Western Gas Partners LP
Form 10-K
March 13, 2009

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

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

For the fiscal year ended December 31, 2008

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: 001-34046

WESTERN GAS PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	**26-1075808**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1201 Lake Robbins Drive The Woodlands, Texas	**77380**
(Address of principal executive offices)	*(Zip Code)*

(832) 636-6000
(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 Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

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

The aggregate market value of the Partnership s common units representing limited partner interests held by non-affiliates of the registrant was approximately $350.7 million on June 30, 2008 based on the closing price as reported on the New York Stock Exchange.

At February 27, 2009, there were 29,093,197 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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DESCRIPTION

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DEFINITIONS

As generally used within the energy industry and in this Annual Report on Form 10-K, the identified terms have the following meanings:

Backhaul: Pipeline transportation service in which the nominated gas flow from delivery point to receipt point is in the opposite direction as the pipeline s physical gas flow.

Barrel or Bbl: 42 U.S. gallons measured at 60 degrees Fahrenheit.

Bcf/d: One billion cubic feet per day.

Btu: British Thermal Unit.

Condensate: A natural gas liquid with a low vapor pressure mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Delivery point: The point where gas or natural gas liquids are delivered by a processor or transporter to a producer, shipper or purchaser, typically the inlet at the interconnection between the gathering or processing system and the facilities of a third-party processor or transporter.

Drip condensate: Heavier hydrocarbon liquids that fall out of the natural gas stream and are recovered in the gathering system without processing.

Dry gas: A gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.

End-use markets: The ultimate users/consumers of transported energy products.

Forward-haul: Pipeline transportation service in which the nominated gas flow from receipt point to delivery point is in the same direction as the pipeline s physical gas flow.

Long ton: A British unit of weight equivalent to 2,240 pounds.

LTD: One long ton per day.

MMBtu: One million British Thermal Units.

MMBtu/d: One million British Thermal Units per day.

MMcf/d: One million cubic feet per day.

Natural gas: Hydrocarbon gas found in the earth composed of methane, ethane, butane, propane and other gases.

Natural gas liquids or NGLs: The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

Plant condensate: Heavier hydrocarbon liquids that fall out of the natural gas stream and are recovered at the plant.

Play: A proven geological formation that contains known or potential commercial amounts of petroleum and/or natural gas.

Psia: Pounds per square inch, absolute; refers to the pressure resulting from a one pound-force applied to an area of one square inch, including local atmospheric pressure.

Receipt point: The point where production is received by or into a gathering system or transportation pipeline.

Residue gas: The natural gas remaining after being processed or treated.

Sour gas: Natural gas containing more than four parts per million of hydrogen sulfide.

Tailgate: The point at which processed natural gas and/or natural gas liquids leave a processing facility for end-use markets.

Tcf: One trillion cubic feet of natural gas.

Wellhead: The equipment at the surface of a well used to control the well s pressure; the point at which the hydrocarbons and water exit the ground.

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WESTERN GAS PARTNERS, LP
PART I

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

Unless the context clearly indicates otherwise, references in this report to the Partnership, we, our, us or like terms, when used in the historical context, refer to the combined financial results and operations of Anadarko Gathering Company LLC and Pinnacle Gas Treating LLC from their inception through the closing date of our initial public offering and to Western Gas Partners, LP and its subsidiaries thereafter, combined with the financial results and operations of MIGC LLC and the Powder River assets, as described in *Powder River Acquisition* below, from August 23, 2006 thereafter. When used in the present tense or prospectively, the Partnership, we, our, us or like terms refer Western Gas Partners, LP and its subsidiaries.

Anadarko refers to Anadarko Petroleum Corporation (NYSE: APC) and its subsidiaries and affiliates, other than Western Gas Partners, LP and Western Gas Holdings, LLC, our general partner. Anadarko Petroleum Corporation refers to Anadarko Petroleum Corporation excluding its subsidiaries and affiliates. AGC refers to Anadarko Gathering Company LLC, PGT refers to Pinnacle Gas Treating LLC and MIGC refers to MIGC LLC. Predecessor refers to AGC, PGT and MIGC. Each of AGC, PGT, MIGC, our general partner and the Partnership is an indirect subsidiary of Anadarko.

Available 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, or the SEC, under the Securities Exchange Act of 1934. From time-to-time, we may also file registration and related statements pertaining to equity or debt offerings. We provide access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing, on our Internet site located at www.westerngas.com. You may also read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC s Internet website at *www.sec.gov.*

Our Corporate Governance Guidelines, Code of Ethics for our Chief Executive Officer and Senior Financial Officers, Code of Business Conduct and Ethics and the charters of the audit committee and the special 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 corporate secretary at our principal executive office.

Our principal executive offices are located at 1201 Lake Robbins Drive, The Woodlands, TX 77380-1046. Our telephone number is 832-636-6000.

GENERAL

We are a growth-oriented Delaware limited partnership organized by Anadarko to own, operate, acquire and develop midstream energy assets. With midstream assets in East and West Texas, the Rocky Mountains and the Mid-Continent, we are engaged in the business of gathering, compressing, treating, processing and transporting natural gas for Anadarko and other producers and customers. Approximately 74% of our services are provided under long-term contracts with fee-based rates and approximately 22% of our services are provided under percent-of-proceeds contracts, based on operating income for the year ended December 31, 2008. Effective January 1, 2009, we have entered into fixed-price swap agreements with Anadarko to manage the future commodity price risk otherwise inherent in our percent-of-proceeds contracts. A substantial part of our business is conducted with Anadarko and governed by contracts which were entered into during 2008 with an initial term of 10 years. Certain contracts with third parties extend for primary terms of up to 20 years.

We believe that one of our principal strengths is our relationship with Anadarko. During each of the past three years, over 80% of our total natural gas gathering, processing and transportation volumes were comprised of natural gas production owned or controlled by Anadarko. In addition, Anadarko has dedicated to us all of the natural gas production it owns or controls from (i) wells that are currently connected to our gathering systems, and (ii) additional wells that are drilled within one mile of wells connected to our gathering systems, as the systems currently exist and as they are expanded to connect additional wells in the future. As a result, this dedication will continue to expand as additional wells are connected to our gathering systems.

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Our operations and activities are managed by our general partner, Western Gas Holdings, LLC, a wholly owned subsidiary of Anadarko. We expect to utilize the significant experience of Anadarko s management team to execute our growth strategy, which includes acquiring and constructing additional midstream assets. As of December 31, 2008, Anadarko s total domestic midstream asset portfolio, excluding assets we own, consists of 19 gathering systems with an aggregate throughput of approximately 2.3 Bcf/d, 8,100 miles of pipeline, and 18 processing and/or treating facilities.

SEGMENTS

Our operations are organized into a single business segment which engages in gathering, compressing, processing, treating and transporting Anadarko and third-party natural gas production in the United States. Information on our key measure of profit is included in *Note 12 Segment Information* of the notes to the consolidated financial statements included in *Item 8 Financial Statements and Supplementary Data* in this Form 10-K.

INITIAL PUBLIC OFFERING

On May 14, 2008, we closed our initial public offering of 18,750,000 common units at a price of $16.50 per unit. On June 11, 2008, we issued an additional 2,060,875 common units to the public pursuant to the partial exercise of the underwriters over-allotment option. We refer to the May 14 and June 11 transactions collectively as our initial public offering. Our common units are listed on the New York Stock Exchange under the symbol WES.

In connection with our initial public offering, Anadarko contributed the assets and liabilities of AGC, PGT and MIGC to us in exchange for 1,083,115 general partner units, representing a 2.0% general partner interest in the Partnership, 100% of our partnership incentive distribution rights, or IDRs, and 5,725,431 common units and 26,536,306 subordinated units. The common units held by Anadarko include 751,625 common units issued to Anadarko following the expiration of the underwriters over-allotment option and represent the portion of the common units for which the underwriters did not exercise their over-allotment option. We refer to AGC, PGT and MIGC as our initial assets.

POWDER RIVER ACQUISITION

On December 19, 2008, we acquired certain midstream assets from Anadarko for consideration consisting of $175.0 million cash, which was financed by borrowing $175.0 million from Anadarko pursuant to the terms of a five-year term loan agreement, 2,556,891 of our common units and 52,181 of our general partner units. The acquired assets consisted of (i) a 100% ownership interest in the Hilight System, (ii) a 50% interest in the Newcastle System and (iii) a 14.81% limited liability company membership interest in Fort Union Gas Gathering, L.L.C. We refer to these assets collectively as our Powder River assets. These assets provide a combination of gathering, treating and processing services in the Powder River Basin area of Wyoming.

Our initial public offering and Powder River acquisition are considered transfers of net assets between entities under common control. Anadarko acquired MIGC and the Powder River assets in connection with its August 23, 2006 acquisition of Western Gas Resources, Inc., or Western. The financial information included in this Annual Report on Form 10-K includes the combined financial results and operations of AGC and PGT from their inception through May 14, 2008 and of the Partnership thereafter, combined with the financial results and operations of MIGC and the Powder River assets beginning on August 23, 2006.

Following the closing of the Powder River acquisition:

- Anadarko holds 1,135,296 general partner units, representing a 2.0% general partner interest in the Partnership, and 100% of the IDRs;
- Anadarko holds 8,282,322 common units and 26,536,306 subordinated units, representing an aggregate 61.3% limited partner interest in the Partnership; and
- the public holds 20,810,875 common units, representing a 36.7% limited partner interest in the Partnership.

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OUR ASSETS AND AREAS OF OPERATION

Our assets consist of nine gathering systems, six natural gas treating facilities, two gas processing facilities and one interstate pipeline that is regulated by the Federal Energy Regulatory Commission or FERC. Our assets are located in East and West Texas, the Rocky Mountains (Utah and Wyoming) and the Mid-Continent (Kansas and Oklahoma). The following table provides information regarding our assets by geographic region as of or for the year ended December 31, 2008:

Area	Asset Type	Length (miles)	Approximate number of receipt points	Gas compression (horsepower)	Treating capacity (MMcf/d)	Average throughput (MMcf/d)
East Texas	Gathering and Treating	587	819	44,432	502	460
West Texas	Gathering	108	77			152
Rocky Mountains	Gathering and Treating(1)	432	179	20,385	386	164
	Gathering and Processing(2)	1,130	801	29,781		30
	Transportation	264	19	29,696		171
Mid-Continent	Gathering	2,073	1,555	102,257		131
Total		4,594	3,450	226,551	888	1,108

(1) *Includes Fort Union Gas Gathering LLC, or Fort Union, in which we have a 14.81% interest. Volumes represent our proportionate share of Fort Union s gross volumes.*

(2) *Includes the Newcastle gathering system, in which we have a 50.00% interest.*

STRATEGY

Our primary business objective is to increase our cash distributions per unit over time. We intend to accomplish this objective by executing the following strategy:

Pursuing accretive acquisitions. We expect to continue to pursue accretive acquisition opportunities within the midstream energy industry from Anadarko and third parties.

Capitalizing on organic growth opportunities. We expect to grow certain of our systems organically over time by meeting Anadarko s and our other customers gathering needs that result from their drilling activity in our areas of operation.

Attracting third-party volumes to our systems. We actively market our midstream services to and pursue strategic relationships with third-party producers with the intention of attracting additional volumes and/or expansion opportunities.

Minimizing commodity price exposure. The majority of our midstream services are provided under fee-based arrangements. In addition, we entered into fixed-price swap agreements with Anadarko to manage commodity price risk otherwise associated with our percent-of-proceeds contracts. We intend to continue to limit our direct exposure to commodity price changes.

COMPETITIVE STRENGTHS

We believe that we are well positioned to successfully execute our strategy and achieve our primary business objective because of the following competitive strengths:

Affiliation with Anadarko. We believe Anadarko, as the indirect owner of our general partner interest, all of the IDRs and a 61.3% limited partner interest in us, is motivated to promote and support the successful execution of our business plan and to pursue projects that enhance the value of our business.

Relatively stable and predictable cash flow. Our cash flow is largely protected from fluctuations caused by commodity price volatility due to (i) the long-term nature of our fee-based agreements and (ii) fixed-price swap agreements which limit our exposure to commodity price changes with respect to our percent-of-proceeds contracts.

Well-positioned, well-maintained and efficient assets. We believe that our established positions in our areas of operation provide us with opportunities to expand and attract additional volumes to our systems. Moreover, our systems include high-quality, well-maintained assets for which we have implemented modern processing, treating, measuring and operating technologies.

Financial flexibility to pursue expansion and acquisition opportunities. We currently have up to $100.0 million of borrowing capacity available to us under Anadarko s revolving credit facility as well as a $30.0 million working capital facility. We believe our operating cash flow, borrowing capacity, ability to finance acquisitions through Anadarko and access to debt and equity capital markets provide us with the financial flexibility necessary to execute or strategy across capital-market cycles.

Experienced management team. Members of our general partner s management team have extensive experience in building, acquiring, integrating, financing and managing midstream assets. Our relationship with Anadarko provides us with the services of experienced personnel who successfully managed our assets and operations while they were owned by Anadarko.

We believe that we will effectively leverage our competitive strengths to successfully implement our strategy; however, our business involves numerous risks and uncertainties which may prevent us from achieving our primary business objective. For a more complete description of the risks associated with our business, please read *Item 1A Risk Factors* in this Form 10-K.

OUR RELATIONSHIP WITH ANADARKO PETROLEUM CORPORATION

One of our principal attributes is our relationship with Anadarko, which indirectly owns our general partner and has a significant ownership interest in us. Anadarko is one of the largest independent oil and gas exploration and production companies in the world. Anadarko s upstream oil and gas business finds and produces natural gas, crude oil, condensate and natural gas liquids, or NGLs. As of December 31, 2008, Anadarko s total domestic midstream asset portfolio, excluding assets we own, consisted of 19 gathering systems with an aggregate throughput of approximately 2.3 Bcf/d, 8,100 miles of pipeline, and 18 processing and/or treating facilities.

Anadarko indirectly owns a 2.0% general partner interest in us, all of our IDRs and a 61.3% limited partner interest in us. We entered into an omnibus agreement with Anadarko and our general partner that governs our relationship with them regarding certain reimbursement and indemnification matters. Although our relationship with Anadarko provides us with a significant advantage in the midstream natural gas market, it is also a source of potential conflicts. For example, Anadarko is not restricted from competing with us. Given Anadarko s significant ownership of limited and general partner interests in us, we believe it will be in Anadarko s best interest for it to transfer additional assets to us over time; however, Anadarko continually evaluates acquisitions and divestitures and may elect to acquire, construct or dispose of midstream assets in the future without offering us the opportunity to acquire or construct those assets. Anadarko is under no contractual obligation to offer any such opportunities to us, nor are we obligated to participate in any such opportunities. We cannot state with any certainty which, if any, opportunities to acquire additional assets from Anadarko may be made available to us or if we will elect to pursue any such opportunities. Please see *Item 1A Risk Factors* and *Item 13 Certain Relationships and Related Transactions, and Director Independence* of this Form 10-K for more information.

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INDUSTRY OVERVIEW

The midstream natural gas industry is the link between the exploration and production of natural gas and the delivery of its components to end-use markets. Operators within this industry create value at various stages along the natural gas value chain by gathering raw natural gas from producers at the wellhead, separating the hydrocarbons into dry gas (primarily methane) and NGLs, and then routing the separated dry gas and NGL streams for delivery to end-use markets or to the next intermediate stage of the value chain. The following diagram illustrates the groups of assets found along the natural gas value chain:

Service Types. The services provided by us and other midstream natural gas companies are generally classified into the categories described below. As indicated below, we do not currently provide all of these services, although we may do so in the future.

Gathering. At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport raw, or untreated, natural gas to a central location for treating and processing. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are typically designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow gathering of additional production without significant incremental capital expenditures. In connection with our gathering services, we retain and sell drip condensate, which falls out of the natural gas stream during gathering.

Compression. Natural gas compression is a mechanical process in which a volume of natural gas at a given pressure is compressed to a desired higher pressure, which allows the natural gas to be delivered into a higher pressure system. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver natural gas into a higher pressure system. Since wells produce at progressively lower field pressures as they deplete, field compression is needed to maintain throughput across the gathering system.

Treating and Dehydration. To the extent that gathered natural gas contains contaminants, such as water vapor, carbon dioxide and/or hydrogen sulfide, such natural gas is dehydrated to remove the saturated water and treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.

Processing. Most decontaminated rich natural gas does not meet the quality standards for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components, which are extracted as NGLs.

Fractionation. Fractionation is the separation of the mixture of extracted NGLs into individual components for end-use sale. It is accomplished by controlling the temperature and pressure of the stream of mixed NGLs in order to take advantage of the different boiling points of separate products.

Transportation and Storage. Once the raw natural gas has been treated or processed and the raw NGL mix fractionated into individual NGL components, the natural gas and NGL components are stored, transported and marketed to end-use markets. Each pipeline system typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily supply-demand shifts. Our assets do not currently include storage facilities.

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Typical Contractual Arrangements. Midstream natural gas services, other than transportation and storage, are usually provided under contractual arrangements that vary in the amount of commodity price risk they carry. Three typical contract types are described below:

Fee-Based. Fee-based arrangements may be used for gathering, compression, treating and processing services. Under these arrangements, the service provider typically receives a fee for each unit of natural gas gathered and compressed at the wellhead and an additional fee per unit of natural gas treated or processed at its facility. As a result, the price per unit received by the service provider does not vary with commodity price changes, minimizing that service provider s direct commodity price risk exposure.

Percent-of-Proceeds, Percent-of-Value or Percent-of-Liquids. Percent-of-proceeds, percent-of-value or percent-of-liquids arrangements may be used for gathering and processing services. Under these arrangements, the service provider typically remits to the producers either a percentage of the proceeds from the sale of residue gas and/or NGLs or a percentage of the actual residue gas and/or NGLs at the tailgate. These types of arrangements expose the processor to commodity price risk, as the revenues from the contracts directly correlate with the fluctuating price of natural gas and NGLs.

Keep-Whole. Keep-whole arrangements may be used for processing services. Under these arrangements, the service provider keeps 100% of the NGLs produced, and the processed natural gas, or value of the gas, is returned to the producer. Since some of the gas is used and removed during processing, the processor compensates the producer for the amount of gas used and removed in processing by supplying additional gas or by paying an agreed-upon value for the gas utilized. These arrangements have the highest commodity price exposure for the processor because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs.

There are two forms of contracts utilized in the transportation and storage of natural gas, as described below:

Firm. Firm transportation service requires the reservation of pipeline capacity by a customer between certain receipt and delivery points. Firm customers generally pay a demand or capacity reservation fee based on the amount of capacity being reserved, regardless of whether the capacity is used, plus a usage fee based on the amount of natural gas transported. Firm storage contracts involve the reservation of a specific amount of storage capacity, including injection and withdrawal rights, and generally include a capacity reservation charge based on the amount of capacity being reserved plus an injection and/or withdrawal fee.

Interruptible. Interruptible transportation and storage service is typically short-term in nature and is generally used by customers that either do not need firm service or have been unable to contract for firm service. These customers pay only for the volume of gas actually transported or stored. The obligation to provide this service is limited to available capacity not otherwise used by firm customers, and as such, customers receiving services under interruptible contracts are not assured capacity on the pipeline or at the storage facility.

See *Note 2 Summary of Significant Accounting Policies* of the notes to the consolidated financial statements included in *Item 8 Financial Statements and Supplementary Data* of this Form 10-K for information regarding our contracts.

Natural Gas Demand and Production. Natural gas is a critical component of energy supply in the U.S. According to the Energy Information Administration, or the EIA, total annual domestic consumption of natural gas is expected to decrease from approximately 23.4 trillion cubic feet, or Tcf, in 2008 to approximately 22.5 Tcf in 2011, but consumption is expected to increase to approximately 24.5 Tcf by 2028. The industrial and electricity generation sectors are the largest consumers of natural gas in the U.S. During the last three years, these sectors accounted for approximately 58% of the total natural gas consumed in the U.S. In 2007, natural gas provided approximately 24% of all end-user commercial and residential energy requirements. During the last three years, the U.S. has, on average, consumed approximately 22.7 Tcf per year, with average annual domestic production of approximately 19.4 Tcf during the same period. The EIA projects that domestic natural gas production will increase from 20.5 Tcf per year to 23.5 Tcf per year between 2008 and 2028.

PROPERTIES

Our assets consist of nine gathering systems, six natural gas treating facilities, two gas processing facilities and one interstate pipeline. Our assets are located in East and West Texas, the Rocky Mountains (Utah and Wyoming), and the Mid-Continent (Kansas and Oklahoma).

In the areas in which we operate there historically has been a significant level of drilling activity offsetting the natural decline in production from existing wells. The current commodity price environment has resulted in significantly lower drilling

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activity in recent months throughout the areas in which we operate. We have no control over this activity. In addition, the recent or further decline in commodity prices could affect production rates and the level of investment by Anadarko and third parties in the exploration for and development of new natural gas reserves. Further, Anadarko and our third-party customers plan to reduce, and may temporarily suspend, drilling activities in certain areas during 2009, which would limit the number of new wells connected to our systems. For example, Anadarko has announced that it expects to reduce its onshore rig fleet by approximately 50% from peak levels reached in 2008 until further cost reductions are realized, although the specific rig activity in our areas of operations has not been announced. Anadarko s and our third-party customers 2009 capital programs and drilling activity are subject to change based on their continued monitoring of industry economic conditions and the commodity price environment. The current commodity price environment may impact the comparability of our historical operating results to future operating results.

The following sections describe in more detail the services provided by our assets in our areas of operation. All volumes stated below are based on a standard pressure base of 14.73 psia.

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The following map depicts the Partnership s and Anadarko s significant midstream assets as of December 31, 2008.

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East Texas
Dew gathering system
General. The 320-mile Dew gathering system is located in Anderson, Freestone, Leon and Robertson Counties of East Texas. The Dew gathering system was placed into service in November 1998 to provide gathering services for Anadarko s drilling program in the Bossier play. The system provides gathering, dehydration and compression services and ultimately delivers into the Pinnacle gas treating system for any required treating.
Average throughput on the Dew gathering system for the years ended December 31, 2008, 2007 and 2006 was 200 MMcf/d, 218 MMcf/d and 232 MMcf/d, respectively, from approximately 745, 730 and 700 receipt points, respectively. The Dew gathering system has pipeline diameters ranging from three to twelve inches and has 11 compressor stations with a combined 43,167 horsepower of compression.
Customers. Anadarko is the largest shipper on the Dew gathering system. Anadarko s equity gas accounted for 196 MMcf/d of throughput during the year ended December 31, 2008, which represented approximately 98% of the total volume on the system.
Delivery Points. The Dew gathering system has delivery points with Pinnacle Gas Treating LLC, which is the primary delivery point and is described in more detail below, and Kinder Morgan s Tejas pipeline.
Supply. Anadarko has approximately 879 producing wells in the Bossier play and controls approximately 238,000 gross acres in the area. Anadarko historically has maintained an active drilling program in the Bossier play, drilling approximately 20 to 30 gross wells per year.
Pinnacle Gas Treating LLC
General. Pinnacle Gas Treating LLC, or PGT, includes our Pinnacle gathering system and our Bethel treating plant. PGT provides sour gas gathering and treating service in Anderson, Freestone, Leon, Limestone and Robertson Counties of East Texas. The gathering system consists of 267 miles of pipeline with diameters ranging from three to 24 inches and one compressor station with 1,265 horsepower. The Bethel treating plant, located in Anderson County, has total CO_2 treating capacity of 500 MMcf/d and 20 LTD of sulfur treating capacity.
Average throughput on the Pinnacle gathering system for the years ended December 31, 2008, 2007 and 2006 was 260 MMcf/d, 296 MMcf/d and 306 MMcf/d, respectively, from approximately 74, 70 and 60 receipt points, respectively.
Customers. Anadarko is the largest shipper on the Pinnacle gathering system with 234 MMcf/d for the year ended December 31, 2008, which represented approximately 90% of the total throughput on the system during such period. The balance of throughput on the system during 2008 was primarily from five third-party shippers.
Delivery Points. The Pinnacle gathering system is connected to Enterprise Texas Pipeline, LP s pipeline, the Energy Transfer Fuels pipeline, the ETC Texas pipeline, Kinder Morgan s Tejas pipeline, the ATMOS Texas pipeline and the Enbridge Pipelines (East Texas) LP pipeline. These pipelines provide transportation to the Carthage, Waha and Houston Ship Channel market hubs in Texas.
Supply. The Pinnacle gathering system is well positioned to provide gathering and treating services to the five-county area over which it extends. With the recent drilling activity in the Cotton Valley Lime formations, which contain higher concentrations of H_2S and CO_2, we obtained a commitment from a third-party producer that allowed us to expand the Bethel treating facilities during 2008 by installing an additional 11 LTD of sulfur treating capacity to bring the total installed sulfur treating capacity to 20 LTD. With this expansion, we believe that we are well positioned to benefit from future sour gas production in the area.
Rocky Mountains
MIGC system
General. The MIGC system is a 264-mile interstate pipeline operating within the Powder River Basin of Wyoming that is regulated by FERC. The MIGC system traverses the Powder River Basin from north to south, extending approximately 150 miles to Glenrock, Wyoming. As a result, the MIGC system is well positioned to provide transportation for the extensive

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natural gas volumes received from various coal-bed methane gathering systems and conventional gas processing plants throughout the Powder River Basin. MIGC offers both forward-haul and backhaul transportation services, and additional capacity is available from time to time on an interruptible basis.

During September 2007, MIGC completed the installation of, and placed into service, the Python compression station, which increased capacity on the MIGC system by approximately 50 MMcf/d. MIGC is currently certificated for 175 MMcf/d of firm transportation capacity, all of which is fully subscribed.

Average throughput on the MIGC system for the years ended December 31, 2008, 2007 and 2006 was 171 MMcf/d, 148 MMcf/d and 126 MMcf/d, respectively, from approximately 20 receipt points.

Customers. Anadarko is the largest firm shipper on the MIGC system, with approximately 72% of throughput for the year ended December 31, 2008. For the year ended December 31, 2008, two third-party shippers accounted for approximately 27% of throughput on the system.

Revenues on the MIGC system are generated from contract demand charges and volumetric fees paid by shippers under firm and interruptible gas transportation agreements. Our current firm transportation agreements range in term from approximately one to 10 years. Of the current certificated capacity of 175 MMcf/d, 85 MMcf/d is contracted through January 2011, 45 MMcf/d is contracted through September 2012 and 40 MMcf/d is contracted through October 2018. Most of our interruptible gas transportation agreements are month-to-month with the remainder generally having terms of less than one year. Approximately 92% of our revenues from the MIGC system for the year ended December 31, 2008 were associated with firm transportation demand charges.

Delivery Points. MIGC volumes can be redelivered to four interstate market pipelines and one intrastate pipeline, including the Williston Basin Interstate pipeline at the northern end of the Powder River Basin, the MGTC intrastate pipeline, a pipeline that supplies local markets in Wyoming, the Wyoming Interstate Company s Medicine Bow lateral pipeline, the Colorado Interstate Gas pipeline and the Kinder Morgan interstate pipeline at the southern end of the Powder River Basin near Glenrock, Wyoming. The MGTC pipeline is owned by Anadarko.

Supply. Anadarko has a working interest in over 1.4 million gross acres within the prolific Powder River Basin. It currently operates approximately 4,400 gross producing coal-bed methane wells and has non-operating interests in more than 5,300 additional gross producing coal-bed methane wells. Anadarko s gross acreage is approximately 50% developed with substantial undeveloped acreage positions in the expanding Big George coal play and the multiple seam coal fairway to the north of the Big George play.

Fort Union system

General. The Fort Union system is a gathering system operating within the Powder River Basin of Wyoming, starting in west central Campbell County and terminating at the Medicine Bow treating plant. The Fort Union gathering system has three parallel 24-inch pipes, each 106 miles in length, and includes CO_2 treating facilities at the Medicine Bow plant. The plant currently consists of two amine trains and an additional train is expected to be placed into service during the first quarter of 2009.

Fort Union Gas Gathering, L.L.C. is a partnership among Copano Pipelines/Rocky Mountains, LLC (37.04%), Crestone Powder River L.L.C. (37.04%), Bargath, Inc. (11.11%) and the Partnership (14.81%). Anadarko is the field and construction operator of the Fort Union gathering system. The Fort Union gathering system has a capacity of approximately 1.3 Bcf/d.

Average throughput on the Fort Union system for the years ended December 31, 2008, 2007 and 2006 was 754 MMcf/d, 566 MMcf/d and 521 MMcf/d, respectively, from approximately 15 receipt points.

Customers. The four Fort Union owners named above are the only firm shippers on the Fort Union system. To the extent capacity on the system is not used by the owners, it is available to third parties under interruptible agreements.

Delivery Points. The Fort Union system delivers coal-bed methane gas to the Glenrock, Wyoming Hub which accesses interstate pipelines, including Wyoming Interstate Gas Company, Kinder Morgan Interstate Gas Transportation Company and Colorado Interstate Gas Company. These interstate pipelines serve gas markets in the Rocky Mountains and Midwest regions of the United States.

Supply. Substantially all of Fort Union s gas supply is comprised of coal-bed methane volumes that are either produced or gathered by the four Fort Union owners throughout the Powder River Basin. Anadarko has a working interest in over 1.4

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million gross acres within the Powder River Basin and currently produces gas from approximately 9,800 coal-bed methane wells in the Wyodek coal, the expanding Big George coal play and the multiple seam coal fairway to the north of the Big George play. Another of the Fort Union owners has a comparable working interest in approximately 80% of Anadarko s producing coal-bed methane wells. The two remaining Fort Union owners gather gas for delivery to Fort Union under contracts with acreage dedications from multiple producers in the heart of the Basin and from the coal-bed methane producing area near Sheridan, Wyoming.

Helper gathering system

General. The 67-mile Helper gathering system, located in Carbon County, Utah, was built to provide gathering services for Anadarko s coal-bed methane development of the Ferron Coal. The Helper gathering system provides gathering, dehydration, compression and treating services for coal-bed methane gas.

Average throughput on the Helper gathering system for the years ended December 31, 2008, 2007 and 2006 was 36 MMcf/d, 35 MMcf/d and 38 MMcf/d, respectively, from approximately 120 receipt points. The Helper gathering system has pipeline diameters ranging from four to 20 inches and includes two compressor stations with a combined 14,075 horsepower and two CO_2 treating facilities.

Customers. Anadarko is the largest shipper on the Helper gathering system. For the year ended December 31, 2008, Anadarko s equity production represented approximately 99% of the Helper gathering system s volume.

Delivery Points. The Helper gathering system delivers into the Questar Transportation Services Company s pipeline. Questar provides transportation to regional markets in Wyoming, Colorado and Utah and also delivers into the Kern River Pipeline, which provides transportation to markets in the western U.S., primarily California.

Supply. The Helper Field is an Anadarko-operated field on the southwestern edge of the Uintah Basin that produces from the Cretaceous Ferron sands and coals. The Helper Field consists of approximately 19,000 gross acres and has 116 gross producing wells as of December 31, 2008. Cardinal Draw, which lies immediately to the east of Helper Field, has 36 gross producing wells as of December 31, 2008 and covers approximately 19,000 gross acres.

Clawson gathering system

General. The 47-mile Clawson gathering system, located in Carbon and Emery Counties of Utah, was built in 2001 to provide gathering services for Anadarko s coal-bed methane development of the Ferron Coal. The Clawson gathering system provides gathering, dehydration, compression and treating services for coal-bed methane gas.

Average throughput on the Clawson gathering system for the years ended December 31, 2008, 2007 and 2006 was 17 MMcf/d, 18 MMcf/d and 22 MMcf/d, respectively, from approximately 45 receipt points. The Clawson gathering system has pipeline diameters ranging from four to 18 inches and includes one compressor station, with 6,310 horsepower, and a CO_2 treating facility.

Customers. Anadarko is the largest shipper on the Clawson gathering system with approximately 97% of the total throughput delivered into the system during the year ended December 31, 2008. The remaining throughput on the system was comprised of production from third-party producers.

