fuel and shrink replacement from Williams Power Company during 2006.

Four Corners maintains a contract with two affiliates of Williams, Williams Power Company, Inc. and Williams Flexible Generation, LLC under which natural gas is supplied for consumption at the co-generation plant. The co-generation plant produces waste heat that assists in the operation of the Milagro treating plant. During 2006, pursuant to a predecessor contract that expired on December 31, 2006, Four Corners purchased $23.1 million of natural gas from Williams Flexible Generation, LLC. This contract was renegotiated with a term that will expire on December 31, 2012, or when the companies are no longer affiliated with each other, whichever occurs earlier.

For the year ended December 31, 2006 we purchased a gross amount of $16.2 million of natural gas for our Conway fractionator from an affiliate of Williams.

Balancing Services Agreement

We maintain a balancing services contract with Williams Power Company, Inc., an affiliate of Williams. Pursuant to this agreement, Williams Power Company 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, Williams Power Company 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 Williams Power Company at current market prices. Historically, Williams Power Company 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, 2006:

- we distributed $15.0 million to affiliates of Williams as quarterly distributions on their common units, subordinated units, 2% general partner interest and incentive distribution rights;

we purchased $14.9 million of NGLs to replenish deficit product positions from a subsidiary of Williams based on market pricing; and we previously sold electricity and capacity to Williams Power Company at the Ignacio plant. The revenue from these sales during 2006 were $0.4 million.

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 the Partnership and its 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 the Partnership or to 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 Accountant Fees and Services*

Fees for professional services provided by our independent auditors, Ernst & Young LLP, for each of the last two fiscal years in each of the following categories are:

	2006	2005
	(Thousands)	
Audit Fees	$ 1,459	$ 1,624
Audit-Related Fees		
Tax Fees	25	
All Other Fees		
	$ 1,484	$ 1,624

Fees for audit services in 2006 and 2005 include fees associated with the annual audit, the reviews of our quarterly reports on Form 10-Q, and services provided in connection with other filings with the SEC. Tax fees for 2006 include fees for review of our federal tax return. The audit fees for 2006 and 2005 included in the table above include $0.4 million for services provided in connection with the acquisition of Four Corners and $1.2 million for services rendered in connection with our initial public offering, respectively.

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 our general partner s audit committee for which advance approval is requested. 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 the 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 permissible 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 2006, 100% of Ernst & Young LLP s fees were pre-approved by the audit committee. The audit committee s pre-approval policy with respect to audit and non-audit services is provided as an exhibit to this report.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) *1 and 2. Williams Partners L.P. financials*

	Page
Covered by reports of independent auditors:	
Consolidated balance sheets at December 31, 2006 and 2005	75
Consolidated statements of income for each of the three years ended December 31, 2006	76

Consolidated statement of partners capital for each of the three years ended December 31, 2006	77
Consolidated statements of cash flows for each of the three years ended December 31, 2006	78
Notes to consolidated financial statements	79
Not covered by reports of independent auditors:	
Quarterly financial data (unaudited)	102

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

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

The exhibits listed below are filed as part of this annual 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 (attached as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on April 7, 2006.
*§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 (attached as Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File 001-32599) filed with the SEC on November 21, 2006).
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*Exhibit 10.6	Third Amended and Restated Limited Liability Company Agreement for Discovery Producer Services LLC (attached as Exhibit 10.7 to Amendment No. 1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on June 24, 2005).
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*#Exhibit 10.8	Director Compensation Policy dated November 29, 2005 (attached as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on December 1, 2005).
*#Exhibit 10.9	Form of Grant Agreement for Restricted Units (attached as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on December 1, 2005).

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*Exhibit 10.12	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 (attached as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on June 20, 2006).
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+Exhibit 23	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
+Exhibit 24	Power of attorney together with certified resolution.
+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.
+Exhibit 99.1	Pre-approval policy with respect to audit and non-audit services of the audit committee of the board of directors of Williams Partners GP LLC.
+Exhibit 99.2	Williams Partners GP LLC Financial Statements.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

\+ 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.

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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/ William H. Gault
William H. Gault
Attorney-in-fact

Date: February 28, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Steven J. Malcolm* Steven J. Malcolm	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 28, 2007
/s/ Donald R. Chappel* Donald R. Chappel	Chief Financial Officer and Director (Principal Financial Officer)	February 28, 2007
/s/ Ted T. Timmermans* Ted T. Timmermans	Chief Accounting Officer and Controller (Principal Accounting Officer)	February 28, 2007
/s/ Alan S. Armstrong* Alan S. Armstrong	Chief Operating Officer and Director	February 28, 2007
/s/ Bill Z. Parker* Bill Z. Parker	Director	February 28, 2007
/s/ Alice M. Peterson* Alice M. Peterson	Director	February 28, 2007
/s/ Thomas C. Knudson*	Director	February 28, 2007

Thomas C. Knudson

/s/ Phillip D. Wright*	Director	February 28, 2007
Phillip D. Wright		
*By: /s/ William H. Gault		February 28, 2007
William H. Gault *Attorney-in-fact*		

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INDEX TO EXHIBITS

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