Delivery Points. The Clawson gathering system delivers into Questar Transportation Services Company s pipeline.

Supply. Clawson Springs Field has 45 gross producing wells as of December 31, 2008 on approximately 7,000 gross acres. Production for Clawson Springs is primarily from the Cretaceous Ferron sands and coals.

Hilight gathering system and processing plant

General. The 980-mile Hilight gathering system, located in Johnson, Campbell, Natrona and Converse Counties of Wyoming, was built to provide low- and high-pressure gathering services for area conventional gas production and delivers to the Hilight plant for processing. The Hilight gathering system has pipeline diameters ranging from three to 16 inches and includes 10 compressor stations with 16,366 horsepower. The Hilight system was built in 1969 and has a capacity of approximately 30 MMcf/d. The Hilight plant utilizes a refrigeration process and provides for fractionation of the recovered NGL product into propane, butanes and natural gasoline.

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Average throughput on the Hilight system for the years ended December 31, 2008, 2007 and 2006 was 28 MMcf/d, 28 MMcf/d and 29 MMcf/d, respectively, from approximately 400 receipt points.

Customers. Gas processed at the Hilight system is purchased from 48 third-party customers, with the ten largest producers providing approximately 80% of the system throughput.

Delivery Points. The Hilight gathering system delivers into MIGC s 16-inch transmission line, which delivers to Glenrock, Wyoming.

Supply. The Hilight gathering system serves the gas gathering needs of several conventional producing fields in Johnson, Campbell, Natrona and Converse counties. Our customers have historically and may continue to maintain throughput with workover activity and by developing new prospects. Based on publicly available information, these producers are planning drilling activity over the next three to five years in the area serviced by the system.

Newcastle gathering system and processing plant

General. The 150-mile Newcastle gathering system, located in Weston and Niobrara Counties of Wyoming, was built to provide gathering services for conventional gas production in the area. The gathering system delivers into the Newcastle plant, which was built in 1981 and has a capacity of approximately 3 MMcf/d. The plant utilizes a refrigeration process and provides for fractionation of the recovered NGL product into propane and butane/gasoline mix products. The Newcastle facility is a joint venture among Black Hills Exploration and Production, Inc. (44.7%), John Paulson (5.3%) and the Partnership (50.0%). The Newcastle gathering system has pipeline diameters ranging from two to six inches and includes one compressor station, with 560 horsepower. The Newcastle plant has an additional 2,100 horsepower for refrigeration and residue compression.

Average throughput on the Newcastle system for the years ended December 31, 2008, 2007 and 2006 was 1 MMcf/d, 2 MMcf/d and 2 MMcf/d, respectively, from approximately 400 receipt points.

Customers. Gas processed at the Newcastle system is purchased from 15 third-party customers, with the largest three producers providing approximately 85% of the system throughput. The largest producer, Black Hills Exploration, provides approximately 70% of the throughput and is a part owner of the Newcastle system.

Delivery Points. Propane products from the Newcastle plant are typically sold locally by truck and the butane/gasoline mix products are transported to the Hilight plant for further fractionation. Residue gas from the Newcastle system is delivered into MGTC s pipeline for transport, distribution and sales.

Supply. The Newcastle gathering system and plant primarily service gas production from the Clareton and Finn-Shurley fields in Weston County. Due to infill drilling and enhanced production techniques, producers have continued to maintain and improve production. It is estimated that, after 28 years of development, approximately 9% of the original reserves in place have been produced.

Mid-Continent

Hugoton gathering system

General. The 2,073-mile Hugoton gathering system provides gathering service to the Hugoton field and is primarily located in Seward, Stevens, Grant and Morton Counties of Southwest Kansas and Texas County in Oklahoma.

Average throughput on the Hugoton gathering system for the years ended December 31, 2008, 2007 and 2006 was 131 MMcf/d, 123 MMcf/d and 114 MMcf/d, respectively, from approximately 1,550 receipt points. The Hugoton gathering system has pipeline diameters ranging from two to 26 inches and 43 compressor stations with a combined 102,257 horsepower of compression.

Customers. Anadarko is the largest customer on the Hugoton gathering system with 105 MMcf/d of average throughput during the year ended December 31, 2008, representing 83% of the total volume on the system. Of these volumes, 65% represents Anadarko s equity production and 35% represents volumes purchased by Anadarko primarily from two third parties. Approximately 17% of the remaining throughput on the Hugoton system for the year ended December 31, 2008 was from four other third-party shippers.

Delivery Points. The Hugoton gathering system is connected to DCP Midstream, LP s National Helium plant, which extracts NGLs and helium and redelivers residue gas into the Panhandle Eastern pipeline. The system is also connected to Pioneer Natural Resources Corporation s Satanta plant for NGL processing and to the adjacent Mid-Continent Market Center, which provides access to the Panhandle Eastern pipeline, the Northern Natural Gas pipeline, the Natural Gas pipeline, the Southern Star pipeline, and the ANR pipeline. These pipelines provide transportation and market access to Midwestern and Northeastern markets.

Supply. The Hugoton field is one of the largest natural gas fields in North America. The Hugoton field continues to be a long-life, slow-decline asset for Anadarko, which operates over 1,200 gross wells in the area and has an extensive acreage position with approximately 470,000 gross acres. We believe that recent changes to the Hugoton and Panoma Council Grove Proration Orders will provide opportunities for significant recompletion, redrilling and density-drilling activities.

By virtue of a farmout agreement between a third-party producer and Anadarko, the third-party producer gained the right to explore below the primary formations in the Hugoton field. We believe our existing asset is well-positioned to gather volumes that may be produced from new wells the third-party producer may successfully drill.

West Texas

Haley gathering system

General. The 108-mile Haley gathering system is located in Loving County, Texas and gathers Anadarko s production from the Delaware Basin. The Haley gathering system provides gathering and dehydration services and has pipeline diameters ranging from four to 16 inches.

Average throughput on the Haley gathering system for the years ended December 31, 2008, 2007 and 2006 was 152 MMcf/d, 169 MMcf/d and 133 MMcf/d, respectively, from approximately 75, 60 and 35 receipt points, respectively. The Haley gathering system has historically experienced rapid growth as a result of Anadarko s successful drilling activity in the area.

Customers. Anadarko s and its partners production represented 99% of the Haley gathering system s throughput for the year ended December 31, 2008.

Delivery Points. The Haley gathering system has multiple delivery points. The primary delivery points are to the El Paso Natural Gas pipeline or the Enterprise GC, L.P. pipeline for ultimate delivery into Energy Transfer s Oasis pipeline. We also have the ability to deliver into Southern Union Energy Services pipeline for further delivery into the Oasis pipeline. The pipelines at these delivery points provide transportation to both the Waha and Houston Ship Channel Markets.

Supply. In the greater Delaware basin, Anadarko had interests in 159 gross producing wells as of December 31, 2008 and access to approximately 545,000 gross acres.

COMPETITION

We do not currently face significant competition on the majority of our systems due to the substantial throughput volumes being owned or controlled by Anadarko and its dedication to us of future production from acreage surrounding our gathering systems. We believe our assets that are outside of the dedicated areas are geographically well positioned to retain and attract third-party volumes.

Competition on gathering systems and at processing plants

The natural gas gathering, compression, processing, treating and transportation business is very competitive. Our competitors include other midstream companies, producers, and intrastate and interstate pipelines. Competition for natural gas volumes is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies. We believe the primary competitive advantages of our Hilight and Newcastle systems, which gather and process third-party volumes, are their proximity to established and new production and our ability to provide flexible services to producers, including gathering, compression and processing. We believe we can provide the services that producers and other customers require to connect, gather and process their natural gas efficiently, at competitive and flexible contract terms. Further, we believe that Fort Union s centralized amine treating facility provides Fort Union a competitive advantage.

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Our primary competitors for our gathering systems and processing plants include:

Dew gathering system and Pinnacle gas treating: ETC Texas Pipeline, Ltd., Enbridge Pipelines (East Texas) LP, XTO Energy and Kinder Morgan Tejas Pipeline, LP.

Fort Union: Thunder Creek Gas Services

Helper and Clawson gathering systems: Questar Transportation Services Company.

Hilight gathering and processing system: DCP Midstream and Merit Energy.

Hugoton gathering system: ONEOK Gas Gathering Company, DCP Midstream, LP and Pioneer Resources.

Haley gathering system: Enterprise GC, LP and Southern Union Energy Services Company.

Newcastle gathering and processing system: DCP Midstream.

Competition on transportation system

MIGC competes with other pipelines that service the regional market and transport gas volumes from the Powder River Basin to Glenrock, Wyoming. MIGC competitors seek to attract and connect new gas volumes throughout the Powder River Basin, including certain of the volumes currently being transported on MIGC. An increase in competition could result from new pipeline installations or expansions by existing pipelines. Competitive factors include commercial terms, available capacity, fuel efficiencies, the interconnected pipelines and gas quality issues. MIGC s major competitor is Thunder Creek Gas Services.

SAFETY AND MAINTENANCE

We are subject to regulation by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, of the Department of Transportation, or the DOT, pursuant to the Natural Gas Pipeline Safety Act of 1968, or the NGPSA, and the Pipeline Safety Improvement Act of 2002, or the PSIA, which was recently reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transportation pipelines and some gathering lines in high-consequence areas. The PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in high consequence areas, such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. Our transportation pipeline system, MIGC, includes no high consequence areas and thus these particular integrity management programs are not applicable.

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

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. 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 addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or 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 concerning hazardous materials used or produced in our operations and that such 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 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

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excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling points 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 all applicable laws and regulations relating to worker health and safety.

REGULATION OF OPERATIONS

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Interstate transportation pipeline regulation

MIGC, our interstate natural gas transportation system, is subject to regulation by FERC under the Natural Gas Act of 1938, or the NGA.

Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation extends to such matters as:

- rates, services, and terms and conditions of service;
- the types of services MIGC may offer to its customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas; and
- participation by interstate pipelines in cash management arrangements.

Natural gas companies are prohibited from charging rates that have been determined not to be just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenues associated with providing transportation service.

Commencing in 2003, 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 and certain natural gas storage companies that provide storage services in interstate commerce. Order No. 2004 became effective in 2004. Among other matters, Order No. 2004 required interstate pipeline and storage companies to operate independently from their energy affiliates, prohibited interstate pipeline and storage companies from providing non-public transportation or shipper information to their energy affiliates, prohibited interstate pipeline and storage companies from favoring their energy affiliates in providing service, and obligated interstate pipeline and storage companies to post on their websites a number of items of information concerning the company, including its organizational structure, facilities shared with energy affiliates, discounts given for services and instances in which the company has agreed to waive discretionary terms of its tariff. On July 7, 2004, FERC issued an order providing MIGC with a partial waiver of the independent functioning and information access provisions of the standards of conduct.

Late in 2006, the D.C. Circuit vacated and remanded Order No. 2004 as it relates to natural gas transportation providers, including MIGC. The D.C. Circuit found that FERC had not adequately justified its expansion of the prior standards of conduct to include energy affiliates, and vacated the entire rule as it relates to natural gas transportation providers. On January 9, 2007, as clarified on March 21, 2007, FERC issued an interim rule (Order No. 690) re-promulgating on an interim basis the standards of conduct that were not challenged before the court, while FERC decided how to respond to the court s decision on a permanent basis through FERC s rulemaking process. On October 16, 2008, FERC issued Order No. 717, a final rule that amends the regulations adopted on an interim basis in Order No. 690. Order No. 717 implements revised standards of conduct that include three primary rules: (1) the independent functioning rule, which requires transmission function and marketing function employees to operate independently of each other; (2) the no-conduit rule, which prohibits passing transmission function information to marketing function employees; and (3) the transparency rule, which imposes posting requirements to help detect any instances of undue preference. FERC also clarified in Order No. 717 that existing waivers to the standards of conduct (such as those held by MIGC) shall continue in full force and effect. A number of parties have requested clarification or rehearing of Order No. 717, and FERC action on rehearing is currently pending. We have no way to predict what revisions to the standards of conduct may be made by FERC on rehearing. However, we do not expect the impact on MIGC to materially differ from the impact on other similarly situated natural gas service providers.

In May 2005, FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass-through partnership entity, if the pipeline proves that the ultimate owner of its equity interests has an actual or potential income tax liability on public utility income. The policy statement also provides that whether a pipeline s owners have such actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. In August 2005, FERC dismissed requests for rehearing of its new policy statement. On December 16, 2005, FERC issued its first significant case-specific review of the income tax allowance issue in a pipeline partnership s rate case. FERC reaffirmed its new income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16, 2005 order were appealed to the D.C. Circuit. The D.C. Circuit issued an order on May 29, 2007 in which it denied these appeals and upheld FERC s new tax allowance policy and the application of that policy in the December 16, 2005 order on all points subject to appeal. The D.C. Circuit denied rehearing of the May 29, 2007 decision on August 20, 2007, and the D.C. Circuit s decision is final. On December 8, 2006, FERC issued another order addressing the income tax allowance in rates. In the December 8, 2006 order, FERC refined and reaffirmed prior statements regarding its income tax allowance policy, and notably raised a new issue regarding the implication of the policy statement for publicly traded partnerships. It noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which FERC characterized as a tax savings. FERC stated that it is concerned that this created an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, FERC chose to adjust the pipeline s equity rate of return downward based on the percentage by which the publicly traded partnership s cash flow exceeded taxable income. On February 7, 2007, the pipeline filed a request for rehearing on this issue. FERC issued an order on rehearing of the December 8, 2006 order on May 2, 2008, establishing a paper hearing on certain issues and determining that the remaining issues not addressed in the paper hearing would be addressed in an order following the completion of the paper hearing. Rehearing of the May 2, 2008 order has been granted and is currently pending. A partial offer of settlement of the issues subject to the paper hearing has been filed, and FERC action on the partial settlement is currently pending. The ultimate outcome of this proceeding cannot be predicted with certainty.

On April 17, 2008, FERC issued a proposed policy statement regarding the composition of proxy groups for determining the appropriate return on equity for natural gas and oil pipelines using FERC s Discounted Cash Flow, or DCF, model. In the policy statement, which modified a proposed policy statement issued in July 2007, FERC concluded: (1) master limited partnerships, or MLPs, should be included in the proxy group used to determine return on equity for both oil and natural gas pipelines; (2) there should be no cap on the level of distributions included in FERC s current DCF methodology; (3) Institutional Brokers Estimate System, or IBES, forecasts should remain the basis for the short-term growth forecast used in the DCF calculation; (4) the long-term growth component of the DCF model should be limited to fifty percent of long-term gross domestic product; and (5) there should be no modification to the current two-thirds and one-third weighting of the short-term and long-term growth components, respectively. FERC also concluded that the policy statement should govern all gas and oil rate proceedings involving the establishment of return on equity that are pending before FERC. FERC s policy determinations applicable to MLPs are subject to further modification, and it is possible that these policy determinations may have a negative impact on

MIGC s rates in the future.

On August 8, 2005, Congress enacted the Energy Policy Act of 2005, or the EPAct 2005. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC: (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a nexus to jurisdictional transactions. EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978, or NGPA, to give FERC authority to impose civil penalties for violations of these statutes, up to $1,000,000 per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

In 2008, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. Order No. 704, as clarified on rehearing in 2008, requires buyers and sellers of natural gas above a de minimis level, including entities not otherwise subject to FERC jurisdiction, to submit an annual report to FERC describing their wholesale physical natural gas transactions. The first such report is due on May 1, 2009 for calendar year 2008 activities. Order No. 720, issued on November 20, 2008, increases the Internet posting obligations of interstate pipelines, and also requires major non-interstate pipelines (defined as pipelines with annual deliveries of more than 50 million MMBtu) to post on the Internet the daily volumes scheduled for each receipt and delivery point on their systems with a design capacity of 15,000 MMBtu per day or greater. Numerous parties have requested modification or reconsideration of this rule, and it remains to be seen whether the requirements will be modified on rehearing, which is currently pending. In November 2008, FERC also issued a Notice of Inquiry to the industry soliciting comments regarding whether Hinshaw pipelines and intrastate pipelines that transport natural gas in interstate commerce pursuant to Section 311 of the NGPA should be required to post on the Internet certain details of their transactions with individual shippers in a manner comparable to the reporting requirements applicable to interstate pipelines. Once FERC evaluates the comments filed in response to the Notice of Inquiry, it may choose to engage in the formal rulemaking process to propose additional reporting requirements on such pipelines.

In 2008, FERC also took action to ease restrictions on the capacity release market, in which shippers on interstate pipelines can transfer to one another their rights to pipeline and/or storage capacity. Among other things, Order No. 712, as modified on rehearing, removes the price ceiling on short-term capacity releases of one year or less, allows a shipper releasing gas storage capacity to tie the release to the purchase of the gas inventory and the obligation to deliver the same volume at the expiration of the release, and facilitates Asset Management Agreements, or AMAs, by exempting releases under qualified AMAs from: the competitive bidding requirements for released capacity; FERC s prohibition against tying releases to extraneous conditions; and the prohibition on capacity brokering.

Gathering pipeline regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that our natural gas pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Our natural gas gathering operations are subject to ratable take and common purchaser statutes in most of the states in which we operate. These statutes generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. To date, there has been no adverse effect to our systems due to these regulations.

During the 2007 legislative session, the Texas State Legislature passed H.B. 3273, or the Competition Bill, and H.B. 1920, or the LUG Bill. The Texas Competition Bill and LUG Bill contain provisions applicable to gathering facilities. The Competition Bill allows the Railroad Commission of Texas, or the TRRC, the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering in formal rate proceedings. It also gives the TRRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters and gatherers for taking discriminatory actions against shippers and sellers. The LUG Bill modifies the informal complaint process at the TRRC with procedures unique to lost and unaccounted for gas issues. It extends the types of information that can be requested and gives the TRRC the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007. We cannot predict what effect, if any, either the Competition Bill or the LUG Bill might have on our gathering operations.

ENVIRONMENTAL MATTERS

General

Our operation of pipelines, plants and other facilities for the gathering, processing, compression, treating and transporting of natural gas and other products is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- requiring investigatory and remedial actions to mitigate or eliminate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed to be in non-compliance with such environmental laws and regulations and permits issued pursuant thereto.

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

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations or cash flows. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, process, compress, treat and transport natural gas. We cannot assure you, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of several of the material environmental laws and regulations that relate to our business. We believe that we are in material compliance with applicable environmental laws and regulations.

Hazardous substances and waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and joint and several liability for the investigation and remediation of affected areas where hazardous substances 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. These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release, 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 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 the costs they incur from the responsible classes of persons. 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), which 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, which are subject to the requirements of the Resource Conservation and Recovery Act, referred to as RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA s hazardous waste regulations. 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, be subject to more rigorous and costly disposal requirements. 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 generally 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 the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and other wastes was not under our control. These properties and the 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 not currently aware of any facts, events or conditions relating to such requirements that could materially impact our financial condition, results of operations or cash flows.

Air emissions

Our operations are subject to the Federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We believe that we are in material compliance with these requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Water discharges

The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants or fill into state waters as well as waters of the U.S. and adjacent wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of permits issued by the EPA, the Army Corps of Engineers or an analogous state agency. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe that we are in material compliance with these requirements. However, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. 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, results of operations or cash flows.

Endangered species

The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Climate change

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, numerous states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas initiatives. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA,* 549 U.S. 497 (2007), the EPA may be required or encouraged to regulate greenhouse gas emissions from mobile sources (*e.g*., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts* that greenhouse gases fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we conduct business could adversely affect our operations and demand for our services.

Anti-terrorism measures

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present high levels of security risk. The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on November 20, 2007, further issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. We have determined the extent to which our facilities are subject to the rule, made the necessary notifications and determined that the requirements will not have a material impact on our financial condition, results of operations or cash flows.

TITLE TO PROPERTIES AND RIGHTS-OF-WAY

Our real property is classified into two categories: (1) parcels that we own in fee 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

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such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. We have or our Predecessor has leased or owned these lands 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 leasehold estates or fee ownership of such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit 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, rights-of-way, permits and licenses.

Some of the leases, easements, rights-of-way, permits and licenses transferred to us at the time of our initial public offering required the consent of the grantor of such rights, which in certain instances is a governmental entity. Our general partner has obtained sufficient third-party consents, permits and authorizations for the transfer of the assets necessary to enable us to operate our business in all material respects. With respect to any remaining consents, permits or authorizations that have not been obtained, we have determined these will not have material adverse effect on the operation of our business should we fail to obtain such consents, permits or authorization in a reasonable time frame. Anadarko holds record title to portions of certain assets as we make the appropriate filings in the jurisdictions in which such assets are located and obtain any consents and approvals as needed. Such consents and approvals would include those required by federal and state agencies or other political subdivisions. In some cases, Anadarko temporarily holds record title to property as nominee for our benefit and in other cases may, on the basis of expense and difficulty associated with the conveyance of title, may cause its affiliates to retain title, as nominee for our benefit, until a future date. We anticipate that there will be no material change in the tax treatment of our common units resulting from Anadarko holding the title to any part of such assets subject to future conveyance or as our nominee.

EMPLOYEES

We do not have any employees. The officers of our general partner manage our operations and activities. As of December 31, 2008, Anadarko employed approximately 167 people who provided direct, full-time support to our operations. All of the employees required to conduct and support our operations are employed by Anadarko and all of our direct, full-time personnel are subject to a service and secondment agreement between our general partner and Anadarko. None of these employees are covered by collective bargaining agreements, and Anadarko considers its employee relations to be good.

Item 1A. *Risk Factors*

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

We have made in this report, and may from time to time otherwise make in other public filings, press releases and discussions, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 concerning our operations, economic performance and financial condition. These statements can be identified by the use of forward-looking terminology such as may, could, believe, expect, anticipate, estimate, project, continue, potential, plan, forecast or other similar words. These st discuss future expectations, contain projections of results of operations or financial condition or include other forward-looking information. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- *our assumptions about the energy market;*
- *future treating and processing volumes and pipeline throughput, including Anadarko s production, which is gathered or transported through our assets;*
- *operating results;*
- *competitive conditions;*

technology;

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the availability of capital resources, capital expenditures and other contractual obligations;

the supply of and demand for, and the price of oil, natural gas, NGLs and other products or services;

the weather;

inflation;

the availability of goods and services;

general economic conditions, either internationally or nationally or in the jurisdictions in which we are doing business;

legislative or regulatory changes, including changes in environmental regulation, environmental risks, regulations by FERC and liability under federal and state environmental laws and regulations;

the securities or capital markets, and our ability to access credit, including under Anadarko s $1.3 billion credit facility;

our ability to maintain and/or obtain rights to operate our assets on land owned by third parties;

our ability to acquire assets on acceptable terms;

non-payment or non-performance of Anadarko or other significant customers, including under our gathering, processing and transportation agreements and our $260.0 million note receivable from Anadarko; and

other factors discussed below and elsewhere in Item 1A Risk Factors and in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates included in this Form 10-K and in our other public filings and press releases.

The risk factors and other factors noted throughout or incorporated by reference in this report could cause our actual results to differ materially from those contained in any forward-looking statement. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Limited partner units are inherently different from 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 similar businesses. We urge you to carefully consider the following risk factors together with all of the other information included in this annual report in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition or results of operation could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment in us.

RISKS RELATED TO OUR BUSINESS

We are dependent on Anadarko for a majority of the natural gas that we gather, treat and transport. A material reduction in Anadarko s production gathered or transported by our assets would result in a material decline in our revenues and cash available for distribution.

We rely on Anadarko for a majority of the natural gas that we gather, treat and transport. For the year ended December 31, 2008, Anadarko accounted for approximately 83% of our natural gas gathering, processing and transportation volumes. Anadarko may suffer a decrease in production volumes in the areas serviced by us and is under no contractual obligation to maintain its production volumes dedicated to us. The loss of a significant portion of the natural gas volumes supplied by Anadarko would result in a material decline in our revenues and our cash available for distribution. In addition, Anadarko may reduce its drilling activity in our areas of operation or determine that drilling activity in other areas of operation is strategically more attractive. A shift in Anadarko s focus away from our areas of operation could result in reduced throughput on our system and a material decline in our revenues and cash available for distribution.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of natural gas, which is dependent on certain factors beyond our control. Any decrease in the volumes of natural gas that we gather, process, compress, treat and transport could adversely affect our business and operating results.

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The volumes that support our business are dependent on the level of production from natural gas wells connected to our gathering systems and processing and treatment facilities. This production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering systems, we must obtain new sources of natural gas. The primary factors affecting our ability to obtain sources of natural gas include (i) the level of successful drilling activity near our systems, (ii) our ability to compete for volumes from successful new wells, to the extent such wells are not dedicated to our systems, and (iii) our ability to capture volumes currently gathered or processed by third parties.

While Anadarko has dedicated production from certain of its properties to us, we have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our gathering systems or the rate at which production from a well declines. In addition, we have no control over Anadarko or other producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, prevailing and projected commodity prices, demand for hydrocarbons, levels of reserves, geological considerations, governmental regulations, the availability of drilling rigs and other production and development costs. Fluctuations in commodity prices can also greatly affect investments by Anadarko and third parties in the development of new natural gas reserves. Declines in natural gas prices could have a negative impact on exploration, development and production activity and, if sustained, could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our gathering and treating assets.

Because of these factors, even if new natural gas reserves are known to exist in areas served by our assets, producers (including Anadarko) may choose not to develop those reserves. Moreover, Anadarko may not develop the acreage it has dedicated to us. If competition or reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, it could reduce our revenue and impair our ability to make cash distributions to our unitholders.

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the minimum quarterly distribution to holders of our common and subordinated units.

In order to pay the minimum quarterly distribution of $0.30 per unit per quarter, or $1.20 per unit per year, we will require available cash of approximately $17.0 million per quarter, or $68.1 million per year, based on the number of general partner units and common and subordinated units outstanding at December 31, 2008. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our 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 of, level of production of, and demand for natural gas;
- the volume of natural gas we gather, compress, treat, process and transport;
- the volumes and prices of condensate that we retain and sell;
- demand charges and volumetric fees associated with our transportation services;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance and general and administrative costs;
- regulatory action affecting the supply of or demand for natural gas, the rates we can charge, how we contract for services, our existing contracts, our operating costs or our operating flexibility; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in debt agreements to which we are a party; and
- the amount of cash reserves established by our general partner.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Recently, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market and a declining real estate market in the U.S. have contributed to increased economic uncertainty and diminished expectations for the global economy.

These factors, combined with volatile oil, natural gas and NGLs prices, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad continues to deteriorate, demand for petroleum products could continue to diminish and prices for oil, natural gas and NGLs could continue to decrease, which could reduce the throughput on our systems, affect our vendors , suppliers and customers ability to continue operations, and adversely impact our results of operations, liquidity and financial condition.

Lower natural gas and oil prices could adversely affect our business.

Lower natural gas and oil prices could impact natural gas and oil exploration and production activity levels and result in a decline in the production of natural gas and condensate, resulting in reduced throughput on our systems. Any such decline may cause our current or potential customers to delay drilling or shut in production. In addition, such a decline would reduce the amount of NGLs and condensate we retain and sell. As a result, lower natural gas prices could have an 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, oil, condensate, NGLs and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- worldwide economic conditions;
- weather conditions and seasonal trends;
- the levels of domestic production and consumer demand;
- the availability of imported liquefied natural gas, or LNG;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials such as in the Mid-Continent or Rocky Mountains;
- 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.

We may not be able to obtain funding, obtain funding on acceptable terms or obtain funding under Anadarko s $1.3 billion credit facility because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.

Global financial markets and economic conditions have been, and continue to be volatile. The debt and equity capital markets have been exceedingly distressed. These issues, along with significant write-offs in the financial services sector, the repricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult for some entities to obtain funding. In addition, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to the borrower s current debt and reduced, or in some cases, ceased to provide funding to borrowers. In addition, we may be unable to obtain adequate funding under Anadarko s $1.3 billion credit facility if (i) Anadarko s lending counterparties become unwilling or unable to meet their funding obligations, (ii) Anadarko has to draw down on its entire $1.3 billion credit facility in order to meet its own capital needs or (iii) the amount we may borrow under Anadarko s $1.3 billion credit facility is reduced for other reasons. Due to these factors, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to execute our business plans, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our financial condition, results of operations or cash flows.

Limitations on our access to capital may impair our ability to execute our growth strategy.

Our ability to raise capital for acquisitions and other capital expenditures depends upon periodic ready access to the capital markets. In the future, we intend to finance our acquisitions and, to a much lesser extent, expansions of our gathering systems, through access to public and private debt and equity offerings. If we are unable to access the capital markets, we may be unable to execute our strategy of growth through acquisitions and expansions.

The amount of cash we have available for distribution to holders of our common and subordinated units depends primarily on our cash flow rather than on our profitability; accordingly, we may be prevented from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow 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 for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

The amount of available cash we need to pay the minimum quarterly distribution on all of our units and the corresponding distribution on our general partner s 2.0% interest for four quarters is approximately $68.1 million.

We typically do not obtain independent evaluations of natural gas reserves connected to our gathering, processing and transportation systems; therefore, in the future, volumes of natural gas on our systems could be less than we anticipate.

We typically do not obtain independent evaluations of natural gas reserves connected to our systems. Accordingly, we do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our systems are less than we anticipate and we are unable to secure additional sources of natural gas, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

We compete with similar enterprises in our areas of operation. Our competitors may expand or construct gathering, processing, compression, treating or transportation systems that would create additional competition for the services we provide to our customers. In addition, our customers, including Anadarko, may develop their own gathering, compression, treating, processing or transportation systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flow could be adversely affected by the activities of our competitors and our customers. 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 our unitholders.

Our operating income could be affected by changes in commodity prices.

Under our gathering agreements, we retain and sell condensate, which falls out of the natural gas stream during the gathering process, and compensate shippers with a thermally equivalent volume of natural gas. Condensate sales comprised a nominal amount of our total revenues for the year ended December 31, 2008. The price we receive for our drip condensate correlates to the market price of oil. The relationship between natural gas prices and oil prices therefore affects the margin on our drip condensate sales. When natural gas prices are high relative to oil prices, the profit margin we realize on our drip condensate sales is low due to the higher value of natural gas. Correspondingly, when natural gas prices are low relative to oil prices, the profit margin is high.

Our strategies to reduce our exposure to changes in commodity prices may fail to protect us and could reduce our gross margin and cash flows.

We pursue various strategies to seek to reduce our exposure to adverse changes in the prices for natural gas and NGLs. These strategies will vary in scope based upon the level and volatility of natural gas and NGLs prices and other changing market conditions. Based on operating income for the year ended December 31, 2008, approximately 74% of our services are provided under long-term contracts with fee-based rates, which are not directly impacted by changes in commodity prices, and approximately 22% of our processing services are provided under percent-of-proceeds arrangements pursuant to which our revenues are directly correlated with the prices of natural gas and NGLs. We have entered into fixed-price swap agreements with Anadarko to manage the commodity price risk otherwise inherent in our percent-of-proceeds contracts. If we do not (or are unable to) effectively manage the commodity price risk associated with these contracts or are unable to replace the existing swap arrangements when they expire, our revenue will decline in periods marked by lower natural gas and NGLs prices. In addition, it is possible that the percentage of our services subject to percent-of-proceeds contracts may significantly increase as a result of future acquisitions, if any. Finally, future acquisitions may also result in our acquiring other commodity-price susceptible contracts, *e.g*., keep-whole arrangements, which could result in incremental commodity price exposure.

If third-party pipelines or other facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

Our natural gas gathering and transportation systems connect to other pipelines or facilities, the majority of which are owned by third parties. The continuing operation of such third-party pipelines or facilities is not within our control. If any of these pipelines or facilities becomes unable to transport natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

Our interstate natural gas transportation operations are subject to regulation by FERC, which could have an adverse impact on our ability to establish transportation rates that would allow us to earn a reasonable return on our investment, or even recover the full cost of operating our pipeline, thereby adversely impacting our ability to make distributions.

MIGC, our interstate natural gas transportation system, is subject to regulation by FERC under the Natural Gas Act of 1938, or the NGA, and the Energy Policy Act of 2005, or the EPAct 2005.

Under the NGA, FERC has the authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation extends to such matters as:

- rates, services and terms and conditions of service;
- the types of services MIGC may offer to its customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas; and
- participation by interstate pipelines in cash management arrangements.

Natural gas companies are prohibited from charging rates that have been determined to be not just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The rates and terms and conditions for our interstate pipeline services are set forth in a FERC-approved tariff. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenues associated with providing transportation service.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EPAct 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1,000,000 per day for each violation. FERC also has the power to order disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets, which could cause our revenues to decline and operating expenses to increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that our natural gas pipelines, other than MIGC, meet the traditional tests FERC has used to determine if a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial ongoing litigation and, over time, FERC policy concerning where to draw the line between activities it regulates and activities excluded from its regulation has changed. The classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels.

FERC regulation of MIGC, including the outcome of certain FERC proceedings on the appropriate treatment of tax allowances included in regulated rates and the appropriate return on equity, may reduce our transportation revenues, affect our ability to include certain costs in regulated rates and increase our costs of operations, and thus adversely affect our cash available for distribution.

FERC has certain proceedings pending, which concern the appropriate allowance for income taxes that may be included in cost-based rates for FERC-regulated pipelines owned by publicly traded partnerships that do not directly pay federal income tax. FERC issued a policy permitting such tax allowances in 2005. FERC s policy and its initial application in a specific case were upheld on appeal by the D.C. Circuit in May of 2007 and the D.C. Circuit s decision is final. In December 2006, FERC issued another order addressing the income tax allowance in rates, in which it reaffirmed prior statements regarding its income tax allowance policy, but raised a new issue regarding the implication of the policy statement for publicly traded partnerships. FERC noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, creating an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, FERC adjusted the equity rate of return of the pipeline at issue downward based on the percentage by which the publicly traded partnership s cash flow exceeded taxable income. Further procedures have been ordered in this proceeding and the proceeding is still pending before FERC.

FERC issued a policy statement on April 17, 2008, regarding the composition of proxy groups for purposes of determining natural gas and oil pipeline equity returns to be included in cost-of-service based rates. In the policy statement, FERC determined that MLPs should be included in the proxy group used to determine return on equity, and made various determinations on how the Discounted Cash Flow, or DCF, methodology should be applied for MLPs. FERC also concluded that the policy statement should govern all gas and oil rate proceedings involving the establishment of return on equity that are pending before FERC. FERC s application of the policy statement in individual pipeline proceedings is subject to challenge in those proceedings.

The ultimate outcome of these proceedings is not certain and may result in new policies being established at FERC applicable to MLPs. Any such policy developments may adversely affect the ability of MIGC to achieve a reasonable level of return or impose limits on its ability to include a full income tax allowance in cost of service, and therefore could adversely affect our cash available for distribution.

We are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.

Our natural gas gathering, compression, treating, processing and transportation operations are subject to stringent and complex federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection. Examples of these laws include:

- the federal Clean Air Act and analogous state laws that impose obligations related to air emissions;
- the federal Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or the Superfund law, and analogous state laws that require and regulate the cleanup of hazardous substances that have been released at properties currently or previously owned or operated by us or at locations to which our wastes are or have been transported for disposal;
- the federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;
- the federal Resource Conservation and Recovery Act, also known as RCRA, and analogous state laws that impose requirements for the storage, treatment and disposal of solid and hazardous waste from our facilities; and
- the Toxic Substances Control Act, also known as TSCA, and analogous state laws that impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities.

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities for pollution resulting from our operations or existing at our owned or operated facilities. Numerous governmental authorities, such as the U.S. Environmental Protection Agency, or the EPA, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations.

There is an inherent risk of incurring significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbon wastes and potential emissions and discharges related to our operations. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of substances or wastes on, under or from our properties and facilities, many of which have been used for midstream activities for many years, often by third parties not under our control. Private parties, including the owners of the properties through which our gathering or transportation systems pass and facilities where our wastes are taken for reclamation or disposal, may also 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. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. Finally, future federal and/or state restrictions, caps, or taxes on greenhouse gas emissions that may be passed in response to climate-change concerns may impose additional capital investment requirements, increase our operating costs and reduce the demand for our services.

Our construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

One of the ways we intend to grow our business is through the construction of new midstream assets. The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties that are beyond our control. Such expansion projects may also require the expenditure of significant amounts of capital, and financing may not be available on economically acceptable terms or at all. If we undertake these projects, they may not be completed on schedule, at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a pipeline, the construction may occur over an extended period of time, yet we will not receive any material increases in revenues until the project is completed. Moreover, we could construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we often do not have access to third-party estimates of potential reserves in an area prior to constructing facilities in that area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate as a result of the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing assets may require us to obtain new rights-of-way. We may be unable to obtain such rights-of-way and may, therefore, be unable to connect new natural gas volumes to our systems or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing existing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

If Anadarko were to limit divestitures of midstream assets to us or if we were to be unable to make acquisitions on economically acceptable terms from Anadarko or third parties, our future growth would be limited, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per-unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per-unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants, including, most notably, Anadarko. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our ability to grow our operations and increase our distributions to our unitholders.

If we are unable to make accretive acquisitions from Anadarko or third parties, either because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (ii) unable to obtain financing for these acquisitions on economically acceptable terms or (iii) outbid by competitors, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per-unit basis.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenues and costs, including synergies;
- an inability to successfully integrate the assets or businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management s and employees attention from other business concerns;
- unforeseen difficulties operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We have a partial ownership interest in Fort Union, which limits our ability to operate and control this entity. In addition, we may be unable to control the amount of operating cash flow we will receive from this entity and we may be required to contribute a significant amount of cash to fund our share of its operations, which could adversely affect our ability to make cash distributions to our unitholders.

We own a 14.81% non-managing membership interest in Fort Union. Thus, our inability or limited ability to control the operations and management of Fort Union could cause us not to receive the amount of cash we expect to be distributed to us. Specifically, the following items may reduce cash available for distribution to us from Fort Union:

- we are unable to control the ongoing operational decisions of Fort Union, including the incurrence of capital expenditures;

we have limited ability to control decisions with respect to the operations of Fort Union, including decisions with respect to distributions to us;

Fort Union may establish reserves for working capital, capital projects, environmental matters and legal proceedings, which reserves would reduce the amount of cash available for distribution by Fort Union; and

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- Fort Union may incur additional indebtedness, whereby required principal and interest payments may reduce the amount of cash available for distribution by Fort Union.

Any of the above could significantly and adversely impact our ability to make cash distributions to our unitholders.

We do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to 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 more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines 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, financial condition and ability to make cash distributions to our unitholders.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not fully insured, our operations and financial results could be adversely affected.

Our operations are subject to all of the risks and hazards inherent in the gathering, compressing, processing, treating and transportation of natural gas, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, farm and utility equipment;
- leaks of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;
- leaks of natural gas containing hazardous quantities of hydrogen sulfide from our Pinnacle gathering system or Bethel treating facility;
- fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. For example, we do not have any property insurance on our underground pipeline systems that would cover damage to the pipelines. In addition, although we are insured for environmental pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might incur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to certain indemnification rights, for potential environmental liabilities.

We are exposed to the credit risk of Anadarko and third-party customers, and any material non-payment or non-performance by these parties, including with respect to our gathering, processing and transportation agreements, our $260.0 million note receivable from Anadarko and our commodity price swap agreements with Anadarko, could reduce our ability to make distributions to our unitholders.

We are dependent on Anadarko for the majority of our revenues. Consequently, we are subject to the risk of non-payment or non-performance by Anadarko, including with respect to our gathering and transportation agreements, our $260.0 million note receivable and our commodity price swap agreements. Any such non-payment or non-performance could reduce our ability to make distributions to our unitholders. Furthermore, Anadarko is subject to its own financial, operating and regulatory risks, which could increase the risk of default on its obligations to us. We cannot predict the extent to which

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Anadarko s business would be impacted if conditions in the energy industry were to continue to deteriorate, nor can we estimate the impact such conditions would have on Anadarko s ability to perform under our gathering and transportation agreements, note receivable or our commodity price swap agreements. Further, unless and until we receive full repayment of the $260.0 million note receivable from Anadarko, we will be subject to the risk of non-payment or late payment of the interest payments and principal of the note. Accordingly, any material non-payment or non-performance by Anadarko could reduce our ability to make distributions to our unitholders.

With respect to our Hilight and Newcastle systems, we rely on a significant number of third-party customers for substantially all of our revenues related to those assets. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness, inability to negotiate extensions, or replacements of contracts or otherwise, could reduce our ability to make cash distributions to our unitholders.

Anadarko s credit facility and other debt instruments contain financial and operating restrictions that may limit our access to credit. In addition, our ability to obtain credit in the future may be affected by Anadarko s credit rating.

We have the ability to incur up to $100.0 million of indebtedness under Anadarko s $1.3 billion credit facility. However, this $100.0 million of borrowing capacity will be available to us only to the extent that sufficient amounts remain unborrowed by Anadarko. As a result, borrowings by Anadarko could restrict our access to credit. In addition, if we or Anadarko were to fail to comply with the terms of this credit facility, we could be unable to make any borrowings under Anadarko s credit facility, even if capacity were otherwise available. As a result, the restrictions in Anadarko s credit facility could adversely affect our ability to finance our future operations or capital needs or to engage in, expand or pursue our business activities, and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Anadarko s and our ability to comply with the terms of its and our respective debt instruments may be affected by events beyond its and our control, including prevailing economic, financial and industry conditions. We and Anadarko are subject to covenants, and Anadarko is subject to a debt-to-capitalization ratio, under Anadarko s credit facility. Should we or Anadarko fail to comply with any covenants under Anadarko s credit facility, we could be unable to make any borrowings under that credit facility. Additionally, a default by Anadarko under one of its debt instruments may cause a cross-default under Anadarko s other debt instruments, including the credit facility under which we are a co-borrower. Accordingly, a breach by Anadarko of certain of the covenants or ratios in another debt instrument could cause the acceleration of any indebtedness we have outstanding under the credit facility. In the event of an acceleration, we might not have, or be able to obtain, sufficient funds to make the required repayments of debt, finance our operations and pay distributions to unitholders. For more information regarding our debt agreements, please read *Item 7 Management s discussion and analysis of financial condition and results of operations Liquidity and capital resources*.

Due to our relationship with Anadarko, our ability to obtain credit will be affected by Anadarko s credit rating. Even if we obtain our own credit rating or separate financing arrangement, any future change in Anadarko s credit rating would likely also result in a change in our credit rating. Regardless of whether we have our own credit rating, a downgrading of Anadarko s credit rating could limit our ability to obtain financing in the future upon favorable terms or at all.

Debt we owe or incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Future levels of indebtedness, including that we owe through our $175.0 million term loan with Anadarko, could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;

- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and

- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

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Increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Interest rates may increase in the future, whether because of inflation, increased yields on U.S. Treasury obligations or otherwise. In such cases, the interest rate on our five-year $175.0 million term loan with Anadarko, which after December 2010 will be calculated at a floating rate equal to three-month LIBOR plus 150 basis points, would increase. If interest rates rise, our future financing costs could increase accordingly. In addition, as is true with other MLPs (the common units of which are often viewed by investors as yield-oriented securities), our unit price is impacted by our level of cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

RISKS INHERENT IN AN INVESTMENT IN US

Anadarko owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Anadarko and our general partner have conflicts of interest with, and may favor Anadarko s interests to the detriment of our unitholders.

Anadarko owns and controls our general partner and has the power to appoint all of the officers and directors of our general partner, some of whom are also officers of Anadarko. Although our general partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owner, Anadarko. Conflicts of interest may arise between Anadarko and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of Anadarko over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our partnership agreement nor any other agreement requires Anadarko to pursue a business strategy that favors us.

- Anadarko is not limited in its ability to compete with us and may offer business opportunities or sell midstream assets to parties other than us.

- Our general partner is allowed to take into account the interests of parties other than us, such as Anadarko, in resolving conflicts of interest.

- The officers of our general partner will also devote significant time to the business of Anadarko and will be compensated by Anadarko accordingly.

- Our partnership agreement limits the liability of and reduces the fiduciary duties owed by our general partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.

- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.

- Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner and the ability of the subordinated units to convert to common units.

Our general partner determines which costs incurred by it are reimbursable by us.

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.

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Our partnership agreement permits us to classify up to $31.8 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or to our general partner in respect of the general partner interest or the incentive distribution rights.

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 right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.

Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.

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

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner s incentive distribution rights without the approval of the special committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

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

Anadarko is not limited in its ability to compete with us and is not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

Anadarko is not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, Anadarko may acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities. Moreover, while Anadarko may offer us the opportunity to buy additional assets from it, it is under no contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed.

Cost reimbursements due to Anadarko and our general partner for services provided to us or on our behalf will be substantial and will reduce our cash available for distribution to our unitholders. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making distributions on our common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by Anadarko and our general partner in managing and operating us. While our reimbursement of allocated general and administrative expenses is capped until December 31, 2009 under the omnibus agreement, we are required to reimburse Anadarko and our general partner for all direct operating expenses incurred on our behalf. These direct operating expense reimbursements and the reimbursement of incremental general and administrative expenses we will incur as a result of being a publicly traded partnership are not capped. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursements to Anadarko and our general partner will reduce the amount of cash otherwise available for distribution to our unitholders.

If you are not an Eligible Holder, you may not receive distributions or allocations of income or loss on your common units and your common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common and subordinated units. Eligible Holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity s owners are U.S. individuals or entities subject to such taxation. If you are not an Eligible Holder, our general partner may elect not to make distributions or allocate income or loss on your units and you run the risk of having your units redeemed by us at the lower of your purchase price cost and the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Our general partner s liability regarding our obligations is limited.

Our general partner included provisions in its and our contractual arrangements that limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. Furthermore, we used substantially all of the net proceeds from our initial public offering to make a loan to Anadarko, and therefore, the net proceeds from our initial public offering was not used to grow our business.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per-unit distribution level. There are no limitations in our partnership agreement or in Anadarko s credit facility, under which we are a co-borrower, on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Our partnership agreement limits our general partner s fiduciary duties to holders of our common and subordinated units.

Our partnership agreement contains provisions that modify and reduce the fiduciary 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, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its affiliates;
- whether to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels; and
- whether or not to consent to any merger or consolidation of the Partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common and subordinated units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;

- 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 such decisions are made in good faith, meaning that it believed that the decision was in the best interest of our partnership;

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- provides that our general partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:
  (a) approved by the special committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

  (b) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

  (c) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

  (d) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the special committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (c) and (d) 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.

Our general partner may elect to cause us to issue Class B and general partner units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the special committee of its board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of Class B units and general partner units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued to our general partner will be equal to that number of common units which would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. Our general partner will be issued the number of general partner units necessary to maintain our general partner s interest in us that existed immediately prior to the reset election. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued Class B units, which are entitled to distributions on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new Class B units and general partner units to our general partner in connection with resetting the target distribution levels.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

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 on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner will be chosen by Anadarko. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our 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.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

The unitholders initially will be unable to remove our general partner without its consent because our general partner and its affiliates currently own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 % of all outstanding limited partner units voting together as a single class is required to remove our general partner. As of February 27, 2009, Anadarko owns 62.6% of our outstanding common and subordinated units. 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 convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined 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 charges of poor management of the business, so the removal of our general partner because of the unitholder s dissatisfaction with our general partner s performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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

Unitholders voting rights are further restricted by a provision of our partnership agreement 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, 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.

Our general partner interest or 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 Anadarko to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.

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

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

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

Anadarko may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of February 27, 2009, Anadarko holds an aggregate of 8,282,322 common units and 26,536,306 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. The sale of any or all of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market on which common units are traded.

Our general partner has a limited call right that may require existing unitholders to sell their 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, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price. As a result, existing unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Existing unitholders may also incur a tax liability upon a sale of their units. As of February 27, 2009, Anadarko owns approximately 28.5% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), Anadarko will own approximately 62.6% of our outstanding common units.

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

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

- we were conducting business in a state but had not complied with that particular state s partnership statute; or
- that unitholder s right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute control of our business.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were

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unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

We incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership prior to our initial public offering. As a publicly traded partnership, we incur significant legal, accounting and other expenses. In addition, the Sarbanes-Oxley Act of 2002 and related rules subsequently implemented by the SEC and the New York Stock Exchange, or the NYSE, have required changes in the corporate governance practices of publicly traded companies. We expect these rules and regulations to increase our legal and financial compliance costs compared to our historical costs and to make activities more time-consuming and costly.

If we are deemed to be an investment company under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our assets include, among other items, a $260.0 million note receivable from Anadarko. If this note receivable together with a sufficient amount of our other assets are deemed to be investment securities, within the meaning of the Investment Company Act of 1940, or the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or contract rights so as to fall outside of the definition of investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property from or to our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events would adversely affect the price of our common units and could have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes, in which case we would be treated as a corporation for federal income tax purposes. As a result, we would pay federal income tax on our taxable income at the corporate tax rate, distributions to our unitholders would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to our unitholders. If we were taxed as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as an investment company would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

We expect to amend our partnership agreement to provide that any net termination losses treated as arising during the subordination period as a result of an adjustment to the carrying value of our assets in connection with an issuance by us of additional units will be allocated among the holders of subordinated units and common units in proportion to their percentage interests. As a result of this amendment, if we liquidate during the subordination period, it is possible there would be less net termination gain to be allocated to unitholders holding common units, resulting in those unitholders receiving less liquidation proceeds than under our current partnership agreement. In order to mitigate the possibility of adverse consequences to our common units of this revised allocation, we also intend to amend our partnership agreement to provide that, in the event we liquidate during the subordination period, we will allocate items of income, gain, loss and deduction that would otherwise be included in the computation of net termination gain or net termination loss and, if necessary, items included in our net income or net losses, in each case to the extent possible, so that the capital account of each common unit will equal the amount it would have been had we not amended our partnership agreement. In the unlikely event that we liquidate during the subordination period and we do not have sufficient items included in net termination gain, net termination loss, or other items of income, gain, loss and deduction, as the case may be, to cause the capital account in respect of each common unit to equal this amount, unitholders holding common units could receive less liquidation proceeds than under our current partnership agreement.

Our partnership agreement currently provides that any net termination loss, as defined in the partnership agreement, deemed recognized during the subordination period as the result of an adjustment to the carrying value of our assets in connection with an issuance of additional units will first be allocated to the general partner and unitholders holding subordinated units until the capital account with respect to each subordinated unit has been reduced to zero. Under our current partnership agreement, an issuance of additional units at a time when our common units are trading at a price lower than the capital account balance of our then outstanding common units may require us to adjust the carrying value of our property to an amount that causes the capital account with respect to each of our (i) subordinated units to equal zero and (ii) existing common units to equal the then-current trading price of common units.

While the existing allocation provisions are intended to preserve the senior economic position of our common units during the subordination period, they may also have the effect of causing the holders of our common units to suffer adverse tax consequences. A book down of our assets that results in the capital account in respect of each subordinated unit equaling zero would require a substantial reduction in the carrying value of our property. As a result of such a book down and because we have adopted the remedial allocation method with respect to the depreciation and amortization of our assets, the amount of tax depreciation and amortization allocated to holders of our common units could be substantially reduced. There would be a corresponding reduction in the amount of taxable income allocated to the holders of subordinated units.

In order to mitigate the possibility of this adverse tax effect to the common units and corresponding benefit to the subordinated units, we expect to amend our partnership agreement to provide that any net termination loss, as defined in the partnership agreement, deemed to be recognized by us during the subordination period as a result of a book down in the carrying value of our assets will be allocated pro rata to the holders of common units *and* subordinated units. This amendment will not affect the amount of the reduction in the capital account with respect to a common unit resulting from a book down. Under both the current partnership agreement and the amended partnership agreement, the capital account with respect to each existing common unit will be decreased to the trading price of common units existing at the time of the contribution to us that requires us to book down the carrying value of our assets. The amendment will reduce (perhaps substantially) the amount of the book down in the carrying value of our assets, as well as the amount of the resulting reduction in tax depreciation allocable to holders of common units that would otherwise occur pursuant to the book down provisions contained in the current partnership agreement.

While the amount of the decrease in the capital account of an existing holder of common units will not be affected by the amendment to our partnership agreement, the potential amount of net termination gain recognized by us if we liquidate during the subordination period may be substantially reduced as a result of the amendment. Therefore, our amended partnership agreement will provide that upon a liquidation during the subordination period, we will specially allocate items included in net termination gain or net termination loss and, if necessary, items of income, gain, loss and deduction that would otherwise be included in our net income or net losses, in each case to the maximum extent possible, to cause the capital account of each common unit to equal the amount the capital account would have been had we not amended our partnership agreement. In the unlikely event that we liquidate during the subordination period and we do not have sufficient items included in net termination gain, net termination loss, or other items of income, gain, loss and deduction, as the case may be, to cause the capital account in respect of each common unit to equal this amount, unitholders holding common units could receive less liquidation proceeds than under our current partnership agreement.

TAX RISKS TO COMMON UNITHOLDERS

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders could be substantially reduced.

The anticipated after-tax economic benefit of an investment in our 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 Internal Revenue Service, or the IRS, on this or any other tax matter affecting us.

Despite the fact that we are classified as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced.

Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to a material amount of entity-level taxation at the state or federal level. In addition, if we are deemed to be an investment company, as described above, we would be subject to such taxation.

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At the state level, were we to be subject to federal income tax, we would also be subject to the income tax provisions of many states. Moreover, because of widespread state budget deficits and other reasons, several states are evaluating ways to independently subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas margin tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas. Imposition of such a tax on us by Texas and, if applicable, by any other state will reduce the cash available for distribution to our unitholders.

Our 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, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws or interpretations thereof could make it more difficult or impossible to meet the requirements for us to be treated as a partnership for U.S. federal income tax purposes, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. Modifications to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict any particular change. Any potential change in law or interpretation thereof could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

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

If the IRS contests the federal income tax positions we take or the pricing of our related party agreements with Anadarko, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us, including the pricing of our related party agreements with Anadarko. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of or the positions we take. A court may not agree with some or all of the positions we take. For example, the IRS may reallocate items of income, deductions, credits or allowances between related parties if the IRS determines that such reallocation is necessary to prevent evasion of taxes or clearly to reflect the income of any such related parties. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. If the IRS were successful in any such challenge, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders and our general partner. Such a reallocation may require us and our unitholders to file amended tax returns. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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

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

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Our 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 that income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If a unitholder disposes of common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and that unitholder s tax basis in those common units. Because distributions in excess of a unitholder s allocable share of our net taxable income decrease that unitholder s tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to her, if she sells such units at a price greater than her tax basis in those units, even if the price received is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if a unitholder sells her units, she may incur a tax liability in excess of the amount of cash received from the sale.

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs 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 U.S. federal tax returns and pay tax on their share of our taxable income. Any tax-exempt entity or a non-U.S. person should consult its tax advisor before investing in our common units.

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

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

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

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

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

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

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-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. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in the unitholder s taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties, if we are unable to determine that a termination occurred.

Our unitholders are subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our common units.

In addition to federal income taxes, our unitholders are subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in the states of Kansas, Oklahoma, Texas, Utah and Wyoming. Each of these states, other than Texas and Wyoming, currently imposes a personal income tax, and all of these states impose income taxes on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is the responsibility of each unitholder to file all required U.S. federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

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

None

Item 3. ***Legal Proceedings***

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Please see *Items 1 and 2 Business and Properties*, in this Form 10-K for more information.

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

None

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PART II

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

MARKET INFORMATION

Our common units are listed on the New York Stock Exchange under the symbol WES. Common units began trading on May 9, 2008, at an initial offering price of $16.50 per unit. Prior to May 9, 2008, our equity securities were not listed on any exchange or traded in any public market. The following table sets forth the high and low closing prices of the common units as well as the amount of cash distributions declared and paid for each quarter since our initial public offering.

	Quarter Ended December 31, 2008	Quarter Ended September 30, 2008	Quarter Ended June 30, 2008
High Price	$ 15.17	$ 16.96	$ 17.25
Low Price	$ 10.58	$ 13.02	$ 16.15
Distribution per common unit	$ 0.30	$ 0.1582	
Distribution per subordinated unit	$ 0.30	$ 0.1582	

As of February 27, 2009, there were approximately 12 unitholders of record of the Partnership s common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record.

We have also issued 26,536,306 subordinated units and 1,135,296 general partner units, for which there is no established public trading market. All of the subordinated units and general partner units are held by affiliates of our general partner. Our general partner and its affiliates receive quarterly distributions on these units only after sufficient funds have been paid to the common units.

USE OF PROCEEDS FROM SALE OF SECURITIES

We completed our initial public offering of 20,810,875 common units, including 2,060,875 common units sold pursuant to the partial exercise by the underwriters of their option to purchase additional common units, representing limited partnership interests in us at a price of $16.50 per unit. In connection with the offering, we issued to our general partner 1,083,115 general partner units and 100% of our IDRs, which entitle our general partner to increasing percentages up to a maximum of 50.0% of cash distributions based on the amount of the quarterly cash distribution. We also issued 5,725,431 common units and 26,536,306 subordinated units to a subsidiary of Anadarko. Subsidiaries of Anadarko contributed our initial assets to us in connection with the offering.

Net proceeds of $321.1 million (net of $22.3 million of underwriting discount and structuring fees) from our initial public offering were used (i) to pay approximately $5.9 million in expenses associated with the offering and the transactions related thereto, (ii) to make a loan of $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.5%, (iii) to reimburse Anadarko $45.2 million from offering proceeds and (iv) retained $10.0 million for general partnership purposes.

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SELECTED INFORMATION FROM OUR PARTNERSHIP AGREEMENT

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions, minimum quarterly distributions and IDRs.

Available cash

The partnership agreement requires that, within 45 days subsequent to the end of each quarter, beginning with the quarter ended June 30, 2008, the Partnership distribute all of its available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. The amount of available cash generally is 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 to fund future capital expenditures, to comply with applicable laws, or our debt instruments and other agreements, or to provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters. Working capital borrowings generally include borrowings made under a credit facility or similar financing arrangement.

Minimum quarterly distributions

The partnership agreement provides that, during a period of time referred to as the subordination period, the common units are entitled to distributions of available cash each quarter in an amount equal to the minimum quarterly distribution, which is $0.30 per common unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash are permitted on the subordinated units. Furthermore, arrearages do not apply to and therefore will not be paid on the subordinated units. The effect of the subordinated units is to increase the likelihood that, during the subordination period, available cash is sufficient to fully fund cash distributions on the common units in an amount equal to the minimum quarterly distribution.

The subordination period will lapse at such time when the Partnership has paid at least $0.30 per quarter on each common unit, subordinated unit and general partner unit for any three consecutive, non-overlapping four-quarter periods ending on or after June 30, 2011. Also, if the Partnership has paid at least $0.45 per quarter (150% of the minimum quarterly distribution) on each outstanding common unit, subordinated unit and general partner unit for each calendar quarter in a four-quarter period, the subordination period will terminate automatically. The subordination period will also terminate automatically if the general partner is removed without cause and the units held by the general partner and its affiliates are not voted in favor of such removal. When the subordination period lapses or otherwise terminates, all remaining subordinated units will convert into common units on a one-for-one basis and the common units will no longer be entitled to preferred distributions on prior-quarter distribution arrearages. All subordinated units are held indirectly by Anadarko.

General partner interest and incentive distribution rights

The general partner is currently entitled to 2.0% of all quarterly distributions that the Partnership makes prior to its liquidation. After distributing amounts equal to the minimum quarterly distribution to common and subordinated unitholders and distributing amounts to eliminate any arrearages to common unitholders, our general partner is entitled to incentive distributions pursuant to its ownership of our IDRs if the amount we distribute with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions: Unitholders	General Partner
Minimum Quarterly Distribution	$0.300	98%	2%
First Target Distribution	up to $0.345	98%	2%
Second Target Distribution	above $0.345 up to $0.375	85%	15%
Third Target distribution	above $0.375 up to $0.450	75%	25%
Thereafter	above $0.45	50%	50%

The table above assumes that our general partner maintains its 2% general partner interest, that there are no arrearages on common units and our general partner continues to own the IDRs. The maximum distribution sharing percentage of

50.0% includes distributions paid to the general partner on its 2.0% general partner interest and does not include any distributions that the general partner may receive on limited partner units that it may own or acquire.

OTHER SECURITY MATTERS

Sales of Unregistered Units

On December 19, 2008, we acquired certain midstream assets from Anadarko for consideration consisting of $175.0 million cash, 2,556,891 of our common units and 52,181 of our general partner units. The common units and general partner units issued in connection with the acquisition were issued to subsidiaries of Anadarko Petroleum Corporation in a private placement and the issuance was not registered with the SEC.

Securities Authorized for Issuance Under Equity Compensation Plans

In connection with the closing of our initial public offering, our general partner adopted the Western Gas Partners, LP 2008 Long-Term Incentive Plan, or LTIP, which permits the issuance of up to 2,250,000 units. Phantom unit grants have been made to each of the independent directors of our general partner under the LTIP. Please read the information under *Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters* of this report, which is incorporated by reference into this Item 5.

Repurchase of Equity

None

Item 6. *Selected Financial and Operating Data*

The following table shows our selected financial and operating data for the periods and as of the dates indicated, which is derived from our consolidated financial statements. On May 14, 2008, we closed our initial public offering of 18,750,000 common units. Concurrent with the closing of the offering, Anadarko contributed to us the assets and liabilities of the Predecessor, which were comprised of AGC, PGT and MIGC, which we refer to as our initial assets. On June 11, 2008, we issued an additional 2,060,875 common units to the public and 751,625 common units to Anadarko in connection with the partial exercise of the underwriters over-allotment option. On December 19, 2008, we closed the Powder River acquisition with Anadarko. Anadarko acquired MIGC and the Powder River assets in connection with its August 23, 2006 acquisition of Western.

Our acquisition of the initial assets and the Powder River acquisition are considered transfers of net assets between entities under common control. Accordingly, our consolidated financial statements include the combined financial results and operations of AGC and PGT from their inception through the closing date of our initial public offering and to the Partnership s consolidated financial statements thereafter, combined with the financial results and operations of MIGC and the Powder River acquisition from August 23, 2006 thereafter.

The information in the following table should be read together with *Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations* in this Form 10-K.

	Summary Financial Information				
	2008	2007(1)	2006(1)	2005	2004
	(in thousands, except per unit data)				
Statement of Income Data:					
Total revenues	**$ 311,648**	$261,493	$128,610	$ 71,650	$ 68,049
Costs and expenses	**199,566**	166,994	80,752	35,720	31,301
Depreciation and impairment	**42,365**	30,481	20,230	15,447	14,841
Total operating expenses	**241,931**	197,475	100,982	51,167	46,142
Operating income	**69,717**	64,018	27,628	20,483	21,907
Interest income (expense), net	**9,191**	(7,805)	(9,574)	(8,650)	(7,146)
Other income (expense), net	**145**	(15)	(26)	66	
Income tax expense (2)	**13,777**	19,540	5,327	4,789	5,504
Net income	**$ 65,276**	$ 36,658	$ 12,701	$ 7,110	$ 9,257
Gross margin (3)	**$ 159,716**	$140,666	$ 83,235	$ 64,841	$ 63,065
General partner interest in net income (4)	**$ 842**	n/a	n/a	n/a	n/a
Common unitholders interest in net income (4)	**$ 20,841**	n/a	n/a	n/a	n/a
Subordinated unitholders interest in net income (4)	**$ 20,420**	n/a	n/a	n/a	n/a
Net income per common unit (basic and diluted)	**$ 0.78**	n/a	n/a	n/a	n/a
Net income per subordinated unit (basic and diluted)	**$ 0.77**	n/a	n/a	n/a	n/a
Distributions per unit	**$ 0.46**	n/a	n/a	n/a	n/a
Balance Sheet Data (at period end):					
Property, plant and equipment, net	**$ 517,815**	$511,775	$464,919	$200,451	$196,065
Total assets	**856,441**	544,318	504,383	206,373	199,110
Total long-term liabilities	**185,146**	139,801	140,071	37,664	30,573
Total partners capital and parent net equity	**$ 654,954**	$392,140	$352,578	$160,585	$162,542
Cash Flow Data:					
Net cash provided by (used in):					
Operating activities	**$ 109,796**	$ 72,908	$ 33,304	$ 30,131	$ 31,160
Investing activities	**(479,959)**	(54,328)	(42,963)	(21,076)	(16,548)
Financing activities	**403,469**	(19,038)	10,113	(9,067)	(14,596)

Adjusted EBITDA[5]	**112,474**	91,830	47,239	35,930	36,748
Capital expenditures, net	**$ 36,864**	$ 54,328	$ 42,963	$ 20,841	$ 16,548
Operating Data:					
Affiliate					
Gathering throughput (MMcf/d)	**831**	917	891	757	715
Third Party					
Gathering throughput (MMcf/d)	**135**	90	80	41	31
Processing throughput (MMcf/d)	**30**	30	30		
Total					
Gathering throughput (MMcf/d)	**966**	1,007	971	798	746
Processing throughput (MMcf/d)	**30**	30	30		
Average gross margin per Mcf	**$ 0.44**	$ 0.37	$ 0.23	$ 0.22	$ 0.23

(1) Financial information for 2007 and 2006 has been revised to include results attributable to the Powder River assets from August 23, 2006. See *Note 3 Powder River Acquisition* of the notes to the consolidated financial statements in *Item 8 Financial Statements and Supplementary Data*.

(2) Includes federal and state income tax expense for all of our assets through May 13, 2008. For the period beginning May 14, 2008 and ending December 19, 2008 includes Texas margin

tax expense for our initial assets and federal and state income tax expense for the Powder River assets and for the period beginning December 20, 2008 and ending December 31, 2008, includes Texas margin tax expense for all of our assets. See *Note 6 Transactions with Affiliates* of the notes to the consolidated financial statements in *Item 8 Financial Statements and Supplementary Data*.

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(3) We define gross margin as gathering, processing and transportation revenues, plus natural gas, natural gas liquids and condensate sales, less cost of product.

(4) Net income is allocated among the general partner, common unitholders and subordinated unitholders and is attributable to the initial assets for periods including and subsequent to May 14, 2008 and the Powder River assets for periods including and subsequent to December 19, 2008. Prior to May 14, 2008 in the case of the initial assets and December 19, 2008 in the case of the Powder River acquisition, all income is attributed to the Predecessor. See *Note 5 Net Income per Limited Partner Unit* of the notes

to the consolidated financial statements in *Item 8 Financial Statements and Supplementary Data*.

(5) Adjusted EBITDA is not defined in GAAP. Adjusted EBITDA is presented because it is helpful to management, industry analysts, investors, lenders and rating agencies in assessing the financial performance and operating results of our fundamental business activities. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please see *Non-GAAP Financial Measures* in this Item.

NON-GAAP FINANCIAL MEASURES

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss), plus distributions from equity investee, interest expense, income tax expense and depreciation, less income from equity investments, interest income, income tax benefit and other income (expense). We believe that the presentation of Adjusted EBITDA provides information useful to investors in assessing our financial condition and results of operations and that Adjusted EBITDA is a widely accepted financial indicator of a company s ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA is a supplemental financial measure that management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;

- the ability of our assets to generate cash flow to make distributions; and

- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

Reconciliation to GAAP measures

The GAAP measures most directly comparable to Adjusted EBITDA are net income and net cash provided by operating activities. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to the GAAP measures of net income or net cash provided by operating activities. Adjusted EBITDA has important limitations as an analytical tool because it excludes some but not all items that affect net income and net cash provided by operating activities. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between Adjusted EBITDA compared to net income and net cash provided by operating activities, and incorporating this knowledge into its decision-making processes. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results.

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The following tables present a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measures of net income and net cash provided by operating activities:

	Summary Financial Information				
	2008	2007[(1)]	2006[(1)]	2005	2004
			(in thousands)		
Reconciliation of Adjusted EBITDA to net income					
Adjusted EBITDA	**$112,474**	$91,830	$47,239	$35,930	$36,748
Less:					
Distributions from equity investee	**5,128**	1,348	741		
Interest expense, net affiliates	**1,259**	7,805	9,574	8,650	7,146
Interest expense from note affiliate	**253**				
Income tax expense	**13,777**	19,540	5,327	4,789	5,504
Depreciation and impairment	**42,365**	30,481	20,230	15,447	14,841
Other expense, net		15	26		
Add:					
Equity income, net	**4,736**	4,017	1,360		
Interest income from note affiliate	**10,703**				
Other income	**145**			66	
Net income	**$ 65,276**	$36,658	$12,701	$ 7,110	$ 9,257
Reconciliation of Adjusted EBITDA to Net Cash Provided by Operating Activities					
Adjusted EBITDA	**$112,474**	$91,830	$47,239	$35,930	$36,748
Interest income (expense), net affiliates	**9,191**	(7,805)	(9,574)	(8,650)	(7,146)
Current income tax expense	**(12,153)**	(8,724)	(2,101)		
Other income (expense), net	**145**	(15)	(26)	66	
Distributions from equity investee in excess of equity income, net	**(392)**	2,669	619		
Changes in operating working capital:					
Accounts receivable and natural gas imbalances	**(4,959)**	(3,692)	2,037	(662)	933
Accounts payable and accrued expenses	**4,840**	142	(4,312)	3,373	(551)
Other, including changes in non-current assets and liabilities	**650**	(1,497)	(578)	74	1,176
Net cash provided by operating activities	**$109,796**	$72,908	$33,304	$30,131	$31,160

(1) Financial information for 2007 and 2006 has been revised to include results attributable to the Powder River assets from August 23, 2006. See *Note 3 Powder River Acquisition* of the notes to the consolidated financial statements in *Item 8 Financial Statements and Supplementary Data*.

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

OVERVIEW

We are a growth-oriented Delaware limited partnership organized by Anadarko to own, operate, acquire and develop midstream energy assets. We currently operate in East and West Texas, the Rocky Mountains (Utah and Wyoming) and the Mid-Continent (Kansas and Oklahoma) and are engaged in the business of gathering, compressing, treating, processing and transporting natural gas for Anadarko and third-party producers and customers.

OPERATING AND FINANCIAL HIGHLIGHTS

We achieved significant milestones during 2008. Significant operational and financial highlights include:

- closed our initial public offering in May 2008;
- completed our first acquisition of midstream assets from Anadarko in December 2008 in a challenging market environment;
- completed several system expansions, including modifying horsepower on our Dew gathering system; expanding our Bethel treating facility; connecting new wells, including 26 wells on our Hugoton gathering system and 13 wells on our Haley gathering system, and completed train two of the Fort Union gathering system; and
- leveraged our fee-based structure and managed capital and operating costs to generate cash flows, funding distributions to unitholders.

INITIAL PUBLIC OFFERING

On May 14, 2008, we closed our initial public offering of 18,750,000 common units at a price of $16.50 per unit. On June 11, 2008, we issued an additional 2,060,875 common units to the public pursuant to the partial exercise of the underwriters over-allotment option granted in connection with our initial public offering. Concurrent with the initial closing of the offering, Anadarko contributed the assets and liabilities of AGC, PGT and MIGC to us in exchange for 1,083,115 general partner units, representing a 2.0% general partner interest in the Partnership, 100% of the IDRs, and 5,725,431 common units and 26,536,306 subordinated units. The common units held by Anadarko include 751,625 common units issued to Anadarko following the expiration of the underwriters over-allotment option and represent the portion of the common units for which the underwriters did not exercise their over-allotment option. We refer to AGC, PGT and MIGC as our initial assets.

POWDER RIVER ACQUISITION

On December 19, 2008, we acquired certain midstream assets from Anadarko for consideration consisting of $175.0 million cash, which was financed by borrowing $175.0 million from Anadarko pursuant to the terms of a five-year term loan agreement, 2,556,891 of our common units and 52,181 of our general partner units. The acquired assets consisted of (i) a 100% ownership interest in the Hilight System, (ii) a 50% interest in the Newcastle System and (iii) a 14.81% limited liability company membership interest in Fort Union Gas Gathering, L.L.C. We refer to these assets collectively as the Powder River assets. The Powder River assets provide a combination of gathering, treating and processing services in the Powder River Basin of Wyoming.

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The following tables present the impact to the consolidated statements of income attributable to the Powder River assets (in thousands):

	Partnership Historical	Powder River Acquisition	Eliminations	Combined
	Year Ended December 31, 2008			
Revenues	$ 151,841	$ 159,967	$ (160)	$ 311,648
Operating expenses	93,986	148,105	(160)	241,931
Operating income	57,855	11,862		69,717
Interest and other income (expense), net affiliates	7,817	1,519		9,336
Income before income taxes	65,672	13,381		79,053
Income tax expense	8,772	5,005		13,777
Net income	$ 56,900	$ 8,376		$ 65,276
	Year Ended December 31, 2007			
Revenues	$ 117,993	$ 143,660	$ (160)	$ 261,493
Operating expenses	72,748	124,887	(160)	197,475
Operating income	45,245	18,773		64,018
Interest and other income (expense), net affiliates	(8,521)	701		(7,820)
Income before income taxes	36,724	19,474		56,198
Income tax expense	12,724	6,816		19,540
Net income	$ 24,000	$ 12,658		$ 36,658
	Year Ended December 31, 2006			
Revenues	$ 81,562	$ 47,105	$ (57)	$ 128,610
Operating expenses	58,379	42,660	(57)	100,982
Operating income	23,183	4,445		27,628
Interest and other income (expense), net affiliates	(9,657)	57		(9,600)
Income before income taxes	13,526	4,502		18,028
Income tax expense	3,814	1,513		5,327
Net income	$ 9,712	$ 2,989		$ 12,701

The following discussion analyzes our financial condition and results of operations and should be read in conjunction with our historical consolidated financial statements, and the notes thereto, included in Item 8 Financial Statements and Supplementary Data and Item 1A Risk Factors of this report on Form 10-K. For ease of reference, we refer to the historical financial results of AGC and PGT prior to our initial public offering, combined with the historical financial results of MIGC and the Powder River assets from August 23, 2006 thereafter, as being our historical financial results. Unless the context otherwise requires, references to we, us, our, the Partnership or Western Gas Partners intended to refer to the business and operations of Western Gas Partners, LP and its consolidated subsidiaries since May 14, 2008, the business and operations of AGC and PGT since their inception and the business and operations of MIGC and the Powder River assets since August 23, 2006. For purposes of the following discussion, Anadarko refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership.

OUR OPERATIONS

Our results are driven primarily by the volumes of natural gas we gather, compress, process, treat or transport through our systems. For the year ended December 31, 2008, our revenues were derived approximately as follows:

- 50% from natural gas and natural gas liquids sales;
- 40% from gathering, processing, compression and transportation activities;
- 5% from condensate sales; and
- 5% from equity income from our interest in Fort Union, changes in our imbalance positions and other revenues.

For the year ended December 31, 2008, approximately 86% of our total revenues and 83% of our gathering, processing and transportation throughput volumes were attributable to transactions entered into with Anadarko.

In our gathering operations, we contract with producers and customers to gather natural gas from individual wells located near our gathering systems. We connect wells to gathering lines through which natural gas may be compressed and delivered to a processing plant, treating facility or downstream pipeline, and ultimately to end users. We also treat a significant portion of the natural gas that we gather so that it will satisfy required specifications for pipeline transportation.

Effective January 1, 2008, we received a significant dedication from our largest customer, Anadarko, in order to maintain or increase our existing throughput levels and to offset the natural production declines of the wells currently connected to our gathering systems. Specifically, Anadarko has dedicated to us all of the natural gas production it owns or controls from (i) wells that are currently connected to our gathering systems, and (ii) additional wells that are drilled within one mile of wells connected to our gathering systems, as the systems currently exist and as they are expanded to connect additional wells in the future. As a result, this dedication will continue to expand as additional wells are connected to our gathering systems. Volumes associated with this dedication averaged approximately 646,000 MMBtu/d for the year ended December 31, 2008 and 734,000 MMBtu/d for the year ended December 31, 2007, based on throughput from the wells ultimately subject to the dedication.

Based on operating income for the year ended December 31, 2008, approximately 74% of our services are provided pursuant to fee-based contracts under which we are paid a fixed fee based on the volume and thermal content of the natural gas we gather, compress, treat or transport. This type of contract provides us with a relatively stable revenue stream that is not subject to direct commodity-price risk, except to the extent that we retain and sell drip condensate that is recovered during the gathering of natural gas from the wellhead.

Based on operating income for the year ended December 31, 2008, approximately 22% of our services are provided pursuant to percent-of-proceeds contracts pursuant to which Anadarko is typically responsible for the marketing of the natural gas and NGLs and we are entitled to a specified percentage of the net proceeds from the sale of natural gas and NGLs. Revenue is recognized when the natural gas or NGLs are sold and the related product purchases are recorded as a percent of the product sale. We have entered into fixed-price swap agreements with Anadarko to manage the commodity price risk inherent in our percent-of-proceeds contracts. See *Note 6 Transactions with Affiliates* of the notes to the consolidated financial statements included in *Item 8 Financial Statements and Supplementary Data* in this Form 10-K.

We also have indirect exposure to commodity price risk in that persistent low commodity prices may cause our current or potential customers to delay drilling or shut in production, which would reduce the volumes of natural gas available for gathering, compressing, treating, processing and transporting by our systems. We also bear a limited degree of commodity price risk through our condensate recovery and sale operations and through settlement of natural gas imbalances. Please read *Item 7A Quantitative and Qualitative Disclosures about Market Risk* below.

We provide a significant portion of our transportation services on our MIGC system through firm contracts that obligate our customers to pay a monthly reservation or demand charge, which is a fixed charge applied to firm contract capacity and owed by a customer regardless of the actual pipeline capacity used by that customer. When a customer uses the capacity it has reserved under these contracts, we are entitled to collect an additional commodity usage charge based on the actual volume of natural gas transported. These usage charges are typically a small percentage of the total revenues received from our firm capacity contracts. We also provide transportation services through interruptible contracts, pursuant to which a fee is charged to our customers based upon actual volumes transported through the pipeline.

As a result of our initial public offering and the Powder River acquisition, the results of operations, financial condition and cash flows vary significantly for 2008 as compared to periods ending prior to our initial public offering. Please see *Items Affecting the Comparability of Our Financial Results*, set forth below in this Item.

HOW WE EVALUATE OUR OPERATIONS

Our management relies on certain financial and operational metrics to analyze our performance. These metrics are significant factors in assessing our operating results and profitability and include (1) throughput volumes, (2) operating expenses, (3) Adjusted EBITDA and (4) gross margin.

Throughput volumes

In order to maintain or increase throughput volumes on our gathering and processing systems, we must connect additional wells to our systems. Our success in maintaining or increasing throughput is impacted by successful drilling of new wells by producers which will be dedicated to our systems, our ability to secure volumes from new wells drilled on non-dedicated acreage and our ability to attract natural gas volumes currently gathered, processed or treated by our competitors.

To maintain and increase throughput volumes on our MIGC system, we must continue to contract capacity to shippers, including producers and marketers, for transportation of their natural gas. Although firm capacity on the MIGC system is fully subscribed, we nevertheless monitor producer and marketing activities in the area served by our transportation system to maintain a full subscription of MIGC s firm capacity and to identify new opportunities.

Operating expenses

We analyze operating expenses to evaluate our performance. Operating expenses include all amounts accrued for or paid to affiliates or third parties for the operation of our systems, including product purchases, utilities, field labor, measurement and analysis and other disbursements. The primary components of our operating expenses that we evaluate include operation and maintenance expenses, cost of product expenses and general and administrative expenses. Certain of our operating expenses are paid to affiliates; however, affiliate expenses do not bear a direct relationship to affiliate revenues and third-party expenses do not bear a direct relationship to third-party revenues. Accordingly, our affiliate expenses are not those expenses necessary for generating our affiliate revenues and our third-party expenses are not those expenses necessary for generating our third-party revenues.

Operation and maintenance expenses include, among other things, direct labor, insurance, repair and maintenance, contract services, utility costs and services provided to us or on our behalf. For periods commencing on and subsequent to May 14, 2008 with respect to our initial assets and for periods commencing on and subsequent to December 1, 2008 with respect to the Powder River assets, these expenses are incurred under and governed by our services and secondment agreement with Anadarko.

Cost of product expenses include (i) costs associated with the purchase of natural gas and NGLs pursuant to our percent-of-proceeds processing contracts, (ii) costs associated with the purchase of natural gas pursuant to the gas imbalance provisions contained in our contracts, (iii) costs associated with our obligations under certain contracts to redeliver a volume of natural gas to shippers which is thermally equivalent to condensate retained by us and sold to third parties and (iv) costs associated with our fuel tracking mechanism, which tracks the difference between actual fuel usage and loss and amounts recovered for estimated fuel usage and loss under our contracts. These expenses are subject to variability, although our exposure to commodity price risk attributable to our percent-of-proceeds contracts is mitigated through our commodity price swap agreements with Anadarko. For the years ended December 31, 2008, 2007 and 2006, cost of product expenses comprised 56%, 57% and 41% of total operating expenses, respectively.

General and administrative expenses for periods prior to May 14, 2008 with respect to our initial assets and for periods prior to December 1, 2008 with respect to the Powder River assets, include reimbursements attributable to costs incurred by Anadarko on our behalf and allocations of Anadarko s general and administrative costs by Anadarko to us. For these periods, Anadarko received compensation or reimbursement through a management services fee. Subsequent to May 14, 2008 with respect to our initial assets and subsequent to December 1, 2008 with respect to the Powder River assets, Anadarko is no longer compensated for corporate services through a management services fee. Instead, we reimburse Anadarko for general and administrative expenses it incurs on our behalf pursuant to the terms of our omnibus agreement with Anadarko. Amounts required to be reimbursed to Anadarko under the omnibus agreement include those expenses attributable to our status as a publicly traded partnership, such as:

- expenses associated with annual and quarterly reporting;
- tax return and Schedule K-1 preparation and distribution expenses;
- expenses associated with listing on the New York Stock Exchange; and
- independent auditor fees, legal fees, investor relations expenses, and registrar and transfer agent fees.

In addition to the above, we are required pursuant to the terms of the omnibus agreement with Anadarko, to reimburse Anadarko for allocable general and administrative expenses. The amount required to be reimbursed by us to Anadarko for allocated general and administrative expenses was originally capped at $6.0 million annually; however, this amount was increased to $6.65 million annually in connection with the Powder River acquisition. The annual expense cap stipulated in the omnibus agreement is effective through December 31, 2009, subject to adjustment to reflect changes in the Consumer Price Index and, with the concurrence of the special committee of our general partner s board of directors, to reflect expansions of our operations through the acquisition or construction of new assets or businesses. After December 31, 2009, our general partner will determine the general and administrative expenses to be reimbursed by us in accordance with our partnership agreement. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses incurred by or allocated to us as a result of being a separate publicly traded entity. We currently expect those expenses to be approximately $5.6 million per year, excluding equity-based compensation.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss), plus distributions from equity investee, interest expense, income tax expense and depreciation, less income from equity investments, interest income, income tax benefit and other income (expense). We believe that the presentation of Adjusted EBITDA provides information useful to investors in assessing our financial condition and results of operations and that Adjusted EBITDA is a widely accepted financial indicator of a company s ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA is a supplemental financial measure that management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash flow to make distributions; and
- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

Adjusted EBITDA is not defined in GAAP. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please see *Non-GAAP Financial Measures* in *Item 6 Selected Financial and Operating Data* of this Form 10-K.

Gross margin

We define gross margin as gathering, processing and transportation revenues, plus natural gas, natural gas liquids and condensate sales, less cost of product. We consider gross margin to provide information useful in assessing our results of operations, our ability to internally fund capital expenditures and to service or incur additional debt.

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ITEMS AFFECTING THE COMPARABILITY OF OUR FINANCIAL RESULTS

Our historical results of operations for the periods presented may not be comparable to future or historic results of operations for the reasons described below:

We anticipate incurring approximately $5.6 million of general and administrative expenses annually, excluding equity-based compensation expense, attributable to operating as a publicly traded entity, including expenses associated with annual and quarterly reporting; tax return and Schedule K-1 preparation and distribution expenses; expenses associated with listing on the New York Stock Exchange; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees; insurance premiums; and expenses associated with maintaining a limited accounting staff and facilities. General and administrative expenses such as these are reflected in our historical consolidated financial statements for periods including and subsequent to our initial public offering in May 2008.

Additionally, we anticipate incurring up to $6.65 million in general and administrative expenses annually to be charged by Anadarko to us pursuant to the omnibus agreement, which became effective in connection with our initial public offering. This amount is expected to be greater than amounts allocated to us by Anadarko for the management services fee reflected in our historical consolidated financial statements for periods prior to May 14, 2008.

Prior to May 14, 2008 with respect to our initial assets and prior to December 19, 2008 with respect to the Powder River assets, all affiliate transactions were net settled within our consolidated financial statements because these transactions related to Anadarko and were funded by Anadarko s working capital. Effective on May 14, 2008 with respect to our initial assets and December 19, 2008 with respect to the Powder River assets, all affiliate and third-party transactions are funded by our working capital. This impacts the comparability of our cash flow statements, working capital analysis and liquidity discussion.

Prior to May 14, 2008 with respect to our initial assets and prior to December 19, 2008 with respect to the Powder River assets, we incurred interest expense or earned interest income on intercompany balances with Anadarko. These intercompany balances were extinguished through non-cash transactions in connection with the closing of our initial public offering and the Powder River acquisition; therefore, interest expense and interest income attributable to these balances is reflected in our historical consolidated financial statements for the periods ending prior to and including May 14, 2008 with respect to our initial assets and prior to and including December 19, 2008 with respect to the Powder River assets.

In connection with the Powder River acquisition, we entered into a five-year, $175.0 million term loan agreement with Anadarko, under which we will pay interest at a fixed rate of 4.0% for the first two years and a floating rate of interest at three-month LIBOR plus 150 basis points for the final three years. For periods including and subsequent to the Powder River acquisition, interest expense on the $175.0 million note payable to Anadarko will be incurred so long as the loan agreement remains in place.

Concurrent with the closing of our initial public offering, we loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%. Interest income attributable to the note is reflected in our consolidated financial statements for the period beginning on May 14, 2008 and ending December 31, 2008 and will be included in future periods so long as the note remains outstanding.

Pursuant to the omnibus agreement, as a co-borrower under Anadarko s credit facility, we are required to reimburse Anadarko for our allocable portion of commitment fees (0.11% of our committed and available borrowing capacity, including our outstanding balances) that Anadarko incurs under its credit facility, or up to $110,000 per year. See *Note 6 Transactions with Affiliates* in the notes to the consolidated financial statements included in *Item 8 Financial Statements and Schedules* of this Form 10-K. In addition, Anadarko entered into a working capital facility with us, under which we incur an annual commitment fee of 0.11% of the unused portion of our committed borrowing capacity of $30.0 million, or up to $33,000 per year. These commitment fees are included in interest income (expense), net in our consolidated financial statements for the period beginning on May 14, 2008 and ending December 31, 2008 and will be included in future periods so long as the credit facilities are in place.

For periods ending prior to January 1, 2008, our consolidated financial statements reflect the gathering fees we historically charged Anadarko under our affiliate cost-of-service-based arrangements. Under these arrangements, we recovered, on an annual basis, our operation and maintenance, general and administrative and depreciation expenses in addition to earning a return on our invested capital. Effective January 1, 2008, we entered into new 10-year gas gathering agreements with Anadarko. Pursuant to the terms of the new agreements, our fees for gathering and treating services rendered to Anadarko increased. This increase was due, in part, to compensate us for additional operation and maintenance expense that we incur as a result of us bearing all of the cost of employee benefits specifically identified and related to operational personnel working on our assets, as compared to bearing only those employee benefit costs reasonably allocated by Anadarko to us for the periods ending prior to January 1, 2008. Because our new gas gathering agreements are designed to fully recover these incremental costs, our revenues increased by an amount approximately equal to the incremental operation and maintenance expense. Although this change in methodology for computing affiliate gathering rates does not impact our net cash flows or net income, this methodology change impacts the components thereof as compared to periods ending prior to January 1, 2008. If we applied the methodology employed under our new gas gathering agreements with Anadarko to the year ended December 31, 2007, we estimate our historic gathering revenues and operation and maintenance expense would have increased by $3.1 million and our cash flow from operations would have remained unchanged.

The 10-year gas gathering agreements entered into with Anadarko included new fees for gathering and treating. The new fees are based on capital improvements and changes in our cost-of-service analysis and are higher than those fees reflected in our historical financial results for the periods ended prior to January 1, 2008.

Our financial results for historical periods reflect commodity prices changes, which, in turn, impacts the financial results derived from our percent-of-proceeds processing contracts. Effective January 1, 2009, we have mitigated the commodity price risk associated with our percent-of-proceeds processing contracts by entering into fixed-price commodity price swap agreements with Anadarko that extend through at least December 31, 2010. See *Note 6 Transactions with Affiliates* of the notes to the consolidated financial statements included in *Item 8 Financial Statements and Supplementary Data* in this Form 10-K.

We are generally not subject to federal or state income tax. Federal and state income tax expense was recorded for periods ending prior to and including May 14, 2008 with respect to income generated by our initial assets and prior to and including December 19, 2008 with respect to income generated by the Powder River assets. In periods subsequent to May 14, 2008 with respect to income generated by our initial assets and subsequent to December 19, 2008 with respect to income generated by the Powder River assets, we are only subject to Texas margin tax; therefore, income tax expense attributable to Texas margin tax will continue to be recognized in our consolidated financial statements. We are required to make payments to Anadarko pursuant to a tax sharing arrangement for our share of Texas margin tax included in any combined or consolidated returns of Anadarko. The consolidated financial statements for periods ending prior to May 14, 2008 with respect to income generated by our initial assets and prior to December 19, 2008 with respect to income generated by the Powder River assets include deferred federal and state income taxes which were provided on temporary differences between the financial statement carrying amounts of recognized assets and liabilities and their respective tax bases as if we filed tax returns as a stand-alone entity. Immediately prior to closing of the dates of our initial public offering and the Powder River acquisition, we recorded an adjustment to equity of $76.5 million and $50.4 million, respectively, for the elimination of net deferred tax liabilities.

We currently make cash distributions to our unitholders and our general partner at an initial distribution rate of $0.30 per unit per full quarter ($1.20 per unit on an annualized basis). We paid cash distributions to our unitholders of $0.4582 per unit during the year ended December 31, 2008. This amount represents a $0.30 per unit quarterly distribution prorated for the 48-day period beginning on the date of our initial public offering and ending on June 30, 2008, or $0.1582 per unit, and a $0.30 per unit distribution for the quarter ended on September 30, 2008.

We expect that we will rely upon external financing sources, including commercial bank borrowings and debt and equity issuances, to fund our acquisition and expansion capital expenditures. Historically, we largely relied on internally generated cash flows and capital contributions from Anadarko to satisfy our capital expenditure requirements.

In connection with the closing of our initial public offering, our general partner adopted two new compensation plans; the Western Gas Partners, LP 2008 Long-Term Incentive Plan, or LTIP, and the Amended and Restated

Western Gas Holdings, LLC Equity Incentive Plan, or the Incentive Plan. Phantom unit grants have been made to each of the independent directors of our general partner under the LTIP, and incentive unit grants have been made to each of our general partner s executive officers under the Incentive Plan. Pursuant to Financial Accounting Standards Board Statement No. 123 (revised 2004), *Shared-Based Payment,* or SFAS 123(R), grants made under equity-based compensation plans result in equity-based compensation expense which is determined, in part, by reference to the fair value of equity compensation as of the date of grant. For periods ending prior to May 14, 2008, equity-based compensation expense attributable to the LTIP and Incentive Plan is not reflected in our historical consolidated financial statements as there were no outstanding equity grants under either plan. Effective as of May 14, 2008, equity-based compensation expense for grants made under the LTIP and Incentive Plan is reflected in our statements of operations. Share-based compensation expense attributable to grants made under the LTIP will impact our cash flows from operating activities only to the extent our general partner s board of directors, at its discretion, elects to make a cash payment to a participant in lieu of actual

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receipt of common units by the participant upon the lapse of the relevant vesting period. Equity-based compensation expense attributable to grants made under the Incentive Plan will impact our cash flow from operating activities only to the extent cash payments are made to Incentive Plan participants and such cash payments do not cause total annual reimbursements made by us to Anadarko pursuant to the omnibus agreement to exceed the general and administrative expense limit set forth therein for the periods to which such expense limit applies. See equity-based compensation discussion included in *Note 2 Summary of Significant Accounting Policies* and *Note 6 Transactions with Affiliates* of the notes to the consolidated financial statements included in *Item 8 Financial Statements and Supplementary Data* in this Form 10-K.

GENERAL TRENDS AND OUTLOOK

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expectations.

Capital markets

We require periodic access to capital in order to fund acquisitions and expansion projects. Under the terms of our partnership agreement, we are required to distribute all of our available cash to our unitholders, which makes us dependent upon raising capital to fund growth projects. Historically, master limited partnerships have accessed the public debt and equity capital markets to raise money for new growth projects. Recent market turbulence has either raised the cost of those public funds or, in some cases, eliminated the availability of these funds to prospective issuers. If we are unable either to access the public capital markets or find alternative sources of capital, our growth strategy may be more challenging to execute.

Impact of interest rates

Interest rates have been volatile in recent periods. If interest rates rise, our future financing costs could increase accordingly. In addition, because our common units are yield-based securities, rising market interest rates could impact the relative attractiveness of our common units to investors, which could limit our ability to raise funds, or increase the cost of raising funds, in the capital markets. Though our competitors may face similar circumstances, such an environment could adversely impact our efforts to expand our operations or make future acquisitions.

Natural gas supply and demand

Natural gas continues to be a critical component of energy supply in the U.S. According to the Energy Information Administration, or EIA, total annual domestic consumption of natural gas is expected to decrease from approximately 23.4 Tcf in 2008 to approximately 22.5 Tcf in 2011, but consumption is expected to increase to approximately 24.5 Tcf by 2028. During the last three years, the U.S. has, on average, consumed approximately 22.7 Tcf per year, while total domestic production averaged approximately 19.4 Tcf per year during the same period. Overall, natural gas reserves in the U.S. have increased in recent years, based on data obtained from the EIA.

There is a natural decline in production from existing wells. Although in the areas in which we operate there has been a significant level of drilling activity offsetting this decline in recent years, the current natural gas price environment has resulted in significantly lower drilling activity throughout areas in which we operate and drilling activity in certain areas could be temporarily suspended. We have no control over this activity. In addition, the recent or further decline in commodity prices could affect production rates and the level of investment by Anadarko and third parties in the exploration for and development of new natural gas reserves.

Rising operating costs and inflation

The high level of natural gas exploration, development and production activities across the U.S. in recent years, and the associated construction of required midstream infrastructure, resulted in increased competition for personnel and equipment. Although the activities have slowed in recent months, we have not yet realized a material decline in the prices we pay for labor, supplies and property, plant and equipment. An increase in the general level of prices in the economy could have a similar effect. We have the ability to recover increased costs from our customers through escalation provisions provided for in our contracts. However, there may be a delay in recovering these costs or we may be unable to recover all these costs. To the extent we are unable to recover higher costs our operating results will be negatively impacted.

Benefits from system expansions

We expect that expansion projects, including the following, will position us to capitalize on future drilling activity by Anadarko and third-party producers and shippers:

We modified and relocated horsepower on our Dew system during the third quarter of 2008, which resulted in lower gathering line pressures and an increase in throughput of approximately 2 MMcf/d.

Further modifications of compression on our Dew system are planned for 2009 which are expected to result in lower gathering line pressures servicing the Holly Branch producing area and may further increase throughput by up to approximately 2 MMcf/d.

We expanded our Bethel treating facility by installing an additional 11 LTD of sulfur treating capacity in order to provide additional sour gas treating capacity for drilling in the area, which we completed in July 2008.

We are expanding our Hugoton gathering system to connect wells drilled by third parties and Anadarko. During 2008, we connected 12 third-party wells with an average initial production rate of 2.8 MMcf/d. We also connected 8 new Anadarko wells and reconnected 6 others that were previously connected to third-party gathering systems. These 14 wells collectively produced at a rate of 1.9 MMcf/d during the month of December 2008.

In November 2007, Anadarko completed Phase II of the Fort Union expansion project by installing 42 miles of 24 pipe, bringing the total header system to two parallel 24 lines stretching 106 miles in length. During 2008, Anadarko completed Phase III of the Fort Union expansion project by installing a third parallel 106-mile 24 line, increasing the total Fort Union handling capacity to 1,300 MMcf/d.

Anadarko expanded train one of the Medicine Bow Plant at the terminus of the Fort Union gathering system in March 2007, increasing the total amine circulation capacity to 300 gal/min and increasing the system s gas treating capability to 70 MMcf/d of gas containing 3.2% CO_2. During the fourth quarter of 2008, we completed train two, which has 600 gal/min of amine circulation and a gas treating capacity of 112 MMcf/d of gas containing 4.5% CO_2. Train three, which is identical to train two, is currently under construction and is expected to begin operations in the first quarter of 2009. Upon the completion of train three, we expect to have sufficient treating capacity to meet the CO_2 specifications of downstream pipelines in the future.

Acquisition opportunities

A key component of our growth strategy is to acquire midstream assets from Anadarko over time. In December 2008, we acquired the Powder River assets from Anadarko. As of December 31, 2008, Anadarko s total domestic midstream asset portfolio, excluding assets we own, consisted of 19 gathering systems with an aggregate throughput of approximately 2.3 Bcf/d, 8,100 miles of pipeline and 18 processing and/or treating facilities. Anadarko owns a 2.0% general partner interest in us, all of our IDRs and a 61.3% limited partner interest in us. Given Anadarko s significant interests in us, we believe Anadarko will benefit from selling additional assets to us over time; however, Anadarko continually evaluates acquisitions and divestitures and may elect to acquire, construct or dispose of midstream assets in the future without offering us the opportunity to acquire or construct those assets. Should Anadarko choose to pursue additional midstream asset sales, it is under no contractual obligation to offer assets or business opportunities to us. We may also pursue selected asset acquisitions from third parties to the extent such acquisitions complement our or Anadarko s existing asset base or allow us to capture operational efficiencies from Anadarko s or third-party production. However, if we do not make additional acquisitions from Anadarko or third parties on economically acceptable terms, our future growth will be limited, and the acquisitions we make could reduce, rather than increase, our cash generated from operations on a per-unit basis.

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RESULTS OF OPERATIONS OVERVIEW
OPERATING RESULTS

The following table and discussion presents a summary of our results of operations for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007[1]**	**2006[1]**
		(in thousands)	
Revenues affiliates			
Gathering, processing and transportation of natural gas	$ 107,582	$ 93,007	$ 66,296
Natural gas, natural gas liquids and condensate sales	154,772	146,151	52,959
Equity income and other	9,289	6,144	2,380
Total revenues affiliates	271,643	245,302	121,635
Revenues third parties			
Gathering, processing and transportation of natural gas	15,958	11,019	5,783
Natural gas, natural gas liquids and condensate sales	16,119	2,772	3
Other	7,928	2,400	1,189
Total revenues third parties	40,005	16,191	6,975
Total Revenues	311,648	261,493	128,610
Operating Expenses [2]			
Cost of product	134,715	112,283	41,806
Operation and maintenance	44,765	40,756	29,907
General and administrative	14,385	8,364	4,320
Property and other taxes	5,701	5,591	4,719
Depreciation and impairment	42,365	30,481	20,230
Total Operating Expenses	241,931	197,475	100,982
Operating Income	69,717	64,018	27,628
Interest income (expense), net affiliates	9,191	(7,805)	(9,574)
Other income (expense), net	145	(15)	(26)
Income Before Income Taxes	79,053	56,198	18,028
Income Tax Expense	13,777	19,540	5,327
Net Income	$ 65,276	$ 36,658	$ 12,701
Adjusted EBITDA[3]	$ 112,474	$ 91,830	$ 47,239
Gross margin[3]	159,716	140,666	83,235

(1) Financial information for 2007 and 2006 has been revised to include results attributable to the Powder River assets from August 23, 2006. See *Note 3 Powder River Acquisition* of the notes to the consolidated financial statements in *Item 8 Financial Statements and Supplementary Data*.

(2) Operating expenses include amounts charged by affiliates to the Partnership for services as well as reimbursement of amounts paid by affiliates to third parties on behalf of the Partnership. *See Note 6 Transactions with Affiliates* of the notes to the consolidated financial statements in *Item 8 Financial Statements and Supplementary Data.*

(3) Adjusted EBITDA and gross margin are

defined above within this *Item 7* under the caption *How We Evaluate Our Operations. Item 6 Selected Financial and Operating Data*, includes a reconciliation of Adjusted EBITDA to its most directly comparable measures calculated and presented in accordance with GAAP.

For purposes of the following discussion, any increases or decreases for the year ended December 31, 2008 refer to the comparison of the year ended December 31, 2008 to the year ended December 31, 2007. Similarly, any increases or decreases for the year ended December 31, 2007 refer to the comparison of the year ended December 31, 2007 to the year ended December 31, 2006.

Executive Summary

Total revenues increased by $50.2 million and $132.9 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. Gathering, processing and transportation revenues increased $19.5 million; natural gas, NGLs and condensate revenues increased $22.0 million and equity income and other revenues increased $8.7 million for the year ended December 31, 2008. Gathering, processing and transportation revenues increased $31.9 million; natural gas,

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NGLs and condensate revenues increased $96.0 million and equity income and other revenues increased $5.0 million for the year ended December 31, 2007. Revenues attributable to MIGC and the Powder River assets contributed to $110.0 million of the increase in total revenues for the year ended December 31, 2007. This distinction bears significance for all comparisons for the year ended December 31, 2007 in that results attributable to these assets for 2006 include only the results from August 23, 2006, the date Anadarko acquired Western.

Net income increased by $28.6 million and $24.0 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. The increase in net income for the year ended December 31, 2008 is primarily due to a $50.2 million increase in total revenues driven by gathering rate increases, increased condensate margins, an increase in other revenues from changes in gas imbalance positions and gas prices, a $17.0 million increase in net affiliate interest income and a $5.8 million decrease in income tax expense. These items are partially offset by higher operating expenses of $44.5 million for the year ended December 31, 2008.

For the year ended December 31, 2007, the increase in net income of $24.0 million is primarily due to a $132.9 million increase in total revenues attributable to acquisitions, gathering rate increases, increased condensate margins and an increase in equity income and other revenues from changes in gas imbalance positions and gas prices, and a $1.8 million decrease in net affiliate interest expense. These items are partially offset by higher operating expenses of $96.5 million and increased income tax expense of $14.2 million. MIGC and the Powder River assets contributed to $16.5 million of the increase in net income for the year ended December 31, 2007. The changes in revenues, operating expenses, interest expense and income taxes are discussed in more detail below.

Revenues and Operating Statistics

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, except per-unit data and percents)				
Revenues					
Affiliates	$ 271,643	$ 245,302	11%	$ 121,635	102%
Third parties	40,005	16,191	147%	6,975	132%
Total revenues	$ 311,648	$ 261,493	19%	$ 128,610	103%
Gathering and transportation throughput (MMcf/d)[(a)]					
Affiliates	831	917	(9%)	891	3%
Third parties	135	90	50%	80	13%
Total throughput	966	1,007	(4%)	971	4%
Processing throughput (MMcf/d)					
Affiliates					
Third parties	30	30	0%	30	(0%)
Total throughput	30	30	0%	30	(0%)
Gross margin per MMcf [(b)]	$ 0.44	$ 0.37	19%	$ 0.23	61%

(a) Throughput volumes exclude Fort

Union volumes.

(b) Calculated using gathering, processing and transportation of natural gas revenues and natural gas, natural gas liquids and condensate sales, less cost of product. Processing volumes originate from third parties while the related residue natural gas and natural gas liquids are sold to an affiliate, therefore the gross margin per MMcf calculated separately for affiliates and third parties is not meaningful.

Throughput volumes, which consist of affiliate and third-party volumes, decreased by 41,000 Mcf/d for the year ended December 31, 2008 and increased by 36,000 Mcf/d for the year ended December 31, 2007.

Affiliate gathering and transportation volumes decreased by 86,000 Mcf/d for the year ended December 31, 2008, primarily attributable to throughput decreases at the Haley, Pinnacle, Hugoton and Dew systems, partially offset by increases at the MIGC system. Haley field production and related Haley system throughput peaked in the first quarter of 2007. Since the first quarter of 2007, production and associated volumes from the Haley field have gradually declined due to the natural production decline and a shift in rig activity from the dedicated gathering area to other exploration areas within the Delaware Basin, resulting in fewer well connections. Recent activity has partially offset volume declines at the Haley system, with 13 wells connected during the year ended December 31, 2008, in addition to the third-party volumes described below. The decline in affiliate volumes at the Hugoton, Dew and Pinnacle systems for the year ended December 31, 2008 is primarily due to natural production declines and reduced or delayed activity in the Dew and Pinnacle areas. These volume decreases are partially offset by increases in the MIGC system due to a new affiliate contract that became effective in September 2007 in connection with expansion of the system s capacity.

Affiliate gathering and transportation volumes increased by 26,000 Mcf/d for the year ended December 31, 2007, primarily attributable to increases in volumes at the Haley and MIGC systems, partially offset by decreases at the Dew system.

Third-party gathering and transportation volumes increased by 45,000 Mcf/d for the year ended December 31, 2008, primarily attributable to the throughput increases at the Haley and Hugoton systems, partially offset by throughput declines at the Pinnacle system resulting primarily from a decrease in volumes at two central receipt points from a large third-party shipper. The increase in third-party volumes at the Haley gathering system is primarily due to a third party s activity in the area. Increased volumes at the Hugoton system are due to a third-party customer s successful drilling program, which resulted in 12 additional wells being connected to the Hugoton gathering system during the year ended December 31, 2008.

Third-party gathering and transportation volumes increased by 10,000 Mcf/d for the year ended December 31, 2007, primarily attributable to throughput increases at the Hugoton system.

Processing volumes remained flat for the year ended December 31, 2008 and for the year ended December 31, 2007.

Gathering, Processing and Transportation of Natural Gas Revenues

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, except percents)				
Gathering, processing and transportation of natural gas:					
Affiliates	$ 107,582	$ 93,007	16%	$ 66,296	40%
Third parties	15,958	11,019	45%	5,783	91%
Total	$ 123,540	$ 104,026	19%	$ 72,079	44%

Total gathering, processing and transportation of natural gas revenues increased by $19.5 million and $31.9 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. Revenues from affiliates increased $14.6 million for the year ended December 31, 2008 primarily due to an increase in affiliate gathering rates under new contracts that became effective January 1, 2008, partially offset by lower volumes. Revenues from third parties for the year ended December 31, 2008 increased $4.9 million primarily due to an increase in volumes on the Haley and Hugoton systems.

Gathering, processing and transportation revenues from affiliates for the year ended December 31, 2007 increased $26.7 million as a result of the acquisition of the MIGC system in August 2006, increasing rates in all the gathering systems and increased volumes, primarily in the Haley and Pinnacle systems. Third-party gathering, processing and transportation revenues for the year ended December 31, 2007 increased $5.2 million primarily as a result of the acquisition of the MIGC system in August 2006 and receipt of a $1.1 million payment for a volume commitment.

Natural Gas, Natural Gas Liquids and Condensate Sales

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, except percents)				
Natural gas sales:					
Affiliates	$ 56,887	$ 42,302	34%	$ 16,963	149%
Third parties	23		nm(1)		
Total	$ 56,910	$ 42,302	35%	$ 16,963	149%
Natural gas liquids sales affiliates:	$ 97,885	$ 96,795	1%	$ 28,556	239%
Drip condensate sales:					
Affiliates	$	$ 7,054	(100%)	$ 7,440	(5%)
Third parties	16,096	2,772	481%	3	nm
Total	$ 16,096	$ 9,826	64%	$ 7,443	32%
Total natural gas, natural gas liquids and condensate sales:					
Affiliates	$ 154,772	$ 146,151	6%	$ 52,959	176%
Third parties	16,119	2,772	481%	3	nm
Total	$ 170,891	$ 148,923	15%	$ 52,962	181%

(1) Not meaningful

Total natural gas, natural gas liquids and condensate sales increased by $22.0 million and $96.0 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively.

The increase in natural gas sales for the year ended December 31, 2008 was primarily due to an increase in the average price for residue sold from $5.24 per Mcf to $7.62 per Mcf. The volume of natural gas sold was relatively flat for the year ended December 31, 2008. The increase for year ended December 31, 2007 is primarily due to including revenues attributable to the Hilight and Newcastle systems for the full year of 2007 compared to only a partial year for 2006, partially offset by a decrease in prices from $5.62 per Mcf to $5.24 per Mcf for the year ended December 31, 2007.

The increase in NGLs sales for the year ended December 31, 2008 was primarily due to an increase in the average price from $57.43 per Bbl to $73.75 per Bbl of liquids sold. The volume of NGLs decreased approximately 712 Bbls/d for the year ended December 31, 2008. The increase for year ended December 31, 2007 is primarily due to including revenues attributable to the Hilight and Newcastle systems for the full year of 2007 compared to only a partial year for 2006. In addition, prices increased from $50.24 per Bbl to $57.43 per Bbl of liquids for the year ended December 31, 2007. Sales of plant condensate are included in NGLs sales.

The increase in drip condensate sales was primarily due to increased average condensate prices, which were $89.34 per Bbl for the year ended December 31, 2008, $64.43 per Bbl for the year ended December 31, 2007 and $58.84 per Bbl for the year ended December 31, 2006. Drip condensate volumes increased approximately 77 Bbls/d and 66 Bbls/d for the years ended December 31, 2008 and December 31, 2007, respectively. The volume increases for the years is primarily attributable to an increase in condensate recoveries due to the higher Btu composition of the gas stream from third-party drilling activity that has offset production declines. The change from affiliate revenues to third-party revenues is attributable to a November 2007 contract modification which effectively converted all of our condensate sales for 2008 to third-party sales.

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Equity Income and Other Revenues

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, except percents)				
Equity income affiliate	$ 4,736	$ 4,017	18%	$ 1,360	195%
Other revenues:					
Affiliates	$ 4,553	$ 2,127	114%	$ 1,020	109%
Third parties	7,928	2,400	230%	1,189	102%
Total equity and other revenues	$ 17,217	$ 8,544	102%	$ 3,569	139%

Total equity income and other revenues increased by $8.7 million and $5.0 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. The increase for the year ended December 31, 2008 is primarily due to changes in our natural gas imbalance positions primarily due to higher gas prices, which accounted for $6.7 million of the increase, and a $0.7 million increase in equity income from our investment in Fort Union. The increase for the year ended December 31, 2007 is primarily due to income from Fort Union, which is included for the full year for 2007 compared to only four and half months for 2006, and changes in our gas imbalance positions primarily due to higher gas prices.

Cost of Product and Operation and Maintenance Expenses

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, except percents)				
Cost of product	$ 134,715	$ 112,283	20%	$ 41,806	169%
Operation and maintenance	44,765	40,756	10%	29,907	36%
Total cost of product and operation and maintenance expenses	$ 179,480	$ 153,039	17%	$ 71,713	113%

Cost of product for the year ended December 31, 2008 and for the year ended December 31, 2007 increased by $22.4 million and $70.5 million, respectively. Cost of product is impacted by natural gas and NGLs we purchase from producers and also for the cost of natural gas that we redeliver to shippers to compensate them on a thermally equivalent basis for condensate retained by us and sold to third parties. Gas purchases from producers for natural gas averaged $6.23 per Mcf, $4.29 per Mcf and $4.16 per Mcf for the years ended December 31, 2008, 2007 and 2006, respectively. Gas purchases from producers for NGLs averaged $50.81 per Bbl, $42.65 per Bbl and $37.14 per Bbl for the years ended December 31, 2008, 2007 and 2006, respectively. Gas purchases for plant condensate averaged $6.94 per Mcf, $6.09 per Mcf and $6.19 per Mcf for the years ended December 31, 2008, 2007 and 2006, respectively. The increase in cost of product for 2008 was primarily attributable to the increase cost of natural gas and NGLs and the cost to settle gas imbalances associated with MIGC. The increase in cost of product for 2007 was primarily attributable to having a full year of cost for MIGC and the Powder River assets compared to a partial year for 2006, partially offset by an increase in average price per unit purchased. Cost of product expense includes natural gas purchases from affiliates of $23.6 million, $18.8 million and $8.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Operation and maintenance expense for the year ended December 31, 2008 and for the year ended December 31, 2007 increased by $4.0 million and $10.8 million, respectively. For the year ended December 31, 2008, labor and employee-related expenses increased by approximately $6.5 million primarily attributable to being charged by Anadarko for the full cost of these expenses. Specifically, contract modifications, beginning in 2008, entitled Anadarko to charge us additional labor and employee-related expenses in order for us to bear the full cost of operational personnel working on our assets instead of bearing only those employee benefit costs reasonably allocated by Anadarko to us. These additional costs were taken into account when setting the gathering rates in our affiliate-based contracts that became effective in January 2008; thus, our revenues increased by approximately the same amount. In addition, other increases in labor and employee-related expenses for the year ended December 31, 2008 were due to increases in benefits and incentive programs. These increases are partially offset by decreases in compressor expenses of $2.6 million. For the year ended

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December 31, 2007, the increase in operations and maintenance expense is primarily attributable to the acquisition of MIGC and the Powder River acquisition. Operation and maintenance expenses include charges from affiliates of $19.2 million, $11.7 million and $1.7 million for the years ended December 31, 2008, 2007 and 2006, respectively, for services provided to the Partnership pursuant to the services and secondment agreement for periods subsequent to the initial public offering and for personnel costs allocated by Anadarko to us for periods prior to May 14, 2008 with respect to the initial assets and prior to December 1, 2008 with respect to the Powder River assets.

Gross Margin

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, except percents)				
Gross margin	$ 159,716	$ 140,666	14%	$ 83,235	69%

Gross margin increased $19.1 million for the year ended December 31, 2008 and increased $57.4 million for the year ended December 31, 2007 due to the increases in total revenues partially offset by the increases in cost of product expense, which are described above.

General and Administrative, Depreciation, Impairment and Other Expenses

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, except percents)				
General and administrative	$ 14,385	$ 8,364	72%	$ 4,320	94%
Property and other taxes	5,701	5,591	2%	4,719	19%
Depreciation and impairment	42,365	30,481	39%	20,230	51%
Total general and administrative, depreciation and other expenses	$ 62,451	$ 44,436	41%	$ 29,269	52%

General and administrative, depreciation, impairment and other expenses increased by $18.0 million and $15.2 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. The increases are partially attributable to an increase in general and administrative expenses of $6.0 million and $4.0 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. The general and administrative expense increase in 2008 is primarily due to increased expenses of $3.0 million attributable to being a publicly traded entity, $2.2 million attributable to equity-based compensation expense and $1.5 million of direct costs attributable to the Powder River transaction, partially offset by a decrease in expenses charged pursuant to the management services fee prior to May 14, 2008. Expenses attributable to being a publicly traded entity are comprised of consulting and auditing fees, expenses attributable to accounting personnel dedicated to the operations of the Partnership, legal expenses and director fees. For 2007, the increase in general and administrative expenses is primarily attributed to MIGC and the Powder River assets, which are included for the full year for 2007 compared to only four and a half months for 2006.

Subsequent to May 14, 2008 general and administrative expenses were charged to us by Anadarko pursuant to the omnibus agreement, which became effective on May 14, 2008. For periods prior to May 14, 2008 with respect to the initial assets and December 1, 2008 with respect to the Powder River assets, general and administrative expenses included costs allocated by Anadarko to the Partnership in the form of a management services fee. General and administrative expenses include charges from affiliates of $11.0 million, $8.4 million and $4.3 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Property and other taxes increased by $110,000 and $872,000 for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively, primarily due to higher ad valorem taxes. Depreciation and impairment expense increased by $11.9 million and $10.3 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. The increased depreciation and impairment expense for the year ended December 31, 2008 is primarily attributable to a $9.4 million impairment expense recognized in connection with the shut-in of a plant in the Hilight System prior to our Powder River acquisition and depreciation on additional assets placed into service during 2008, including an 11-ton Lo-cat project at the Pinnacle system. The increased depreciation and impairment expense for the year ended December 31, 2007 is primarily attributable to depreciation expense on the MIGC pipeline and the Powder River assets, which is included for the full year for 2007 compared to a partial year for 2006 and for other assets placed in service during the second half of 2006 and 2007 at the Haley and Hugoton systems.

Interest Income (Expense), Net Affiliates

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, percents)				
Interest income on note receivable from Anadarko	$ 10,703	$	100%	$	
Interest (expense) on note payable to Anadarko	(253)		100%		
Interest (expense), net affiliates	(1,259)	(7,805)	(84%)	(9,574)	(18%)
Total interest income (expense), net affiliates	$ 9,191	$ (7,805)	218%	$ (9,574)	(18%)

We earned net interest income for the year ended December 31, 2008 as compared to incurring net interest expense for the years ended December 31, 2007 and 2006. Interest income (expense), net consists of interest income on our $260.0 million note receivable from Anadarko for periods subsequent to May 14, 2008, offset by interest expense charged on affiliate balances for periods prior to May 14, 2008 with respect to the initial assets and prior to December 19, 2008 with the respect to the Powder River assets, as well as interest expense attributable to our $175.0 million term loan agreement entered into with Anadarko in connection with our the Powder River acquisition and commitment fees on our portion of Anadarko s $1.3 billion credit facility and our $30.0 million working capital facility for periods subsequent to May 14, 2008. The net changes in interest income (expense) are $17.0 million and $1.8 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. These changes are primarily due to the items described above.

Income Tax Expense

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, except percents)				
Income before income taxes	$ 79,053	$ 56,198	41%	$ 18,028	212%
Income tax expense	13,777	19,540	(30%)	5,327	267%
Effective tax rate	17%	35%		30%	

For the year ended December 31, 2008 and for the year ended December 31, 2007, income tax expense decreased by approximately $5.8 million and increased approximately $14.2 million, respectively. The decrease in income tax expense for the year ended December 31, 2008 is primarily due to the Partnership s U.S. federal income tax status as a non-taxable entity for the period beginning on May 14, 2008 and ending on December 31, 2008, partially offset by an increase in income before income tax earned prior to May 14, 2008, which is subject to federal and state income tax. Income earned by the Partnership attributable to the initial assets after May 14, 2008 is subject only to Texas margin tax. The increase in income tax expense for the year ended December 31, 2007 is primarily due to inclusion of income taxes attributable to MIGC and the Powder River assets for the full year for 2007 compared to only four and a half months for 2006.

For 2008, the variance from the 35% federal statutory rate is primarily attributable to the Partnership s income attributable to the initial assets being subject only to Texas margin tax for the period beginning on May 14, 2008 and ending on December 31, 2008. For 2006, the variance from the 35% federal statutory rate is primarily attributable to state income tax. The effective tax rates for 2007 and 2006 include an increase to the 35% statutory rate attributable to state income tax expense, offset by a reduction in state income tax expense resulting from enacted Texas legislation. Texas House Bill 3, signed into law in May 2006, eliminated the taxable capital and earned surplus components of the existing franchise tax and replaced these components with a taxable margin tax calculated on a combined group-reporting basis. We were required to include the impact of the new law in income for the period which included the date of the law s enactment. The adjustment, a reduction in deferred state income taxes in the amount of approximately $0.4 million and $1.1 million (net of federal tax benefit), was included in 2007 and 2006 income tax expense, respectively.

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LIQUIDITY AND CAPITAL RESOURCES

Our ability to finance operations, fund maintenance capital expenditures and pay distributions will largely depend on our ability to generate sufficient cash flow to cover these requirements. Our ability to generate cash flow is subject to a number of factors, some of which are beyond our control. Please read *Item 1A Risk Factors* of this Form 10-K.

Prior to our initial public offering, our sources of liquidity included cash generated from operations and funding from Anadarko. Furthermore, we had participated in Anadarko s cash management program, whereby Anadarko, on a periodic basis, swept cash balances residing in our bank accounts. Thus, our historical consolidated financial statements for periods ending prior to our initial public offering reflect no significant cash balances. Unlike our transactions with third parties, which ultimately are settled in cash, our affiliate transactions were settled on a net basis through an adjustment to parent net equity. Subsequent to our initial public offering, we maintain our own bank accounts and sources of liquidity. Although we continue to utilize Anadarko s cash management system, our cash accounts are not subject to cash sweeps with Anadarko s cash accounts.

Our current sources of liquidity include:

- approximately $29.0 million of working capital as of December 31, 2008, which we define as the amount by which current assets exceed current liabilities;
- cash generated from operations;
- available borrowings of up to $100.0 million under Anadarko s credit facility;
- available borrowings under our $30.0 million working capital facility with Anadarko;
- interest income from our $260.0 million note receivable from Anadarko;
- issuances of additional partnership units; and
- debt offerings.

We believe that cash generated from these sources will be sufficient to satisfy our short-term working capital requirements and long-term capital expenditure requirements. The amount of future distributions to unitholders will depend on earnings, financial conditions, capital requirements and other factors, and will be determined by the board of directors of our general partner on a quarterly basis.

Working capital

Working capital, defined as the amount by which current assets exceed current liabilities, is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven by changes in accounts receivable and accounts payable. These changes are primarily impacted by factors such as credit extended to, and the timing of collections from, our customers and our level of spending for maintenance and expansion activity.

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Historical cash flow

The following table and discussion presents a summary of our net cash provided by operating activities, net cash used in investing activities, net cash used in financing activities and Adjusted EBITDA for the years ended December 31, 2008, 2007 and 2006.

For the period January 1, 2008 to May 13, 2008, our net cash from operating activities and capital contributions from our parent were used to service our cash requirements, which included the funding of operating expenses and capital expenditures. Subsequent to May 14, 2008 with respect to our initial assets and December 19, 2008 with respect to the Powder River assets, transactions with Anadarko are cash-settled.

	2008	2007	2008 vs. 2007	2006	2007 vs. 2006
	(in thousands, except percents)				
Net cash provided by (used in):					
Operating activities	$ 109,796	$ 72,908	51%	$ 33,304	119%
Investing activities	(479,959)	(54,328)	783%	(42,963)	26%
Financing activities	403,469	(19,038)	nm[1]	10,113	nm
Net increase (decrease) in cash and cash equivalents	$ 33,306	$ (458)	nm	$ 454	nm
Adjusted EBITDA	$ 112,474	$ 91,830	22%	$ 47,239	94%

(1) Not meaningful

For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read *Non-GAAP Financial Measures* in *Item 6 Selected Financial and Operating Data* of this Form 10-K.

Operating Activities. Net cash provided by operating activities increased by $36.9 million and $39.6 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. The increase in net cash provided by operating activities for the year ended December 31, 2008 is primarily attributable to gathering rate increases, increased condensate margins, revenues attributable to changes in gas imbalance positions and gas prices as well as increased net interest income. These items are partially offset by higher cash operating expenses. Additionally, changes in working capital decreased cash flows from operating activities. The increase in net cash provided by operating activities for the year ended December 31, 2007 is primarily attributable to the cash flows from MIGC and the Powder River assets, which are included for the full year for 2007 compared to a partial year for 2006.

Investing Activities. Net cash used in investing activities increased by $425.6 million and $11.4 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. The increase for the year ended December 31, 2008 is primarily attributable to our $260.0 million loan made to Anadarko in connection with the initial public offering, the $175.0 million of cash paid for the Powder River acquisition and $8.1 million for additional investment in Fort Union, partially offset by a $17.5 million decrease in capital expenditures. The increase for the year ended December 31, 2007 is attributable to higher capital expenditures.

Financing Activities. Net cash provided by financing activities increased by $422.5 million and decreased by $29.2 million for the year ended December 31, 2008 and for the year ended December 31, 2007, respectively. This increase for the year ended December 31, 2008 is primarily attributable to the receipt of $315.2 million of net proceeds from the initial public offering, $175.0 million of loan proceeds attributable to our term loan agreement with Anadarko which was entered in connection with the Powder River acquisition, and a $2.3 million decrease in net distributions to Anadarko. These amounts were partially offset by $45.2 million of reimbursements to our Parent from offering proceeds and $24.8 million of cash distributions to unitholders. The decrease for the year ended December 31, 2007 is attributable to an increase in net distributions to Anadarko.

Adjusted EBITDA. Adjusted EBITDA for the year ended December 31, 2008 and for the year ended December 31, 2007 increased by $20.6 million and $44.6 million, respectively. The increase for the year ended December 31, 2008 is primarily due to a $50.2 million increase in total revenues and a $3.8 million increase in distributions from Fort Union, partially offset by a $22.4 million increase in cost of product, a $4.0 million increase in operation and maintenance expenses and a $6.0 million increase in general and administrative expenses, all of which are discussed above. The increase for the year ended December 31, 2007 is primarily due to a $132.9 million increase in total revenues and a $607,000 increase in distributions from Fort Union, partially offset by a $70.5 million increase in cost of product, a $10.8 million increase in operation and maintenance expenses, a $4.0 million increase in general and administrative expenses and a $0.9 million increase in property and other taxes, all of which are discussed above.

Capital requirements

Our business can be capital intensive, requiring significant investment to maintain and improve existing facilities. We categorize capital expenditures as either:

- maintenance capital expenditures, which include those expenditures required to maintain the existing operating capacity and service capability of our assets, including the replacement of system components and equipment that have suffered significant wear and tear, become obsolete or approached the end of their useful lives, those expenditures necessary to remain in compliance with regulatory or legal requirements or those expenditures necessary to complete additional well connections to maintain existing system volumes and related cash flows; or

- expansion capital expenditures, which include those expenditures incurred in order to extend the useful lives of our assets, increase gathering, processing, treating and transmission throughput from current levels, reduce costs or increase revenues.

Total capital expenditures for the years ended December 31, 2008, 2007 and 2006 were $36.9 million, $54.3 million and $43.0 million, respectively. For 2007 and 2006, we did not differentiate between maintenance and expansion capital expenditures. For the year ended December 31, 2008, expansion capital expenditures represented approximately 53% of total capital expenditures. We estimate our total capital expenditures, excluding acquisitions (if any), to be $27.0 million to $31.0 million and our maintenance capital expenditures to be approximately half of total capital expenditures for the twelve months ending December 31, 2009. Our future expansion capital expenditures may vary significantly from period to period based on the investment opportunities available to us, which are dependent, in part, on the drilling activities of Anadarko and third-party producers. From time to time, for projects with significant risk or capital exposure, we may secure indemnity provisions or throughput agreements. We expect to fund future capital expenditures from cash flows generated from our operations, interest income from our note receivable from Anadarko, borrowings under Anadarko s credit facility, the issuance of additional partnership units or debt offerings.

Distributions

We expect to pay a minimum quarterly distribution of $0.30 per unit per full quarter, which equates to approximately $17.0 million per full quarter, or approximately $68.1 million per full year, based on the number of common, subordinated and general partner units outstanding as of December 31, 2008. We do not have a contractual obligation to pay distributions. On January 28, 2009, the board of directors of our general partner declared a cash distribution to our unitholders of $0.30 per unit, which was paid on February 13, 2009 to unitholders of record at the close of business on January 30, 2009. In addition, we paid cash distributions to our unitholders of $0.4582 per unit during the year ended December 31, 2008. This amount represents a $0.30 per unit quarterly distribution prorated for the 48-day period beginning on May 14, 2008 and ending on June 30, 2008, or $0.1582 per unit, and a $0.30 per unit distribution for the quarter ended on September 30, 2008. See *Note 4 Partnership Equity and Distributions* of the notes to the consolidated financials statements included in *Item 8 Financial Statements and Supplementary Data* in this Form 10-K.

Our borrowing capacity under Anadarko s credit facility

On March 4, 2008, Anadarko entered into a $1.3 billion credit facility under which we are a co-borrower. This credit facility is available for borrowings and letters of credit and permits us to borrow up to $100.0 million under the facility for general partnership purposes, including acquisitions, but only to the extent that sufficient amounts remain unborrowed by Anadarko and its other subsidiaries. At December 31, 2008, the full $100.0 million was available for borrowing by us. The $1.3 billion credit facility expires in March 2013.

Interest on borrowings under the credit facility is calculated based on the election by the borrower of either: (i) a floating rate equal to the federal funds effective rate plus 0.50% or (ii) a periodic fixed rate equal to LIBOR plus an applicable margin. The applicable margin, which was 0.44% at December 31, 2008, and the commitment fees on the facility are based on Anadarko s senior unsecured long-term debt rating. Pursuant to the omnibus agreement, as a co-borrower under Anadarko s credit facility, we are required to reimburse Anadarko for our allocable portion of commitment fees (0.11% of our committed and available borrowing capacity, including our outstanding balances) that Anadarko incurs under its credit facility, or up to $110,000 annually. Under the credit facility, we and Anadarko are required to comply with certain covenants, including a financial

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covenant that requires Anadarko to maintain a debt-to-capitalization ratio of 65% or less. As of December 31, 2008, we and Anadarko were in compliance with all covenants. Should we or Anadarko fail to comply with any covenant in Anadarko s credit facility, we may not be permitted to borrow thereunder. Anadarko is a guarantor of all borrowings under the credit facility, including our borrowings. We are not a guarantor of Anadarko s borrowings under the credit facility.

Our working capital facility

Concurrent with the closing of our initial public offering, we entered into a two-year, $30.0 million working capital facility with Anadarko as the lender. At December 31, 2008, no borrowings were outstanding under the working capital facility. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility will bear interest at the same rate as would apply to borrowings under the Anadarko credit facility described above. We pay a commitment fee of 0.11% annually to Anadarko on the unused portion of the working capital facility, or up to $33,000 annually.

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

Credit risk

We bear credit risk represented by our exposure to non-payment or non-performance by our customers, including Anadarko. Generally, non-payment or non-performance results from a customer s inability to satisfy receivables for services rendered or volumes owed pursuant to gas imbalance agreements. We examine the creditworthiness of third-party customers and may establish credit limits for significant third-party customers.

We are dependent upon a single producer, Anadarko, for the majority of our natural gas volumes and we do not maintain a credit limit with respect to Anadarko. Consequently, we are subject to the risk of non-payment or late payment by Anadarko for gathering, treating and transmission fees and for proceeds from the sale of natural gas, natural gas liquids and condensate to Anadarko.

We expect our exposure to concentrated risk of non-payment or non-performance to continue for as long as we remain substantially dependent on Anadarko for our revenues. Additionally, we are exposed to credit risk on the note receivable from Anadarko that was issued concurrent with the closing of our initial public offering. We are also party to an omnibus agreement with Anadarko under which Anadarko is required to indemnify us for certain environmental claims, losses arising from rights-of-way claims, failures to obtain required consents or governmental permits and income taxes. Finally, we entered into commodity price swap agreements with Anadarko in order to substantially reduce our exposure to commodity price risk attributable to our percent-of-proceeds contracts for the Hilight system and the Newcastle system and are subject to performance risk thereunder.

If Anadarko becomes unable to perform under the terms of our gathering, processing and transportation agreements, natural gas and NGL purchase agreements, its note payable to us, the omnibus agreement, the services and secondment agreement or the commodity price swap agreements, our ability to make distributions to our unitholders may be adversely impacted.

CONTRACTUAL OBLIGATIONS

Following is a summary of our obligations as of December 31, 2008:

	Office Lease	Asset Retirement Obligations	Note Payable to Anadarko Principal	Note Payable to Anadarko Interest	Total

Office leases: Anadarko leases office space used exclusively by us and charges rental payments to us. The amounts above represent the future minimum rent payments due under the office lease.

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Asset retirement obligations: When assets are acquired or constructed, the initial estimated asset retirement obligation is recognized in an amount equal to the net present value of the settlement obligation, with an associated increase in properties and equipment. Revisions to estimated asset retirement obligations can result from revisions to estimated inflation rates and discount rates, escalating retirement costs and changes in the estimated timing of settlement. For additional information see *Note 10 Asset Retirement Obligations* of the notes to the consolidated financial statements under *Item 8 Financial Statements and Supplementary Data* of this Form 10-K.

Note payable to Anadarko: In connection with the Powder River acquisition, we entered into a five-year, \$175.0 million term loan agreement with Anadarko which calls for interest at a fixed rate of 4.0% for the first two years and a floating rate of interest at three-month LIBOR plus 150 basis points for the final three years.

Also see *Items Affecting the Comparability of Our Financial Results* for a discussion of contractual obligations effective with the initial public offering or Powder River acquisition, including the omnibus agreement, expenses related to operating as a publicly traded partnership, the services and secondment agreement and equity-based compensation plans.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of combined financial statements in accordance with accounting principles generally accepted in the U.S. requires our management to make estimates and assumptions that affect the amounts reported in the combined financial statements and the accompanying notes. Although these estimates are based on management s best available knowledge of current and expected future events, actual results may vary significantly from those estimates. Management considers an understanding of our critical accounting policies and estimates to be essential to gaining a full understanding of our combined financial results. For additional information concerning our accounting policies not discussed below, see the notes to the consolidated financial statements included elsewhere in this annual report on Form 10-K.

Depreciation

Depreciation expense is generally computed using the straight-line method over the estimated useful life of the assets. Determination of depreciation expense requires judgment regarding the estimated useful lives and salvage values of property, plant and equipment. As circumstances warrant, depreciation estimates are reviewed to determine if any changes in the underlying assumptions are necessary. The weighted average life of our long-lived assets is approximately 21 years. If the depreciable lives of our assets were reduced by 10%, we estimate that annual depreciation expense would increase by approximately \$3.5 million, which would result in a corresponding reduction in our operating income.

Impairment of Assets

Each reporting period, management assesses whether facts and circumstances indicate that the carrying amounts of property, plant and equipment may not be recoverable from expected undiscounted cash flows from the use and eventual disposition of an asset. If the carrying amount of the asset is not expected to be recoverable from future undiscounted cash flows, an impairment may be recognized. Any impairment is measured as the excess of the carrying amount of the asset over its estimated fair value.

In assessing long-lived assets for impairment, management evaluates changes in our business and economic conditions and their implications for recoverability of the assets carrying amounts. Since a significant portion of our revenues arises from gathering and transporting natural gas production from Anadarko-operated properties, significant downward revisions in reserve estimates or changes in future development plans by Anadarko, to the extent they affect our operations, may necessitate assessment of the carrying amount of our affected assets for recoverability. Such assessment requires application of judgment regarding the use and ultimate disposition of the asset, long-range revenue and expense estimates, global and regional economic conditions, including commodity prices and drilling activity by our customers, as well as other factors affecting estimated future net cash flows. The measure of impairment to be recognized, if any, depends upon management s estimate of the asset s fair value, which may be determined based on the estimates of future net cash flows or values at which similar assets were transferred in the market in recent transactions, if such data is available. For the periods presented, we believe that no facts were present that indicate the carrying amount of assets may not be recoverable. However, given the degree of judgment about highly uncertain matters involved in assessing our key assets for impairment, it is reasonably possible that such assessments in future periods would have material effects on our financial conditions and results of operations.

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Fair Value

Management estimates fair value in performing impairment tests for long-lived assets and goodwill as well as for the initial measurement of asset retirement obligations. When management is required to measure fair value, and there is not a market observable price for the asset or liability, or a market observable price for a similar asset or liability, management generally utilizes an income or multiples valuation approach. The income approach utilizes management s best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk adjusted discount rate. Such evaluations involve a significant amount of judgment, since the results are based on expected future events or conditions, such as sales prices; estimates of future throughput; capital and operating costs and the timing thereof; economic and regulatory climates and other factors. A multiples approach utilizes management s best assumptions regarding expectations of projected EBITDA and multiple of that EBITDA that a buyer would pay to acquire an asset. Management s estimates of future net cash flows and EBITDA are inherently imprecise because they reflect management s expectation of future conditions that are often outside of management s control. However, assumptions used reflect a market participant s view of long-term prices, costs and other factors, and are consistent with assumptions used in the Partnership s business plans and investment decisions.

OFF-BALANCE SHEET ARRANGEMENTS

We do not have off-balance sheet arrangements other than operating leases. The information pertaining to operating leases required for this item is provided in *Note 13 Commitments and Contingencies* included in the notes to the consolidated financial statements under *Item 8 Financial Statements and Supplementary Data* of this Form 10-K, which information is incorporated by reference.

RECENT ACCOUNTING DEVELOPMENTS

The information required for this item is provided in *Note 2 Summary of Significant Accounting Policies Recently issued accounting standards not yet adopted* included in the notes to the consolidated financial statements under *Item 8 Financial Statements and Supplementary Data* of this Form 10-K, which information is incorporated by reference.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

We bear a limited degree of commodity price risk with respect to certain of our gathering contracts. Specifically, pursuant to certain of our contracts, we retain and sell condensate that is recovered during the gathering of natural gas. As part of this arrangement, we are required to provide a thermally equivalent volume of natural gas or the cash equivalent thereof to the shipper. Thus, our revenues for this portion of our contractual arrangement are based on the price received for the condensate and our costs for this portion of our contractual arrangement depend on the price of natural gas. Condensate historically sells at a price representing a slight discount to the price of NYMEX West Texas Intermediate crude oil.

In addition, certain of our processing services are provided under percent-of-proceeds agreements in which Anadarko is typically responsible for the marketing of the natural gas and NGLs. Under these agreements, we receive a specified percent of the net proceeds from the sale of natural gas and NGLs. To mitigate our exposure to changes in commodity prices on these processing agreements, we entered into commodity price swap agreements with Anadarko with fixed commodity prices that extend through December 31, 2010. For additional information on the commodity price swap agreements, see *Note 6 Transactions with Affiliates* included in the notes to the consolidated financial statements under *Item 8 Financial Statements and Supplementary Data* of this Form 10-K.

We consider our exposure to commodity price risk associated with the above-described arrangements to be minimal given the relatively small amount of our operating income generated by drip condensate sales and the existence of the commodity price swap agreements with Anadarko. For the twelve months ended December 31, 2008, a 10% change in the trading margin between drip condensate and natural gas would have resulted in an approximate $1.1 million, or 2%, change in operating income for the period. A 10% decrease in natural gas and NGLs prices for the twelve months ended December 31, 2008 would have resulted in an approximate $3.0 million, or 4%, decrease in operating income as a result of our percent-of-proceeds contracts; however, this variability attributable to commodity prices has been substantially mitigated through our commodity price swap agreements with Anadarko. For additional information on the commodity price swap agreements, see *Note 6 Transactions with Affiliates* included in the notes to the consolidated financial statements under *Item 8 Financial Statements and Supplementary Data* of this Form 10-K.

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We also bear a limited degree of commodity price risk with respect to settlement of our natural gas imbalances that arise from differences in gas volumes received into our systems and gas volumes delivered by us to customers. Natural gas volumes owed to or by us that are subject to monthly cash settlement are valued according to the terms of the contract as of the balance sheet dates, and generally reflect market index prices. Other natural gas volumes owed to or by us are valued at our weighted average cost of natural gas as of the balance sheet dates and are settled in-kind. Our exposure to the impact of changes in commodity prices on outstanding imbalances depends on the timing of settlement of the imbalances.

Interest Rate Risk

Interest rates during the periods discussed above were low compared to rates over the last 50 years. If interest rates rise, our future financing costs will increase. As of December 31, 2008, we owed $175.0 million to Anadarko under our five-year term loan we entered into in connection with the Powder River acquisition and had $100.0 million of credit available for borrowing under Anadarko s five-year credit facility in addition to $30.0 million available under our two-year working capital facility with Anadarko. Our $175.0 million term loan agreement with Anadarko calls for interest at a fixed rate of 4.0% for the first two years and a floating rate of interest at 3-month LIBOR plus 150 basis points for the final three years. Interest on borrowings under Anadarko s credit facility is calculated based on the election by the borrower of either: (i) a floating rate equal to the federal funds effective rate plus 0.50% or (ii) a periodic fixed rate equal to LIBOR plus an applicable margin. The applicable margin, which was 0.44% at December 31, 2008, is based on Anadarko s senior unsecured long-term debt rating. Borrowings under our working capital facility bear interest at the same rate that would apply to borrowings under the Anadarko credit facility. We may incur additional debt in the future, either through accessing our working capital facility with Anadarko, our $100.0 million borrowing capacity under Anadarko s existing credit facility or other financing sources, including commercial bank borrowings or debt issuances.

Item 8. *Financial Statements and Supplementary Data*

Our consolidated financial statements, together with the report of our independent registered public accounting firm, begin on page F-1 of this report.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None

Item 9A(T). *Disclosure Controls and Procedures*

This annual report does not include management s assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

Item 9B. *Other Information*

Not applicable

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

Management of Western Gas Partners, LP

As a limited partnership, we have no directors or officers. Instead, Western Gas Holdings, LLC, our general partner, manages our operations and activities. Our general partner is not elected by our unitholders and is not subject to re-election in the future. The directors of our general partner oversee our operations. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operations. However, our general partner owes a fiduciary duty to our unitholders, which duty is defined and described in our partnership agreement. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Our general partner, therefore, may cause us to incur indebtedness or other obligations that are nonrecourse to it.

Our general partner s board of directors has nine directors, four of whom are independent as defined under the independence standards established by the New York Stock Exchange, or NYSE, and the Securities Exchange Act of 1934, or the Exchange Act. Our general partner s board of directors has affirmatively determined that Messrs. Milton Carroll, Anthony R. Chase, James R. Crane and David J. Tudor are independent as described in the rules of the NYSE and the Exchange Act. The NYSE does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee.

The executive officers of our general partner manage and conduct our day-to-day operations. The executive officers of our general partner allocate their time between managing our business and affairs and the business and affairs of Anadarko. The executive officers of our general partner may face a conflict regarding the allocation of their time between our business and the other business interests of Anadarko. The officers of our general partner generally do not devote all of their time to our business, although we expect the amount of time that they devote may increase or decrease in future periods as our business continues to develop. The officers of our general partner and other Anadarko employees operate our business and provide us with general and administrative services pursuant to the omnibus agreement and the services and secondment agreement described in *Item 13 Certain Relationships and Related Party Transactions, and Director Independence*. We reimburse Anadarko for allocated expenses of operational personnel who perform services for our benefit, and for certain direct expenses.

Directors and Executive Officers

The following table sets forth information with respect to the directors and executive officers of our general partner as of March 3, 2009. Directors are appointed for a term of one year.

Name	Age	Position with Western Gas Holdings, LLC
Robert G. Gwin	45	President, Chief Executive Officer and Director
Michael C. Pearl	37	Senior Vice President and Chief Financial Officer
Danny J. Rea	50	Senior Vice President, Chief Operating Officer and Director
Amanda M. McMillian	36	Vice President, General Counsel and Corporate Secretary
Jeremy M. Smith	36	Vice President and Treasurer
R.A. Walker	52	Chairman of the Board and Director
Milton Carroll	58	Director
Anthony R. Chase	53	Director
James R. Crane	55	Director
Charles A. Meloy*	49	Director
Robert K. Reeves	51	Director
David J. Tudor	49	Director

* Replaced Karl F. Kurz as a

director
effective
February 25,
2009.

Our directors hold office until their successors shall have been duly elected and qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers.

Robert G. Gwin has served as President and Chief Executive Officer and as a director of our general partner since August 2007. He has served as Senior Vice President, Finance and Chief Financial Officer of Anadarko since March 2009, and prior to that position had served as Senior Vice President of Anadarko since March 2008. He previously served as Vice President, Finance and Treasurer of Anadarko since January 2006. Prior to joining Anadarko, he served as Chief Executive Officer of Community Broadband Ventures, LP from November 2004 to January 2006. Prior to this position, he was with Prosoft Learning Corporation, serving as Chairman and Chief Executive Officer from November 2002 to November 2004 and Chief Financial Officer from 2000 to November 2002. In April 2006, to facilitate its acquisition by another company, Prosoft filed a prepackaged voluntary plan of reorganization. Previously, Mr. Gwin spent 10 years at Prudential Capital Group in merchant banking roles of increasing responsibility, including serving as Managing Director with responsibility for the firm s energy investments worldwide. Mr. Gwin holds a Bachelor of Science degree from the University of Southern California and a Master of Business Administration degree from the Fuqua School of Business at Duke University, and he is a Chartered Financial Analyst.

Michael C. Pearl has served as Senior Vice President and Chief Financial Officer of our general partner since August 2007 and as Director, Accounting of Anadarko since December 2008. Prior to this position, he served as Director, Corporate Tax of Anadarko from August 2006 to December 2008 and corporate tax manager from September 2004 to August 2006. Prior to his tenure at Anadarko, Mr. Pearl joined Ernst & Young LLP in 1995, where he held positions of increasing responsibility, including senior manager, and advised multinational energy companies on structured acquisitions, divestitures, and financings, including advising on partnership taxation and accounting matters. He holds a Bachelor of Business Administration degree and a Master of Science degree in Accounting from Texas A&M University and is a Certified Public Accountant.

Danny J. Rea has served as Senior Vice President and Chief Operating Officer and as a director of our general partner since August 2007 and as Vice President, Midstream of Anadarko since May 2007. Previously, Mr. Rea served as Manager, Midstream Services from May 2004 to May 2007 and Manager, Gas Field Services from August 2000 to May 2007. Mr. Rea joined Anadarko as an engineer in 1981 and has held positions of increasing responsibility over his 27 years with the Company. He holds a Bachelor of Science degree in Petroleum Engineering from Louisiana Tech University, and a Master of Business Administration degree from the University of Houston. He currently serves on the board of directors for the Wyoming Pipeline Authority and is a member of the Gas Processors Association and the Society of Petroleum Engineers.

Amanda M. McMillian has served as Vice President, General Counsel and Corporate Secretary of our general partner since January 2008 and as Senior Counsel of Anadarko since January 2008. She joined Anadarko as Counsel in December 2004. Prior to joining Anadarko, she practiced corporate and securities law at the law firm of Akin Gump Strauss Hauer & Feld LLP. She holds a Bachelor of Arts degree from Southwestern University and Master of Arts and Juris Doctor degrees from Duke University.

Jeremy M. Smith has served as Vice President and Treasurer of our general partner since August 2007 and as Assistant Treasurer, Corporate Finance of Anadarko since July 2006. Prior to joining Anadarko, he served as Assistant Treasurer to Plains Exploration & Production Company from June 2003 to June 2006 and as Assistant Treasurer of 3TEC Energy Corporation from May 2000 until its sale to Plains Exploration & Production Company in June 2003. Mr. Smith holds a Bachelor of Arts degree in Economics from Rice University, a Master of Science degree in Accounting from Texas A&M University and a Master of Business Administration degree from Rice University, and he is a Chartered Financial Analyst.

R.A. Walker has served as non-executive Chairman of the Board and as a director of our general partner since August 2007. He has served as Chief Operating Officer of Anadarko since March 2009, and prior to that position had served as Senior Vice President, Finance and Chief Financial Officer of Anadarko since 2005. Prior to joining Anadarko, he was a Managing Director for the Global Energy Group of UBS Investment Bank from 2003 to 2005 and was President, Chief Financial Officer and a director of 3TEC Energy Corporation from 2000, until its sale to Plains Exploration & Production Company in June 2003. From 1987 to 2000, he worked for Prudential Capital Group in a variety of merchant banking positions, including Senior Managing Director and co-head of Prudential Capital Group at the time of his departure. Mr. Walker has served as a director of Temple-Inland, Inc. since November 2008, and has served on the boards of directors of numerous publicly traded companies, including TEPPCO Partners, L.P. (a NYSE-listed publicly traded partnership) where he served as chairman of the audit committee. Mr. Walker holds Bachelor of Science and Master of Business Administration degrees from the University of Tulsa.

Milton Carroll has served as a director of our general partner and as Chairman of the special committee of the board of directors since April 2008. Mr. Carroll currently serves as Chairman of Houston-based CenterPoint Energy, Inc., where he has been a director since 1992. Mr. Carroll is Chairman and founder of Instrument Products, Inc., an oil-tool manufacturing company in Houston, Texas. He also serves as Chairman of Health Care Services Corporation (a Chicago-based company operating through its Blue Cross and Blue Shield divisions in Illinois, Texas, Oklahoma and New Mexico) and is a director of Halliburton Company. Mr. Carroll holds a Bachelor of Science degree in Industrial Technology from Texas Southern University.

Anthony R. Chase has served as a director of our general partner and as a member of the special and audit committees of the board of directors since April 2008. Since January 2009, Mr. Chase has served as Executive Vice President of Crest Investment Company, a Houston-based private equity firm that develops business opportunities worldwide. Prior to that position, he had most recently served as the Chairman and Chief Executive Officer of ChaseCom, a global customer relationship management and staffing services company until its sale in 2007 to AT&T. Mr. Chase has also been a Professor of Law at the University of Houston since 1991. Mr. Chase currently serves on the board of directors of Cornell Companies. From July 2004 to July 2008, he served as a director of the Federal Reserve Bank of Dallas, and also served as its Deputy Chairman from 2006 until his departure in July 2008. Mr. Chase holds a Bachelor of Arts, Masters of Business Administration and Juris Doctor degrees from Harvard University.

James R. Crane has served as a director of our general partner and as a member of the special and audit committees of the board of directors since April 2008. Mr. Crane is currently Chairman and Chief Executive Officer of Crane Capital Group. He has also served as Chairman of the Board of Crane Worldwide Logistics, a Houston-based single-source provider of global transportation and logistics services, since August 2008. Prior to that time, he served as Founder, Chairman and Chief Executive Officer of EGL, Inc., a NASDAQ-listed global transportation, supply chain management and information services company based in Houston, Texas, from 1984 until its sale in August 2007. Mr. Crane holds a Bachelor of Science degree in Industrial Safety from the University of Central Missouri.

Charles A. Meloy has served as a director of our general partner since February 2009, and as Senior Vice President, Worldwide Operations of Anadarko since December 2006. Before joining Anadarko, he served as Vice President of Exploration and Production at Kerr-McGee Corporation, prior to its acquisition by Anadarko. At Kerr-McGee, Mr. Meloy was Vice President of Gulf of Mexico exploration, production and development from 2004 to 2005, Vice President and Managing Director of North Sea operations from 2002 to 2004, and held several other deepwater Gulf of Mexico management positions beginning in 1999. Earlier in his career, Mr. Meloy held various planning, operations, deepwater and reservoir engineering positions with Oryx Energy Company and its predecessor, Sun Oil Company. He earned a bachelor s degree in chemical engineering from Texas A&M University and is a member of the Society of Petroleum Engineers and Texas Professional Engineers.

Robert K. Reeves has served as a director of our general partner since August 2007 and as Senior Vice President, General Counsel and Chief Administrative Officer of Anadarko since February 2007. He previously served as Senior Vice President, Corporate Affairs & Law and Chief Governance Officer beginning in 2004. He has also served as a director of Key Energy Services, Inc., a publicly traded oil field services company, since October 2007. Prior to joining Anadarko, he served as Executive Vice President, Administration and General Counsel of North Sea New Ventures from 2003 to 2004 and as Executive Vice President, General Counsel and Secretary of Ocean Energy, Inc. and its predecessor companies from 1997 to 2003. Mr. Reeves holds a Bachelor of Science degree in Business Administration and a Juris Doctor degree from Louisiana State University.

David J. Tudor has served as a director of our general partner and as Chairman of the audit committee and a member of the special committee of the board of directors since April 2008. Since 1999, Mr. Tudor has been the President and Chief Executive Officer of ACES Power Marketing, an Indianapolis-based commodity risk management company owned by 16 Generation and Transmission Cooperatives throughout the United States. Prior to joining ACES Power Marketing, Mr. Tudor was the Executive Vice President & Chief Operating Officer of PG&E Energy Trading, where he managed commercial operations in the United States and Canada. He also currently serves as a director of Wabash Valley Power Association s Board Risk Oversight Committee. Mr. Tudor holds a Bachelor of Science degree in Accounting from David Lipscomb University.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner s board of directors and executive officers, and persons who own more than 10 percent of a registered class of our equity securities, to file with the Securities Exchange Commission, or the SEC, and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater than 10 percent unitholders are required by the SEC s regulations to furnish to us and any exchange or other system on which such securities are traded or quoted with copies of all Section 16(a) forms they filed with the SEC.

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that all reporting obligations our general partner s officers, directors and greater than 10 percent unitholders under Section 16(a) were satisfied during the year ended December 31, 2008.

Reimbursement of Expenses of Our General Partner and its Affiliates

Our general partner does not receive any management fee or other compensation for its management of our partnership under the omnibus agreement, as amended, the services and secondment agreement or otherwise. Under the omnibus agreement, our reimbursement to Anadarko for certain general and administrative expenses it allocates to us is capped at $6.65 million annually through December 31, 2009, subject to adjustments to reflect changes in the Consumer Price Index and, with the concurrence of the special committee of our general partner s board of directors, to reflect expansions of our operations through the acquisition or construction of new assets or businesses. Thereafter, our general partner will determine the general and administrative expenses to be reimbursed by us in accordance with our partnership agreement. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses we expect to incur or be allocated to us as a result of being a publicly traded partnership. Please read *Item 13 Certain Relationships and Related Party Transactions, and Director Independence*.

Board Committees

The board of directors of our general partner has two standing committees: the audit committee and the special committee.

Audit Committee

The audit committee is comprised of three independent directors, Messrs. Tudor (chairperson), Chase and Crane, each of whom is able to understand fundamental financial statements and at least one of whom has past experience in accounting or related financial management experience. The board has determined that each member of the audit committee is independent under the NYSE listing standards and the Exchange Act. In making the independence determination, the board considered the requirements of the NYSE and our Code of Business Conduct and Ethics. The audit committee held three meetings in 2008.

Mr. Tudor has been designated by the board of directors of our general partner as the audit committee financial expert meeting the requirements promulgated by the SEC based upon his education and employment experience as more fully detailed in Mr. Tudor s biography set forth above.

The audit committee assists the board of directors in its oversight of the integrity of our combined financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to, among other things, (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm, and (3) establish policies and procedures for the pre-approval of all audit, audit-related, non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the audit committee and to our management, as necessary.

Special Committee

The special committee is comprised of four independent directors, Messrs. Carroll (Chairperson), Chase, Crane and Tudor. The special committee reviews specific matters that the board believes may involve conflicts of interest (including certain transactions with Anadarko). The special committee will determine, as set forth in the partnership agreement, if the resolution of the conflict of interest is fair and reasonable to us. The members of the special committee are not officers or employees of our general partner or directors, officers, or employees of its affiliates, including Anadarko. Our partnership agreement provides that any matters approved by the special committee will be conclusively deemed to be 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 us or our unitholders. The special committee held five meetings in 2008.

Meeting of Non-Management Directors and Communications with Directors

At each quarterly meeting of our general partner s board of directors, all of our independent directors meet in an executive session without management participation or participation by non-independent directors. Mr. Carroll, the chairperson of the special committee, presides over these executive sessions.

The general partner s board of directors welcomes questions or comments about the Partnership and its operations. Unitholders or interested parties may contact the board of directors, including any individual director, at boardofdirectors@westerngas.com or at the following address and fax number; Name of the Director(s), c/o Corporate Secretary, Western Gas Partners, LP, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, (832) 636-6001.

Code of Ethics, Corporate Governance Guidelines and Board Committee Charters

Our general partner has adopted a Code of Ethics For Chief Executive Officer and Senior Financial Officers, or the Code of Ethics, which applies to our general partner s Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller and all other senior financial and accounting officers of our general partner. We will disclose any amendment to, or waiver from, any provision of the Code of Ethics in a current report on Form 8-K. Our general partner has also adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance and a Code of Business Conduct and Ethics applicable to all employees of Anadarko or affiliates of Anadarko who perform services for us and our general partner.

We make available free of charge, within the Investor Relations section of our website at www.westerngas.com/page/ir-governance/, and in print to any unitholder who so requests, the Code of Ethics, the Corporate Governance Guidelines, the Code of Business Conduct and Ethics, our audit committee charter and our special committee charter. Requests for print copies may be directed to investors@westerngas.com or to: Investor Relations, Western Gas Partners LP, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, or telephone (832) 636-6000. We will post on our Internet website all waivers to or amendments of the Code of Ethics, which are required to be disclosed by applicable law and the NYSE s Corporate Governance Listing Standards. The information contained on, or connected to, our Internet website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Item 11. ***Executive Compensation***

Compensation Discussion and Analysis

Overview

We do not directly employ any of the persons responsible for managing our business, and we do not have a compensation committee of the board of directors. Western Gas Holdings, LLC, our general partner, manages our operations and activities, and its board of directors and officers make compensation decisions on our behalf.

Some of the officers of our general partner also serve as officers of Anadarko. The compensation (other than the long-term incentive plan benefits described below) of Anadarko s employees that perform services on our behalf, including our executive officers, is approved by Anadarko s management. Awards under our long-term incentive plan are recommended by Anadarko s management and approved by the board of directors of our general partner. Our reimbursement of Anadarko for the compensation of executive officers is governed by, and subject to the limitations contained in, the omnibus agreement and is based on Anadarko s methodology used for allocating general and administrative expenses to us. Under the omnibus agreement, as amended, our reimbursement of certain general and administrative expenses is capped at $6.65 million annually through December 31, 2009, subject to adjustment to reflect changes in the Consumer Price Index and, with the concurrence of the special committee of our general partner s board of directors, to reflect expansions of our operations through the acquisition or construction of new assets or businesses. Thereafter, our general partner will determine the general and administrative expenses to be reimbursed by us in accordance with our partnership agreement. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses we incur or are allocated to us as a result of being a publicly traded partnership. Please read *Item 13 Certain relationships and related party transactions Omnibus agreement*.

The most highly compensated executive officers of our general partner for 2008 were Robert G. Gwin (the principal executive officer), Michael C. Pearl (the principal financial officer and principal accounting officer), Danny J. Rea (the principal operating officer), Amanda M. McMillian and Jeremy M. Smith (collectively, the named executive officers). Compensation paid or awarded by us in 2008 with respect to the named executive officers reflects only the portion of compensation expense that is allocated to us pursuant to Anadarko s allocation methodology and subject to the terms of the omnibus agreement. Anadarko has the ultimate decision-making authority with respect to the total compensation of the named executive officers and, subject to the terms of the omnibus agreement, the portion of such compensation that is

allocated to us pursuant to Anadarko s allocation methodology. The following discussion relating to compensation paid by Anadarko is based on information provided to us by Anadarko and does not purport to be a complete discussion and analysis of Anadarko s executive compensation philosophy and practices. With the exception of the independent director grants under our long-term incentive plan and awards made under the Western Gas Holdings, LLC Equity Incentive Plan, the elements of compensation discussed below (and Anadarko s decisions with respect to the levels of such compensation), are not subject to approvals by the board of directors of our general partner, including the audit or special committee thereof. Awards under our long-term incentive plan will be made by the board of directors of our general partner.

Anadarko s executive compensation program design, principles and process

Anadarko s executive compensation program is designed to adhere to the following philosophy and design principles: Anadarko s Compensation Committee believes that:

- executive interests should be aligned with stockholder interests;
- executive compensation should be structured to provide appropriate incentive and reasonable reward for the contributions made and performance achieved; and
- a competitive compensation package must be provided to attract and retain experienced, talented executives to ensure Anadarko s success.

In support of this philosophy, Anadarko s executive compensation programs are designed to adhere to the following principles:

- a majority of total executive compensation should be in the form of equity-based compensation;
- a meaningful portion of total executive compensation should be tied directly to the achievement of goals and objectives related to Anadarko s targeted financial and operating performance;
- a significant component of performance-based compensation should be tied to long-term relative performance measures that emphasize an increase in stockholder value over time;
- performance-based compensation opportunities should not encourage excessive risk taking that may compromise Anadarko s value or its stockholders;
- executives should maintain significant levels of equity ownership;
- to encourage retention, a substantial portion of compensation should be forfeitable by the executive upon voluntary termination;
- total compensation opportunities should be reflective of each executive officer s role, skills, experience level and individual contribution to the organization; and
- our executives should be motivated to contribute as team members to Anadarko s overall success, as opposed to merely achieving specific individual objectives.

Anadarko establishes compensation levels for each executive officer, which are generally targeted between the 50th and 75th percentiles of Anadarko s industry peer group. In setting compensation levels of each executive officer, Anadarko considers individual experience, individual performance, internal equity, development and/or succession status, and other individual or organizational circumstances. In the case of our named executive officers, Anadarko takes into account the additional duties, as applicable, our executive officers assume in connection with their roles as officers of our general partner.

With respect to compensation objectives and decisions regarding the named executive officers for 2008, Anadarko s management reviewed market data for determining relevant compensation levels and compensation program elements.

In addition, Anadarko s management reviewed and, in certain cases, participated in, various relevant compensation surveys and consulted with compensation consultants with respect to determining 2008 compensation for our named executive officers. All compensation determinations are discretionary and, as noted above, subject to Anadarko s decision-making authority.

Elements of compensation

The primary elements of Anadarko s compensation program are a combination of annual cash and long-term equity-based compensation. For 2008, the principal elements of compensation for the named executive officers are as follows:

- base salary;
- annual cash incentives;
- equity-based compensation, which includes equity-based compensation under Anadarko s 1999 Stock Incentive Plan, Anadarko s 2008 Omnibus Incentive Compensation Plan, or the Omnibus Plan, the Western Gas Partners, LP 2008 Long-Term Incentive Plan, and the Western Gas Holdings, LLC Equity Incentive Plan; and
- Anadarko s other benefits, including welfare and retirement benefits, severance benefits and change of control benefits, plus other benefits on the same basis as other eligible Anadarko employees.

Base Salary. Anadarko s management establishes base salaries to provide a fixed level of income for our named executive officers for their level of responsibility (which may or may not be related to our business), their relative expertise and experience, and in some cases their potential for advancement. As discussed above, a portion of the base salaries of our named executive officers is to be allocated to us based on Anadarko s methodology used for allocating general and administrative expenses, subject to the limitations in the omnibus agreement.

Annual Cash Incentives (Bonuses). Anadarko s management awarded annual cash awards to our named executive officers in 2009 under the 2008 Anadarko s annual incentive program, or AIP, which is part of Anadarko s Omnibus Plan. Annual cash incentive awards are used by Anadarko to motivate and reward executives for the achievement of Anadarko objectives aligned with value creation and/or recognize individual contributions to Anadarko s performance. The annual incentive program puts a portion of an executive s compensation at risk by linking potential annual compensation to Anadarko s achievement of specific performance metrics during the year related to operational, financial and safety measures internal to Anadarko. The overall funding for Anadarko s annual incentive program is capped at 200% of target. Executives may receive up to 200% of their individual bonus target if Anadarko significantly exceeds the specified performance metrics and, conversely, no bonus is paid if Anadarko does not achieve a minimum threshold level of performance. For those named executive officers who are also officers of Anadarko, actual bonus awards were determined by the compensation and benefits committee, or compensation committee, of Anadarko s board of directors according to Anadarko s, and each officer s contribution toward, achievement against the established performance metrics. The bonus targets are intended to provide a designated level of compensation opportunity when Anadarko and the officers achieve the specified performance metrics as approved by Anadarko s compensation committee.

The portion of any annual cash awards allocable to us is based on Anadarko s methodology used for allocating general and administrative expenses, subject to the limitations established in the omnibus agreement. Anadarko s general policy is to pay these awards during the first quarter of each calendar year for the prior year s performance.

Long-Term Incentive Awards Under Anadarko s 2008 Omnibus Incentive Compensation Plan. Anadarko periodically makes equity-based awards under its Omnibus Plan, to align the interests of its executive officers with those of Anadarko shareholders by emphasizing the long-term growth in Anadarko s value. For 2008, the annual equity awards consisted of a combination of (1) stock options, (2) time-based restricted stock and restricted stock units, and/or (3) performance unit awards. This award structure is intended to provide a combination of equity-based vehicles that is performance-based in absolute and relative terms, while also encouraging retention.

Our Long-Term Incentive Plan. Our general partner has adopted the Western Gas Partners, LP 2008 Long-Term Incentive Plan for the employees and directors of our general partner and the employees of its affiliates, including Anadarko, who perform services for us. The long-term incentive plan provides for the grant of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and substitute awards. For a more detailed description of this plan, please read *Long-term incentive plan*. Any equity-based awards to our executive officers and the directors of our general partner are intended to align their long-term interests with those of our unitholders. Currently, only the non-management directors of our general partner hold grants awarded under this plan.

Our General Partner s Amended and Restated Equity Incentive Plan. Our general partner has adopted the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan for the executive officers of our general partner. The awards of unit appreciation rights, unit value rights and distribution equivalent rights made under this plan are designed to provide incentive compensation to encourage superior performance. For a description of this plan, please read *Amended and Restated Western Gas Holdings, LLC Equity Incentive Plan*.

Other Benefits. In addition to the compensation discussed above, Anadarko also provides other benefits to the named executive officers who are also executive officers of Anadarko, including:

- retirement benefits to match competitive practices in Anadarko s industry, including the Anadarko Employee Savings Plan, Anadarko s Savings Restoration Plan, and the Anadarko Retirement Plan and Retirement Restoration Plan;
- severance benefits under the Anadarko Severance Plan or the Anadarko Officer Severance Plan, as applicable;
- certain change of control benefits under key employee change of control contracts;
- director and officer indemnification agreements;
- a limited number of perquisites, including financial counseling, tax preparation and estate planning, an executive physical program, management disability insurance, and personal excess liability insurance; and
- benefits including medical, dental, vision, flexible spending accounts, paid time off, life insurance and disability coverage, which are also provided to all other eligible U.S.-based Anadarko employees.

For a more detailed summary of Anadarko s executive compensation program and the benefits provided thereunder, please read *Compensation Discussion and Analysis* in Anadarko s proxy statement for its annual meeting of stockholders, which is expected to be filed with the SEC no later than April 9, 2009.

Role of executive officers in executive compensation

Anadarko s compensation committee determines the compensation (other than the long-term incentive plan benefits described above) payable to our named executive officers who are also senior executive officers of Anadarko and Anadarko s management determines the compensation for each of our other named executive officers. The board of directors of our general partner determines compensation for the independent, non-management directors of our general partner s board of directors, as well as any grants made under our long-term incentive plan and its equity incentive plan.

Compensation mix

We believe that the mix of base salary, cash awards, awards under Anadarko s stock incentive plan, our long-term incentive plan and our general partner s equity incentive plan, and other compensation fit Anadarko s and our overall compensation objectives. We believe this mix of compensation provides competitive compensation opportunities to align and drive employee performance in support of Anadarko s business strategies, as well as our own, and to attract, motivate and retain high-quality talent with the skills and competencies required by Anadarko and us.

WESTERN GAS PARTNERS, LP 2008 LONG-TERM INCENTIVE PLAN

General

In April 2008, our general partner adopted the Western Gas Partners, LP 2008 Long-Term Incentive Plan, which we refer to as the LTIP, for employees and directors of our general partner and its affiliates, including Anadarko, who perform services for us. The summary of the LTIP contained herein does not purport to be complete and is qualified in its entirety by reference to the LTIP. The LTIP provides for the grant of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and substitute awards. Subject to adjustment for certain events, an aggregate of 2,250,000 common units may be delivered pursuant to awards under the LTIP. Units that are cancelled, forfeited or are withheld to satisfy our general partner s tax withholding obligations or payment of an award s exercise price are available for delivery pursuant to other awards. The LTIP is administered by our general partner s board of directors. The LTIP has been designed to promote the interests of the partnership and its unitholders by strengthening its ability to attract, retain and motivate qualified individuals to serve as directors and employees.

Unit awards

Our general partner s board of directors may grant unit awards to eligible individuals under the LTIP. A unit award is an award of common units that are fully vested upon grant and are not subject to forfeiture. No unit awards were granted during 2008.

Restricted units and phantom units

A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the recipient holds a common unit that is not subject to forfeiture. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of our general partner s board of directors, cash equal to the fair market value of a common unit. Our general partner s board of directors may make grants of restricted and phantom units under the LTIP that contain such terms, consistent with the LTIP, as the board may determine are appropriate, including the period over which restricted or phantom units will vest. The board may, in its discretion, base vesting on the grantee s completion of a period of service or upon the achievement of specified financial objectives or other criteria. In addition, the restricted and phantom units will vest automatically upon a change of control of our general partner (as defined in the LTIP) or as otherwise described in the award agreement. Our general partner s board of directors approved phantom unit grants to each of Messrs. Carroll, Chase, Crane and Tudor in connection with their election to the board. The phantom units granted to each of these directors in 2008 have a value of $125,000. These phantom units vest on the first anniversary of the date of grant and have tandem distribution equivalent rights.

If a grantee s employment or membership on the board of directors terminates for any reason, the grantee s restricted and phantom units will be automatically forfeited unless and to the extent that the award agreement or the board provides otherwise.

Distributions made by us with respect to awards of restricted units may, in the board s discretion, be subject to the same vesting requirements as the restricted units. The board, in its discretion, may also grant tandem distribution equivalent rights with respect to phantom units.

Unit options and unit appreciation rights

The LTIP also permits the grant of options covering common units and unit appreciation rights. Unit options represent the right to purchase a number of common units at a specified exercise price. Unit appreciation rights represent the right to receive the appreciation in the value of a number of common units over a specified exercise price, either in cash or in common units as determined by the board. Unit options and unit appreciation rights may be granted to such eligible individuals and with such terms as the board may determine, consistent with the LTIP; however, a unit option or unit appreciation right must have an exercise price greater than or equal to the fair market value of a common unit on the date of grant. No unit options or unit appreciation rights were granted during 2008.

Distribution equivalent rights

Distribution equivalent rights are rights to receive all or a portion of the distributions otherwise payable on units during a specified time. Distribution equivalent rights may be granted alone or in combination with another award.

Source of common units; cost

Common units to be delivered with respect to awards may be newly-issued units, common units acquired by our general partner in the open market, common units already owned by our general partner or us, 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 such common units. With respect to unit options, our general partner is entitled to reimbursement from us for the difference between the cost it incurs in acquiring these common units and the proceeds it receives from an optionee at the time of exercise. Thus, we bear the cost of the unit options. If we issue new common units with respect to these awards, the total number of common units outstanding will increase, and our general partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash, our general partner is entitled to reimbursement by us for the amount of the cash settlement.

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Amendment or termination of long-term incentive plan

Our general partner s board of directors, in its discretion, may terminate the LTIP at any time with respect to the common units for which a grant has not previously been made. The LTIP will automatically terminate on the earlier of the 10th anniversary of the date it was initially adopted by our general partner or when common units are no longer available for delivery pursuant to awards under the LTIP. Our general partner s board of directors will also have the right to alter or amend the LTIP or any part of it from time to time or to amend any outstanding award made under the LTIP; provided, however, that no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the affected participant, and/or result in taxation to the participant under Section 409A of the Internal Revenue Code of 1986, as amended, unless otherwise determined by the general partner s board of directors.

WESTERN GAS HOLDINGS, LLC AMENDED AND RESTATED EQUITY INCENTIVE PLAN

General

Our general partner has adopted the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan, which we refer to as the Incentive Plan, for the executive officers of our general partner. The summary of the Incentive Plan and related award grants contained herein does not purport to be complete and is qualified in its entirety by reference to the Incentive Plan. The Incentive Plan provides for the grant of unit appreciation rights, unit value rights and distribution equivalent rights. Subject to adjustment for certain events, an aggregate of 100,000 unit appreciation rights, 100,000 unit value rights and 100,000 distribution equivalent rights may be delivered pursuant to awards under the Incentive Plan. Unit appreciation rights, unit value rights and distribution equivalent rights that are forfeited, cancelled, or otherwise terminated or expired without payment are available for grant pursuant to other awards made under the Incentive Plan. The Incentive Plan is administered by our general partner s board of directors. The LTIP has been designed to provide to key executives of the general partner incentive compensation to encourage superior performance of the partnership and the general partner. The costs of these awards are allocated within and subject to the reimbursement provisions of the omnibus agreement.

Unit appreciation rights

Our general partner s board of directors may grant unit appreciation rights to eligible individuals under the Incentive Plan. A unit appreciation right is the economic equivalent of a stock appreciation right so it does not include a participant s pro rata share of the value of our general partner as of the grant date. Our general partner s board of directors has the authority to determine the executives to whom unit appreciation rights may be granted, the number of unit appreciation rights to be granted to each participant, the period over and the conditions, if any, under which the unit appreciation rights may become vested or forfeited, and such other terms and conditions as the board may establish with respect to such awards.

The number of unit appreciation rights outstanding will be adjusted by our general partner s board of directors upon certain changes in capitalization to prevent the valuation dilution or enlargement of potential benefits intended to be provided with respect to awards granted under the Incentive Plan; provided, however, that no change in any outstanding award made as a result of a change in capitalization may materially impair the rights of the participant without the consent of the affected participant.

Unless otherwise provided in the award agreement, termination of a participant s employment with Anadarko shall cause all of such participant s unvested awards under the Incentive Plan to be forfeited upon termination. However, the general partner s board of directors may, in its discretion, waive in whole or in part such forfeiture.

Vesting of unit appreciation rights

Our general partner s board of directors has the authority to determine the restrictions and vesting provisions for any unit appreciation rights. The initial grants of unit appreciation rights under the Incentive Plan provide for vesting (x) in one-third increments over a three-year period commencing on the first anniversary of the grant date or (y) immediately upon the occurrence of any of the following events, if they occur earlier, including: (1) a change of control of our general partner or Anadarko; (2) the closing of an initial public offering of our general partner; (3) termination of employment with our general partner and its affiliates (including Anadarko) due to involuntary termination (with or without cause); (4) death; (5) disability as defined under Section 409A of the Internal Revenue Code of 1986, as amended; or (6) an unforeseeable emergency as defined in the Incentive Plan. Upon the occurrence of a vesting event, each participant will receive a lump-sum cash payment (less any applicable withholding taxes) for each unit appreciation right that is exercised prior to the earlier of the 90^{th} day after a participant s voluntary termination and the 10th anniversary of the grant date. The unit appreciation rights may not be sold or transferred except to the general partner, Anadarko or any of their affiliates.

Unit value rights

Our general partner s board of directors may grant unit value rights to eligible individuals under the Incentive Plan. A unit value right imparts to a participant his or her pro rata share of the value of the general partner at the time of grant. Our general partner s board of directors has the authority to determine the executives to whom unit value rights may be granted, the number of unit value rights to be granted to each participant, the period over and the conditions, if any, under which the unit value rights may become vested or forfeited, and such other terms and conditions as the board may establish with respect to such awards.

The number of unit value rights outstanding will be adjusted by our general partner s board of directors upon certain changes in capitalization to prevent the valuation dilution or enlargement of potential benefits intended to be provided with respect to awards granted under the Incentive Plan; provided, however, that no change in any outstanding award made as a result of a change in capitalization may materially impair the rights of the participant without the consent of the affected participant.

Unless otherwise provided in the award agreement, termination of a participant s employment with Anadarko shall cause all of such participant s unvested awards under the Incentive Plan to be forfeited upon termination. However, the general partner s board of directors may, in its discretion, waive in whole or in part such forfeiture.

Vesting of unit value rights

Our general partner s board of directors has the authority to determine the restrictions and vesting provisions for any unit value rights. The initial grants of unit value rights provide for vesting (x) in one-third increments over a three-year period commencing on the first anniversary of the grant date or (y) immediately upon the occurrence of any of the following events, if they occur earlier, including: (1) a change of control of our general partner or Anadarko; (2) the closing of an initial public offering of our general partner; (3) termination of employment with our general partner and its affiliates (including Anadarko) due to involuntary termination (with or without cause); (4) death; (5) disability as defined under Section 409A of the Internal Revenue Code of 1986, as amended; or (6) an unforeseeable emergency as defined in the Incentive Plan. Upon the occurrence of a vesting event, each participant will receive a lump-sum cash payment (less any applicable withholding taxes) for each unit value right. The unit value rights may not be sold or transferred except to the general partner, Anadarko or any of their affiliates.

Distribution equivalent rights

Grants of unit appreciation rights and unit value rights also include an equal number of distribution equivalent rights, which entitle the holder to receive with respect to each unit appreciation right and unit value right awarded an amount in cash or incentive units equal in value to the distributions made by our general partner to its members during the period an award is outstanding. These distribution equivalent rights are subject to the same vesting requirements as the incentive units with which such distribution equivalent rights are associated.

Vesting of distribution equivalent rights

Our general partner s board of directors has the authority to determine the restrictions and vesting provisions for any distribution equivalent rights. The initial grants of distribution equivalent rights provide for vesting immediately upon the occurrence of any of the following events, including: (1) a change of control of our general partner or Anadarko; (2) the closing of an initial public offering of our general partner; (3) termination of employment with our general partner and its affiliates (including Anadarko) due to involuntary termination (with or without cause); (4) death; (5) disability as defined under Section 409A of the Internal Revenue Code of 1986, as amended; (6) the date three days in advance of the 10th anniversary of the grant date; or (7) an unforeseeable emergency as defined in the Incentive Plan. Upon the occurrence of a vesting event, each participant will receive a lump-sum cash payment (less any applicable withholding taxes) for each distribution equivalent right. The distribution equivalent rights may not be sold or transferred except to our general partner, Anadarko or any of their affiliates.

Amendment or termination of Incentive Plan

Our general partner s board of directors, in its discretion, may amend or terminate the Incentive Plan at any time with respect to the unit appreciation rights, unit value rights and distribution equivalent rights, including increasing the number of unit

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appreciation rights, unit value rights and distribution equivalent rights available for awards under the Incentive Plan, without the consent of the participants. The board may also waive any conditions, rights or terms under any award under this plan, provided that no change in any award under the plan will materially reduce the benefit to a participant in the plan without such participant s consent. The Incentive Plan will terminate on the date termination is approved by our general partner s board of directors or when all unit appreciation rights, unit value rights and distribution equivalent rights available under the Incentive Plan have been paid to participants.

EXECUTIVE COMPENSATION

We do not directly employ any of the persons responsible for managing or operating our business and we have no compensation committee. Instead, we are managed by our general partner, Western Gas Holdings, LLC, the executive officers of which are employees of Anadarko. Our reimbursement for the compensation of executive officers is governed by the omnibus agreement and the services and secondment agreement described in *Item 13 Certain Relationships and Related Party Transactions, and Director Independence Agreements with Anadarko Services and secondment agreement*.

Summary Compensation Table For 2008

The following table summarizes the compensation amounts expensed by us for our general partner s Chief Executive Officer, Chief Financial Officer and our three highest paid executive officers other than our CEO and CFO for the period of May 14, 2008 through December 31, 2008, which represents the time period following our initial public offering.

Summary Compensation Table

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Stock Awards ($)(2)	Option Awards ($)(3)	Non-Equity Incentive Plan Compensation ($)(4)	All Other Compensation ($)(5)	Total ($)
Robert G. Gwin President and Chief Executive Officer	2008	107,392	0	371,769	208,411	163,977	28,137	879,686
Michael C. Pearl Senior Vice President and Chief Financial Officer	2008	55,286	0	109,486	24,272	53,787	14,485	257,316
Danny J. Rea Senior Vice President and Chief Operating Officer	2008	65,699	0	158,583	37,952	72,459	17,213	351,906
Amanda M. McMillian Vice President, General Counsel and Corporate Secretary	2008	48,011	0	76,874	0	32,049	12,579	169,513
Jeremy M. Smith Vice President and Treasurer	2008	46,083	0	88,537	0	26,754	12,074	173,448

(1) The amounts in this column reflect the base salary compensation allocated to us by Anadarko for the period of May 14, 2008 through December 31, 2008.

(2) The amounts in this column reflect the compensation cost allocated to us by Anadarko for the period of May 14, 2008 through December 31, 2008, in accordance with SFAS No. 123(R) for non-option stock awards granted pursuant to the Western Gas Holdings, LLC Equity Incentive Plan, 2008 Omnibus Incentive Compensation Plan and the 1999 Stock Incentive Plan and includes amounts from awards granted in and prior to 2008. The awards

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granted by Western Gas Holdings, LLC were valued under SFAS No. 123(R) by multiplying the number of units awarded by the current per unit valuation on the date of grant of $50.00, assuming no forfeitures. The value per unit was based on the estimated fair value of the general partner using a hybrid discounted cash flow and multiples valuation approach. For a discussion of valuation assumptions for the awards under the 2008 Omnibus Incentive Plan and the 1999 Stock Incentive Plan, see *Note 12 Stock-Based Compensation* of the Notes to Consolidated Financial Statements included in Anadarko s annual report under Item 8 of the Form 10-K for the year ended

December 31, 2008. For information regarding the non-option stock awards granted to the named executives in 2008, please see the Grants of Plan-Based Awards Table.

(3) The amounts in this column reflect the compensation cost allocated to us by Anadarko for the period of May 14, 2008 through December 31, 2008, in accordance with SFAS No. 123(R) for option awards granted pursuant to the Western Gas Holdings, LLC Equity Incentive Plan, 2008 Omnibus Incentive Compensation Plan and the 1999 Stock Incentive Plan and may include amounts from option awards granted in and prior to 2008. See note (2) above for valuation assumptions.

(4)

The amounts in this column reflect the annual incentive compensation allocated to us for the period of May 14, 2008 through December 31, 2008. These amounts represent payments under the Anadarko annual incentive program, which were earned in 2008 and paid in early 2009.

(5) The amounts in this column reflect the compensation expenses related to Anadarko s retirement and savings plans that were allocated to us for the period of May 14, 2008 through December 31, 2008. These allocated expenses are detailed in the table below:

Name	Retirement Plan Expense	Savings Plan Expense
Robert G. Gwin	$ 19,760	$ 8,377
Michael C. Pearl	$ 10,173	$ 4,312
Danny J. Rea	$ 12,089	$ 5,124
Amanda M. McMillian	$ 8,834	$ 3,745
Jeremy M. Smith	$ 8,479	$ 3,595

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Grants of Plan-Based Awards in 2008

The following table sets forth information concerning annual incentive awards, stock options, unit appreciation rights, unit value rights, restricted stock shares, restricted stock units and performance units granted during 2008 to each of the named executive officers:

Name and Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1) Threshold ($)	Target ($)	Maximum ($)	Estimated Future Payouts Under Equity Incentive Plan Awards(2) Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units (#)(3)	All Other Option Awards: Number of Securities Underlying Options (#)(4)	Exercise or Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Stock and Option Awards ($)(5)
Robert G. Gwin										
		94,240	188,479							
3/12/2008								22,300	64.69	196,881
4/2/2008(6)							20,000			483,333
12/20/2008(7)								20,000	50.00	
12/20/2008(7)							20,000			
11/4/2008								78,600	35.18	489,132
11/4/2008(8)							12,800			225,152
11/4/2008				5,211	19,300	38,600				432,417
Michael C. Pearl										
		26,959	53,918							
3/13/2008								5,000	65.99	44,508
3/13/2008							3,000			90,857
4/2/2008(6)							10,000			241,667
12/20/2008(7)								10,000	50.00	
12/20/2008(7)							10,000			
Danny J. Rea										
		43,604	87,208							
4/2/2008(6)							10,000			241,667
12/20/2008(7)								10,000	50.00	
12/20/2008(7)							10,000			
11/4/2008								19,100	35.18	118,861
11/4/2008(8)							7,800			137,202
11/4/2008				1,080	4,000	8,000				89,620
Amanda M. McMillian										
		15,723	31,446							

3/13/2008			4,927			149,217
4/2/2008(6)			5,000			120,833
12/20/2008(7)				5,000	50.00	
12/20/2008(7)			5,000			
Jeremy M. Smith						
	14,957	29,914				
3/13/2008			5,227			158,303
4/2/2008(6)			5,000			120,833
12/20/2008(7)				5,000	50.00	
12/20/2008(7)			5,000			

(1) Reflects the estimated future cash payouts allocable to us under Anadarko s annual incentive program. The estimated amounts are calculated based on the applicable annual bonus target and base salary earnings for each named executive officer in effect for the 2008 measurement period. If threshold levels of performance are not met, then the payout can be zero. The expense allocated to us for the actual bonus payouts under the annual incentive program for 2008 are reflected in the *Non-Equity Incentive Plan Compensation* column of the Summary Compensation Table. For additional discussion of Anadarko s annual incentive program please see section *Compensation Discussion and Analysis Elements of*

Total Compensation Annual Cash Incentives (Bonuses) of Anadarko s proxy statement for its annual meeting of stockholders which is expected to be filed no later than April 9, 2009.

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(2) Reflects the estimated future payout under Anadarko s performance unit awards. Executives may earn from 0% to 200% of the targeted award based on Anadarko s relative TSR performance over a specified performance period. Fifty percent of this award is tied to a two-year performance period and the remaining fifty percent is tied to a three-year performance period. If earned, the awards are to be paid in cash. The threshold value represents the minimum payment (other than zero) that may be earned. For additional discussion of Anadarko s performance unit awards please see section *Compensation Discussion and Analysis Elements of Total Compensation Annual Cash Incentives (Bonuses)* of Anadarko s proxy statement for its annual meeting of stockholders which is expected to be filed no later than April 9, 2009.

(3) Reflects the number of unit value rights, restricted stock shares

and restricted stock units awarded in 2008. These awards vest equally over three years, beginning with the first anniversary of the grant date. Executive officers receive distribution equivalent rights on the unit value rights, dividends on the restricted stock shares and dividends equivalents on the restricted stock units.

(4) Reflects the number of stock options and unit appreciation rights each named executive officer was awarded in 2008. These awards vest equally over three years, beginning with the first anniversary of the date of grant. The stock options have a term of seven years and the unit appreciation rights have a term of ten years.

(5) The amounts included in the *Grant Date Fair Value of Stock and Option Awards* column represent the expected allocation to us of the grant date fair value of the awards made to named executives in 2008 computed in accordance with SFAS No. 123(R). The value ultimately realized by the

executive upon the actual vesting of the award(s) or the exercise of the unit appreciation right(s) and stock option(s) may or may not be equal to the SFAS No. 123(R) determined value. The awards granted by Western Gas Holdings, LLC were valued under SFAS No. 123(R) by multiplying the number of units awarded by the current per unit valuation on the date of grant of $50.00, assuming no forfeitures. The value per unit was based on the estimated fair value of the general partner using a hybrid discounted cash flow and multiples valuation approach. For a discussion of valuation assumptions for the awards under the 2008 Omnibus Incentive Plan and the 1999 Stock Incentive Plan, see *Note 12 Stock-Based Compensation* of the Notes to Consolidated Financial Statements included in Anadarko s annual report under *Item 8* of the Form 10-K for the year ended December 31, 2008.

(6) The April 2, 2008 equity incentive unit awards were granted

under the Western Gas Holdings, LLC Equity Incentive Plan. These awards were modified on December 20, 2008 in order to comply with the requirements of Section 409A of the Internal Revenue Code of 1986, as amended. The restructured awards as a result of the modification are described below in footnote 7.

(7) The awards shown for December 20, 2008 reflect a modification to the April 2, 2008 awards. This modification was made in order for the original awards to comply with the requirements of Section 409A of the Internal Revenue Code of 1986, as amended. The modification effectively split the April 2nd incentive unit awards granted into an equal number of unit appreciation rights and unit value rights. The unit appreciation rights vest equally over three years, beginning with the original award grant date and have a term of ten years. The unit value rights vest equally over three years, beginning with the original award grant

date and have a maximum per unit value of $50.00. In addition to these units, participants are eligible to receive an equal number of distribution equivalent rights which become payable upon certain events. Pursuant to the SEC rules, the incremental value (if any) of the modification must be shown in the grant date fair value column. The incremental fair value computed as of the modification date in accordance with SFAS 123(R) was zero. These awards are discussed further on beginning on page 83 of the Compensation Discussion and Analysis.

(8) For accounting purposes, these awards have a November 4, 2008 grant date which is based on the date Anadarko s Compensation and Benefits Committee approved the awards and the date the terms of the awards were communicated to participants. The effective date for participants is December 1, 2008. The awards vest equally over three

years, beginning with
the first anniversary
of the participant
grant date.

Outstanding Equity Awards at Fiscal Year-End 2008

The following table reflects all outstanding equity awards as of December 31, 2008 for each of the named executives, including both Anadarko and Western Gas Holdings, LLC awards and does not take into account that under our omnibus agreement with Anadarko we are only allocated a portion of the SFAS No. 123(R) expense related to these awards. The market values shown are based on Anadarko s closing stock price on December 31, 2008 of $38.55, unless otherwise noted.

	Option Awards(1)				Stock Awards			
					Restricted Stock Shares/Units and Unit Value Rights(2)		Equity Incentive Plan Awards Performance Units(3)	
	Number of Securities Underlying Unexercised Options							
Name	Exercisable (#)	Unexercisable (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Market Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Robert G. Gwin	13,500	13,500	50.6900	1/16/2013	8,500	327,675	2,325	89,629
	12,734	6,366	48.6900	12/4/2013	1,966	75,789	7,600	292,980
	13,667	27,333	40.5100	1/10/2014	4,800	185,040	19,300	744,015
	7,234	14,466	59.8700	11/6/2014	12,800	493,440		
		22,300	64.6900	3/12/2015	20,000(5)	1,000,000(6)		
		78,600	35.1800	11/4/2015				
		20,000(4)	50.0000	4/2/2018				
Michael C. Pearl	958	958	48.9000	12/1/2013	541	20,856		
	2,500	5,000	51.8900	7/2/2014	3,333	128,487		
		5,000	65.9900	3/13/2015	3,000	115,650		
		10,000(4)	50.0000	4/2/2018	10,000(5)	500,000(6)		
Danny J. Rea	5,000		21.4525	10/30/2010	1,083	41,750	7,400	285,270
	5,000		33.4000	12/2/2011	2,333	89,937	4,000	154,200
	5,000		43.5550	11/15/2012	7,800	300,690		
	3,834	1,916	48.9000	12/1/2013	10,000(5)	500,000(6)		

	3,534	7,066	59.8700	11/6/2014		
		19,100	35.1800	11/4/2015		
		10,000(4)	50.0000	4/2/2018		
Amanda M. McMillian		5,000(4)	50.0000	4/2/2018	470	18,119
					1,200	46,260
					4,927	189,936
					5,000(5)	250,000(6)
Jeremy M. Smith		5,000(4)	50.0000	4/2/2018	833	32,112
					833	32,112
					1,000	38,550
					5,227	201,501
					5,000(5)	250,000(6)

(1) The table below shows the vesting dates for the respective unexercisable stock options and unit appreciation rights listed in the above Outstanding Equity Awards Table:

Vesting Date	Robert G. Gwin	Michael C. Pearl	Danny J. Rea	Amanda M. McMillian	Jeremy M. Smith
1/10/2009	13,667				
3/12/2009	7,434				
3/13/2009		1,667			
4/2/2009	6,667	3,334	3,334	1,667	1,667
7/2/2009		2,500			
11/4/2009	26,200		6,367		
11/6/2009	7,233		3,533		
12/1/2009		958	1,916		
12/4/2009	6,366				
1/10/2010	13,666				
1/16/2010	13,500				
3/12/2010	7,433				
3/13/2010		1,667			
4/2/2010	6,667	3,333	3,333	1,667	1,667
7/2/2010		2,500			
11/4/2010	26,200		6,367		
11/6/2010	7,233		3,533		
3/12/2011	7,433				
3/13/2011		1,666			
4/2/2011	6,666	3,333	3,333	1,666	1,666
11/4/2011	26,200		6,366		

(2) The table below shows the vesting dates for the respective restricted stock shares, restricted stock units and unit value rights

listed in the above Outstanding Equity Awards Table:

Vesting Date	Robert G. Gwin	Michael C. Pearl	Danny J. Rea	Amanda M. McMillian	Jeremy M. Smith
1/16/2009	4,250				
3/13/2009		1,000		1,643	1,743
4/2/2009	6,667	3,334	3,334	1,667	1,667
7/2/2009		1,667		600	500
8/1/2009					833
12/1/2009	4,267	541	3,683	470	833
12/3/2009	2,400		1,167		
12/4/2009	1,966				
1/16/2010	4,250				
3/13/2010		1,000		1,642	1,742
4/2/2010	6,667	3,333	3,333	1,667	1,667
7/2/2010		1,666		600	500
12/1/2010	4,267		2,600		
12/3/2010	2,400		1,166		
3/13/2011		1,000		1,642	1,742
4/2/2011	6,666	3,333	3,333	1,666	1,666
12/1/2011	4,266		2,600		

(3) The table below shows the performance periods for the respective performance units listed in the above Outstanding Equity Awards Table:

Performance Period	Robert G. Gwin	Danny J. Rea
1/1/2008 to 12/31/2009	6,125	3,700
1/1/2008 to 12/31/2010	3,800	3,700
1/1/2009 to 12/31/2010	9,650	2,000
1/1/2009 to 12/31/2011	9,650	2,000

(4) This award represents a grant of unit appreciation rights under the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan.

(5) This award represents a grant of unit value rights under the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan.

(6) The market value for this award is calculated based on the per unit value effective on December 31, 2008 of $50.00.

Option Exercises and Stock Vested in 2008

The following table reflects all Anadarko option awards exercised in 2008 and Anadarko stock awards that vested in 2008 and does not take into account that under our omnibus agreement with Anadarko we were only allocated a portion of the SFAS No. 123(R) expense related to these awards. Please refer to the Summary Compensation Table on page 85 for a summary of the total expense allocated to us in 2008 for both option and stock awards.

	Option Awards		**Stock Awards**	
Name	**Number of Shares Acquired on Exercise (#)**	**Value Realized on Exercise ($)(1)**	**Number of Shares Acquired on Vesting (#)(2)**	**Value Realized on Vesting ($)(1)**
Robert G. Gwin			8,617	404,709
Michael C. Pearl	959	27,138	3,041	175,574
Danny J. Rea	6,000	309,432	4,216	196,984

Amanda M. McMillian	1,802	94,310
Jeremy M. Smith	2,166	115,266

(1) The Value Realized reflects the taxable value to the named executive officer as of the date of the option exercise or vesting of restricted stock. The actual value ultimately realized by the named executive officer may be more or less than the Value Realized calculated in the above table depending on the timing in which the named executive officer held or sold the stock associated with the exercise or vesting occurrence.

(2) Shares acquired on vesting include restricted stock shares or units whose restrictions lapsed during 2008.

Pension Benefits for 2008

Anadarko maintains both funded tax-qualified defined benefit pension plans and unfunded nonqualified pension benefit plans. The nonqualified pension benefit plans are designed to provide for supplementary pension benefits due to limitations imposed by the Internal Revenue Code that restrict the amount of benefits payable under tax-qualified plans. Our named executive officers are eligible to participate in these plans. As part of the omnibus agreement a portion of the expense related to these plans is allocated to us by Anadarko. The allocated expense for each named executive officer is included in the *All Other Compensation* column of the Summary Compensation Table on page 85. For additional discussion on Anadarko s pension benefits, please see section *Compensation Discussion and Analysis Elements of Total Compensation Retirement Benefits* of Anadarko s proxy statement for its annual meeting of stockholders which is expected to be filed no later than April 9, 2009.

Nonqualified Deferred Compensation for 2008

Anadarko maintains a Deferred Compensation Plan and a Savings Restoration Plan for certain employees, including our named executive officers. The Deferred Compensation Plan allows certain employees to voluntarily defer receipt of up to 75% of their salary and/or up to 100% of their annual incentive bonus payments. The Savings Restoration Plan accrues a benefit substantially equal to the amount that, in the absence of certain Internal Revenue Code limitations, would have been allocated to their account as matching contributions under the Anadarko s 401(k) Plan. Pursuant to the terms of the omnibus agreement, a portion of the expense related to these plans is allocated to us by Anadarko. The allocated expense for each named executive officer is included in the *All Other Compensation* column of the Summary Compensation Table on page 85. For additional discussion on Anadarko s pension benefits please see section *Compensation Discussion and Analysis Elements of Total Compensation Retirement Benefits* of Anadarko s proxy statement for its annual meeting of stockholders which is expected to be filed no later than April 9, 2009.

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Potential Payments Upon Termination or Change of Control

In the event of termination of employment with Western Gas Holdings, LLC by reason of: (A) a Change of Control of either Western Gas Holdings, LLC or Anadarko; (B) the closing of an initial public offering of Western Gas Holdings, LLC; (C) the involuntary termination of employment with Western Gas Holdings, LLC or its affiliates (with or without cause); (D) death; (E) disability, as defined under Section 409A of the Internal Revenue Code of 1986, as amended; or (F) an unforeseeable emergency, and assuming that the employee remains employed by Anadarko, the only payment triggered is the acceleration of awards under the Western Gas Holdings, LLC Equity Incentive Plan. The award values under this Plan as of December 31, 2008 are as follows:

Name	**Accelerated Incentive Plan Awards(1)**
Robert G. Gwin	$1,000,000
Michael C. Pearl	$ 500,000
Danny J. Rea	$ 500,000
Amanda M. McMillian	$ 250,000
Jeremy M. Smith	$ 250,000

(1) Values are based on the December 31, 2008 per unit value of $50.00.

We have not entered into any employment agreements with our named executive officers, nor do we manage any severance plans. However, our named executive officers are eligible for certain benefits provided by Anadarko. Currently, we are not allocated any expense for these agreements or plans, but for disclosure purposes we are presenting the full value of the potential payments provided by Anadarko in the event of termination or change of control of Anadarko. Values exclude those benefits generally provided to all salaried employees. For additional discussion related to these termination scenarios, please see section *Compensation Discussion and Analysis Elements of Total Executive Compensation Severance Benefits* of Anadarko s proxy statement for its annual meeting of stockholders which is expected to be filed no later than April 9, 2009.

The following tables reflect potential payments to our named executive officers under existing contracts, agreements, plans or arrangements, whether written or unwritten, with Anadarko, for various scenarios involving a change of control of Anadarko or termination of employment from Anadarko for each named executive officer, assuming a December 31, 2008 termination date, and, where applicable, using the closing price of Anadarko s common stock of $38.55 (as reported on the NYSE as of December 31, 2008). As of December 31, 2008, none of our executive officers were eligible for retirement; accordingly, no table is included for this event.

Involuntary For Cause or Voluntary Termination

	Mr. Gwin	**Mr. Pearl**	**Mr. Rea**	**Ms. McMillian**	**Mr. Smith**
Supplemental Pension Benefits(1)	$ 81,533	$17,258	$465,196	$3,501	$3,404
Nonqualified Deferred Compensation(2)	$ 35,355	$ 8,829	$102,923	$2,513	$2,783
Total	**$116,888**	**$26,087**	**$568,119**	**$6,014**	**$6,187**

(1) Reflects the lump-sum present value of

vested benefits related to Anadarko s supplemental pension benefits.

(2) Reflects the combined vested balances in Anadarko s nonqualified Savings Restoration Plan and Deferred Compensation Plan.

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Involuntary Not For Cause Termination

	Mr. Gwin	Mr. Pearl	Mr. Rea	Ms. McMillian	Mr. Smith
Cash Severance(1)	$1,377,500	$	$ 689,000	$	$
Pro-rata Bonus for 2008(2)	$ 338,154	$	$ 156,462	$	$
Accelerated Anadarko Equity Compensation(3)	$2,473,450	$264,993	$ 936,214	$254,314	$304,275
Accelerated Western Equity Compensation(4)	$1,000,000	$500,000	$ 500,000	$250,000	$250,000
Supplemental Pension Benefits(5)	$ 169,032	$ 17,258	$1,162,329	$ 3,501	$ 3,404
Nonqualified Deferred Compensation(6)	$ 35,355	$ 8,829	$ 102,923	$ 2,513	$ 2,783
Health and Welfare Benefits(7)	$ 41,737	$	$ 156,723	$	$
Financial Counseling(8)	$ 24,898	$	$ 24,898	$	$
Total	**$5,460,126**	**$791,080**	**$3,728,549**	**$510,328**	**$560,462**

(1) Messrs. Gwin s and Rea s values assume two times base salary plus one times target bonus. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(2) Messrs. Gwin s and Rea s values assume a pro-rata bonus based on target bonus percentages effective for the 2008 AIP and eligible earnings as of

December 31, 2008. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(3) Reflects the in-the-money value of unvested stock options, the target value of unvested performance units, and the value of unvested restricted stock shares and restricted stock units, granted under Anadarko equity plans, all as of December 31, 2008.

(4) Reflects the in-the-money value of unvested unit appreciation rights and the value of unvested unit value rights, granted under the Western Gas Holdings, LLC Equity Incentive Plan. Values are based on the December 31,

2008 per unit value of $50.00.

(5) Messrs. Gwin s and Rea s values include a special retirement benefit enhancement that is equivalent to the additional supplemental pension benefits that would have accrued assuming they were eligible for subsidized early retirement benefits. All other named executive officers values reflect their vested balance in Anadarko s Retirement Restoration Plan. Values exclude vested amounts payable under the qualified plans available to all employees.

(6) Reflects the combined vested balances in Anadarko s nonqualified Savings Restoration Plan and Deferred Compensation Plan.

(7) Messrs. Gwin s and Rea s values

represent 24 months of health and welfare benefit coverage. These amounts are present values determined in accordance with SFAS No. 106, *Employer s Accounting for Postretirement Benefits other than Pensions*. Mr. Rea s value also includes the present value of a retiree death benefit in Anadarko s Management Life Insurance Plan, or MLIP. The MLIP provides for a retiree death benefit equal to one times final base salary. This retiree death benefit is only applicable to participants who were employed by Anadarko on June 30, 2003. Therefore, this benefit is only applicable to Mr. Rea. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(8) Messrs. Gwin s and Rea s values assume financial counseling services continue for two years after termination. No values have been disclosed for the other named executive officers as they are not eligible for this benefit.

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Change of Control: Involuntary Termination or Voluntary For Good Reason

	Mr. Gwin	Mr. Pearl	Mr. Rea	Ms. McMillian	Mr. Smith
Cash Severance(1)	$2,250,243	$	$1,440,157	$	$
Pro-rata Bonus for 2008(2)	$ 300,946	$	$ 231,606	$	$
Accelerated Anadarko Equity Compensation(3)	$2,473,450	$264,993	$ 936,214	$254,314	$304,275
Accelerated Western Equity Compensation(4)	$1,000,000	$500,000	$ 500,000	$250,000	$250,000
Supplemental Pension Benefits(5)	$ 629,294	$ 17,258	$1,438,627	$ 3,501	$ 3,404
Nonqualified Deferred Compensation(6)	$ 175,026	$ 8,829	$ 192,312	$ 2,513	$ 2,783
Health and Welfare Benefits(7)	$ 62,977	$	$ 183,636	$	$
Outplacement Assistance(8)	$ 30,000	$	$ 30,000	$	$
Financial Counseling(9)	$ 38,099	$	$ 38,099	$	$
Excise Tax and Gross-up(10)	$1,956,051	$	$1,494,610	$	$
Total	**$8,916,086**	**$791,080**	**$6,485,261**	**$510,328**	**$560,462**

(1) Messrs. Gwin s and Rea s values assume 2.9 times the sum of base salary plus the highest bonus paid in the past three years. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(2) Messrs. Gwin s and Rea s values assume the full-year equivalent of the highest annual bonus the officer

received over the past three years. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(3) Reflects the in-the-money value of unvested stock options, the target value of unvested performance units, and the value of unvested restricted stock shares and restricted stock units, granted under Anadarko equity plans, all as of December 31, 2008.

(4) Reflects the in-the-money value of unvested unit appreciation rights and the value of unvested unit value rights, granted under the Western Gas Holdings, LLC Equity Incentive Plan. Values are based on the

December 31, 2008 per unit value of $50.00.

(5) Messrs. Gwin s and Rea s values include a special retirement benefit enhancement that is equivalent to the additional supplemental pension benefits that would have accrued assuming the named executive officers were eligible for subsidized early retirement benefits and include special pension credits provided through change of control agreements. All other named executive officers values reflect their vested balance in Anadarko s Retirement Restoration Plan. Values exclude vested amounts payable under the qualified plans available to all employees.

(6) Messrs. Gwin s and Rea s values include their

combined balances in Anadarko s nonqualified Savings Restoration Plan and Deferred Compensation Plan plus an additional three years of employer contributions into the Savings Restoration Plan based on their current contribution rate to the LTIP. All other named executive officers values reflect their combined balances in Anadarko s nonqualified Savings Restoration Plan and Deferred Compensation Plan.

(7) Messrs. Gwin s and Rea s values represent 36 months of health and welfare benefit coverage. All amounts are present values determined in accordance with SFAS No. 106, *Employer s Accounting for Postretirement Benefits other than Pensions*. Mr. Rea s value

also includes the present value of a retiree death benefit in the MLIP. The MLIP provides for a retiree death benefit equal to one times final base salary. This retiree death benefit is only applicable to participants who were employed by Anadarko on June 30, 2003. Therefore, this benefit is only applicable to Mr. Rea. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(8) Messrs. Gwin s and Rea s values represent the outplacement assistance benefits provided under their change of control agreements. No values have been disclosed for the other named executive officers as they

receive the same benefits as generally provided to all salaried employees.

(9) Messrs. Gwin s and Rea s values assume financial counseling services continue for three years after termination. No values have been disclosed for the other named executive officers as they are not eligible for this benefit.

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(10) Values estimate the total payment required to make each executive whole for the 20% excise tax imposed by Section 280G of the Internal Revenue Code. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

Disability

	Mr. Gwin	Mr. Pearl	Mr. Rea	Ms. McMillian	Mr. Smith
Cash Severance	$	$	$	$	$
Pro-rata Bonus for 2008(1)	$	$	$	$	$
Accelerated Anadarko Equity Compensation(2)	$2,473,450	$264,993	$ 936,214	$254,314	$304,275
Accelerated Western Equity Compensation(3)	$1,000,000	$500,000	$ 500,000	$250,000	$250,000
Supplemental Pension Benefits(4)	$ 81,533	$ 17,258	$ 465,196	$ 3,501	$ 3,404
Nonqualified Deferred Compensation(5)	$ 35,355	$ 8,829	$ 102,923	$ 2,513	$ 2,783
Health and Welfare Benefits(6)	$ 283,017	$	$ 155,505	$	$
Total	**$3,873,355**	**$791,080**	**$2,159,838**	**$510,328**	**$560,462**

(1) There are no special arrangements related to the payment of a pro-rata bonus in the event of disability.

Payments are paid pursuant to the standards established under Anadarko s annual incentive program for all salaried employees.

(2) Reflects the in-the-money value of unvested stock options, the target value of unvested performance units, and the value of unvested restricted stock shares and restricted stock units, granted under Anadarko equity plans, all as of December 31, 2008.

(3) Reflects the in-the-money value of unvested unit appreciation rights and the value of unvested unit value rights, granted under the Western Gas Holdings, LLC Equity Incentive Plan. Values are based on the December 31, 2008 per unit value of $50.00.

(4) Reflects the lump sum present value of vested benefits related to Anadarko s supplemental pension benefits.

(5) Reflects the combined vested balances in Anadarko s nonqualified Savings Restoration Plan and Deferred Compensation Plan.

(6) Messrs. Gwin s and Rea s values reflect the continuation of additional death benefit coverage provided to officers of Anadarko until age 65. All amounts are present values determined in accordance with SFAS No. 106, *Employer s Accounting for Postretirement Benefits other than Pensions*. No values have been disclosed for the other named executive officers as they are not eligible for this benefit.

Death

	Mr. Gwin	Mr. Pearl	Mr. Rea	Ms. McMillian	Mr. Smith
Cash Severance	$	$	$	$	$
Pro-rata Bonus for 2008(1)	$	$	$	$	$
Accelerated Anadarko Equity Compensation(2)	$2,473,450	$264,993	$ 936,214	$254,314	$304,275
Accelerated Western Equity Compensation(3)	$1,000,000	$500,000	$ 500,000	$250,000	$250,000
Supplemental Pension Benefits(4)	$ 81,533	$ 17,258	$ 465,196	$ 3,501	$ 3,404
Nonqualified Deferred Compensation(5)	$ 35,355	$ 8,829	$ 102,923	$ 2,513	$ 2,783
Life Insurance Proceeds(6)	$1,494,886	$	$ 833,989	$	$
Total	**$5,085,224**	**$791,080**	**$2,838,322**	**$510,328**	**$560,462**

(1) There are no special arrangements related to the payment of a pro-rata bonus in the event of death. Payments are paid pursuant to the standards established under Anadarko s annual incentive program for all salaried employees.

(2) Reflects the in-the-money value of unvested stock options, the target value of unvested performance units, and the value of unvested restricted stock shares and restricted stock units, granted under Anadarko equity plans, all

as of
December 31,
2008.

(3) Reflects the in-the-money value of unvested unit appreciation rights and the value of unvested unit value rights, granted under the Western Gas Holdings, LLC Equity Incentive Plan. Values are based on the December 31, 2008 per unit value of $50.00.

(4) Includes the lump sum present value of vested benefits related to Anadarko s supplemental pension benefits.

(5) Includes the combined vested balances in Anadarko s nonqualified Savings Restoration Plan and Deferred Compensation Plan.

(6) Messrs. Gwin s and Rea s values include amounts payable under additional death benefits provided to officers and other key

employees of Anadarko. These liabilities are not insured, but are self-funded by Anadarko. Proceeds are not exempt from federal taxes; values shown include an additional tax gross-up amount to equate benefits with nontaxable life insurance proceeds. Values exclude death benefit proceeds from programs available to all employees. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

Director Compensation

Officers or employees of Anadarko who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. Non-employee directors of Anadarko receive compensation for their board service and for attending meetings of the board of directors of our general partner and committees of the board pursuant to the director compensation plan approved by the board of directors in April 2008. Such compensation consists of:

- an annual retainer of $40,000 for each board member;
- an annual retainer of $2,000 for each member of the audit committee ($15,000 for the committee chair);
- an annual retainer of $2,000 for each member of the special committee ($15,000 for the committee chair);
- a fee of $2,000 for each board meeting attended;

a fee of $2,000 for each committee meeting attended; and

annual grants of phantom units with a value of $70,000, all of which vest 100% on the first anniversary of the date of grant (with vesting to be accelerated upon a change of control of our general partner or Anadarko).

In addition, each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees. Each director is fully indemnified by us, pursuant to individual indemnification agreements and our partnership agreement, for actions associated with being a director to the fullest extent permitted under Delaware law. On May 14, 2008, the non-employee directors received an initial grant of phantom units with a value of $125,000.

The following table sets forth information concerning total director compensation earned during the 2008 fiscal year by each non-employee director:

Name	**Fees Earned or Paid in Cash ($)**	**Stock Awards ($)(1)**	**Option Awards ($)**	**Non-Equity Incentive Plan Compensation ($)**	**Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)**	**All Other Compensa-tion ($)**	**Total ($)**
Milton Carroll	79,000	80,825					159,825
Anthony R. Chase	72,000	80,825					152,825
James R. Crane	70,000	80,825					150,825
David J. Tudor	87,000	80,825					167,825

(1) The amounts included in the *Stock Awards* column represent the compensation cost recognized by the Partnership in 2008 related to non-option awards to directors, computed in accordance with SFAS No. 123(R). For a discussion of valuation assumptions, see *Note 6 Transactions with Affiliates Equity-based compensation Long-term incentive plan* of the Notes to Consolidated Financial Statements included in our annual report under Item 8 of the Form 10-K for the

year ended December 31, 2008. As of December 31, 2008, each of the non-employee directors had 7,576 outstanding phantom units.

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The following table contains the grant date fair value of phantom unit awards made to each non-employee director during 2008.

Directors	Grant Date	Phantom Units (#)	Grant Date Fair Value of Stock and Option Awards ($)(1)
Milton Carroll	May 14	7,576	125,004
Anthony R. Chase	May 14	7,576	125,004
James R. Crane	May 14	7,576	125,004
David J. Tudor	May 14	7,576	125,004

(1) The amounts included in the *Grant Date Fair Value of Stock and Option Awards* column represent the grant date fair value of the awards made to non-employee directors in 2008 computed in accordance with SFAS No. 123(R). The value ultimately realized by a director upon the actual vesting of the award(s) may or may not be equal to the SFAS No. 123(R) determined value. The awards granted by Western Gas Holdings, LLC were valued under SFAS No. 123(R) by

multiplying the number of units awarded by the current per unit valuation on the date of grant of $50.00, assuming no forfeitures. The value per unit was based on the estimated fair value of the general partner using a hybrid discounted cash flow and multiples valuation approach.

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. Messrs. Walker, Gwin, Meloy, Rea and Reeves, who are directors of our general partner, are also executive officers of Anadarko. However, all compensation decisions with respect to each of these persons are made by Anadarko 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 Anadarko.

Compensation Committee Report

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 Western Gas Holdings, LLC:

Robert G. Gwin
Charles A. Meloy
Danny J. Rea
Robert K. Reeves
R.A. Walker
Milton Carroll
Anthony R. Chase
James R. Crane
David J. Tudor

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

The following tables set forth the beneficial ownership of our units as of February 27, 2009 held by:

each member of the board of directors of our general partner;

each named executive officer of our general partner;

all directors and officers of our general partner as a group; and

each person or group of persons known by us to be a beneficial owner of 5% or more of the then outstanding units.

Name and address of beneficial owner[(1)]	**Common units beneficially owned[(2)]**	**Percentage of common units beneficially owned**	**Subordinated units beneficially owned**	**Percentage of subordinated units beneficially owned**	**Percentage of total common and subordinated units beneficially owned**
Anadarko Petroleum Corporation[(2)]	8,282,322	28.5%	26,536,306	100.0%	62.6%
Western Gas Resources, Inc.[(2)]	8,282,322	28.5%	26,536,306	100.0%	62.6%
WGR Holdings, LLC[(2)]	8,282,322	28.5%	26,536,306	100.0%	62.6%
Robert G. Gwin	10,000	*			*
Michael C. Pearl					
Danny J. Rea	7,500	*			*
Amanda M. McMillian					
Jeremy M. Smith	3,800	*			*
R.A. Walker	6,000	*			*
Milton Carroll[(3)]	4,800	*			*
Anthony R. Chase[(3)]	15,200	*			*
James R. Crane[(3)]	350,582	*			*
Charles A. Meloy	3,000	*			*
Robert K. Reeves	9,000	*			*
David J. Tudor[(3)]	1,500	*			*
All directors and executive officers as a group (12 persons)[(3)]	411,382	*			*

* Less than 1%

(1) Unless otherwise indicated, the address for all beneficial owners in this

table is 1201 Lake Robbins Drive, The Woodlands, Texas 77380.

(2) Anadarko Petroleum Corporation is the ultimate parent company of WGR Holdings, LLC and Western Gas Resources, Inc. and may, therefore, be deemed to beneficially own the units held by WGR Holdings, LLC and Western Gas Resources, Inc.

(3) Does not include 7,576 phantom units that were granted to each of Messrs. Carroll, Chase, Crane and Tudor under the Western Gas Partners, LP 2008 Long-Term Incentive Plan. These phantom units vest 100% on the first anniversary of the date of the grant. Each vested phantom unit entitles the holder to receive a common unit or, in the discretion of our

general partner s board of directors, cash equal to the fair market value of a common unit. Holders of phantom units are entitled to distribution equivalents on a current basis. Holders of phantom units have no voting rights until such time as the phantom units become vested and common units are issued to such holders.

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The following table sets forth, as of March 3, 2009, the number of shares of common stock of Anadarko owned by each of the named executive officers and directors of our general partner and all directors and executive officers of our general partner as a group.

Name and address of beneficial owner[(1)]	Shares of common stock owned directly or indirectly[(2)]	Shares underlying options exercisable within 60 days[(2)]	Total shares of common stock beneficially owned[(2)]	Percentage of total shares of common stock beneficially owned[(2)]
Robert G. Gwin[(3)(4)]	21,305	68,236	89,541	*
Michael C. Pearl[(4)]	8,533	5,125	13,658	*
Danny J. Rea[(3)(4)]	8,901	22,368	31,269	*
Amanda M. McMillian[(4)]	8,524	0	8,524	*
Jeremy M. Smith[(4)]	11,438	0	11,438	*
R.A. Walker[(3)(4)]	61,340	126,802	188,142	*
Milton Carroll	0	0	0	*
Anthony R. Chase	0	0	0	*
James R. Crane	0	0	0	*
Charles A. Meloy[(3)(4)]	27,259	37,001	64,260	*
Robert K. Reeves[(3)(4)]	44,150	269,368	313,518	*
David J. Tudor	0	0	0	*
All directors and executive officers as a group (12 persons)[(3)(4)]	191,450	528,900	720,350	*

* Less than 1%

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 1201 Lake Robbins Drive, The Woodlands, Texas 77380.

(2) As of December 31, 2008, there were 459.9 million shares of Anadarko Petroleum Corporation

common stock issued and outstanding.

(3) Does not include unvested restricted stock units of Anadarko Petroleum Corporation held by the following directors and executive officers in the amounts indicated: Robert G. Gwin 47,500, Danny J. Rea 10,133; R.A. Walker 43,533; Charles A. Meloy 20,666; Robert K. Reeves 30,000; and a total of 151,832 unvested restricted stock units are held by the directors and executive officers as a group. Restricted stock units typically vest equally over three years beginning on the first anniversary of the date of grant, and upon vesting are payable in Anadarko common stock, subject to applicable tax withholding. Holders of restricted stock units receive dividend equivalents on

the units, but do not have voting rights. Generally, a holder will forfeit any unvested restricted units if he or she terminates voluntarily or is terminated for cause prior to the vesting date. Holders of restricted stock units have the ability to defer such awards.

(4) Includes unvested shares of restricted common stock of Anadarko Petroleum Corporation held by the following directors and executive officers in the amounts indicated: Robert G. Gwin 6,216; Michael C. Pearl 6,874; Danny J. Rea 1,083; Amanda M. McMillian 6,597; Jeremy M. Smith 7,893; R.A. Walker 16,266; Charles A. Meloy 3,933; Robert K. Reeves 3,633; and a total of 52,495 unvested shares of restricted common stock are held by the directors and executive officers

as a group. Restricted stock awards typically vest equally over three years beginning on the first anniversary of the date of grant. Holders of restricted stock receive dividends on the shares and also have voting rights. Generally, a holder of restricted stock will forfeit any unvested restricted shares if he or she terminates voluntarily or is terminated for cause prior to the vesting date.

The following table sets forth owners of 5% or greater of our units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Units	Kayne Anderson Capital Advisors, L.P. 1800 Avenue of the Stars Second Floor Los Angeles, CA 90067	2,225,203 (1)	8.39%
Common Units	Neuberger Berman Inc. 605 Third Avenue New York, NY 10158	1,965,244 (2)	7.406%

(1) Based upon its Schedule 13G filed February 12, 2009 with the SEC with respect to Company securities held as of December 31, 2008, Kayne

Anderson Capital Advisors, L.P. has shared voting power as to 2,225,203 shares of common units and shared dispositive power as to 2,225,203 shares of common units, and Richard A. Kayne has shared

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voting power as to 2,225,203 shares of common units and shared dispositive power as to 2,225,203 shares of common units.

(2) Based upon its Schedule 13G filed February 13, 2009 with the SEC with respect to Company securities held as of December 31, 2008, Neuberger Berman Inc. has sole voting power as to 1,756,934 shares of common units, and shared dispositive power as to 1,965,244 shares of common units, and Neuberger Berman, LLC has sole voting power as to 1,756,934 shares of common units and shared dispositive power as to 1,965,244 shares of common units.

Securities Authorized for Issuance Under Equity Compensation Plan

The following table sets forth information with respect to the securities that may be issued under the Western Gas Partners, LP 2008 Long-Term Incentive Plan, or LTIP, as of December 31, 2008. For more information regarding the LTIP, which did not require approval by our unitholders, please read *Note 6 Transactions with Affiliates* included in the notes to the consolidated financial statements under *Item 8 Financial Statements and Supplementary Data* of this Form 10-K and *Item 11 Executive Compensation Long-Term Incentive Plan*.

Plan category	**(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights**	**(b) Weighted-average exercise price of outstanding options, warrants and rights**	**(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))**
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders(1)	30,304	(2)	2,219,696
Total	30,304		2,219,696

(1) The board of directors of our general partner adopted the LTIP in connection with the initial public offering of our common units.

(2) Phantom units constitute the only rights outstanding under the LTIP. Each phantom unit that may be settled in common units entitles the holder to receive, upon vesting, one common unit with respect to each phantom unit,

without payment
of any cash.
Accordingly,
there is no
reportable
weighted-average
exercise price.

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

As of February 27, 2009, our general partner and its affiliates owned 8,282,322 common units and 26,536,306 subordinated units representing an aggregate 61.3% limited partner interest in us. In addition, as of February 27, 2009, our general partner owned 1,135,296 general partner units, representing a 2% general partner interest in us, as well as incentive distribution rights.

Distributions and Payments to Our General Partner and its Affiliates

The following table summarizes the distributions and payments made by us to our general partner and its affiliates in connection with our formation and to be made to us by our general partner and its affiliates in connection with our ongoing operation and liquidation. These distributions and payments were determined, before our initial public offering, by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Formation stage

The consideration received by Anadarko and its subsidiaries for the contribution of the assets and liabilities to us	5,725,431 common units; 26,536,306 subordinated units; 1,083,115 general partner units, and our incentive distribution rights.

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Operational stage

Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions of 98.0% to our unitholders pro rata, including Anadarko as the indirect holder of an aggregate 8,282,322 common units and 26,536,306 subordinated units, and 2.0% to our general partner, assuming it makes any capital contributions necessary to maintain its 2.0% interest in us. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target distribution level. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $1.4 million on their general partner units and $41.8 million on their common and subordinated units.
Payments to our general partner and its affiliates	Our general partner and its affiliates are entitled to reimbursement for all expenses incurred on our behalf, including salaries and employee benefit costs for employees who provide services to us, and all other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business. The partnership agreement provides that our general partner determines in good faith the amount of such expenses that are allocable to us.
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, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Anadarko

We and other parties entered into various agreements with Anadarko in connection with our initial public offering in May 2008 and our asset acquisition in December 2008. These agreements address the acquisition of assets and the assumption of liabilities by us and our subsidiaries. These agreements were not the result of arm s-length negotiations and, as such, they or underlying transactions may not be based on terms as favorable as those that could have been obtained from unaffiliated third parties.

Omnibus agreement

In connection with our initial public offering, we entered into an omnibus agreement with Anadarko and our general partner that addresses the following matters:

- Anadarko s obligation to indemnify us for certain liabilities and our obligation to indemnify Anadarko for certain liabilities;

- our obligation to reimburse Anadarko for all expenses incurred or payments made on our behalf in conjunction with Anadarko s provision of general and administrative services to us, including salary and benefits of Anadarko personnel, our public company expenses, general and administrative expenses and salaries and benefits of our executive management who are employees of Anadarko;

- our obligation to reimburse Anadarko for all insurance coverage expenses it incurs or payments it makes with respect to our assets; and our obligation to reimburse Anadarko for our allocable portion of commitment fees

(0.11% of our committed and available borrowing capacity) that Anadarko incurs under its $1.3 billion credit facility.

The table below reflects the categories of expenses for which the Partnership was obligated to reimburse Anadarko pursuant to the omnibus agreement for the year ended December 31, 2008:

		Period from May 14, 2008 to December 31, 2008
		(in millions)
Reimbursement of general and administrative expenses	$	3.4
Reimbursement of public company expenses	$	3.1
Reimbursement of expenses related to Powder River acquisition	$	1.5
Reimbursement of commitment fees	$	0.1

Our general partner and its affiliates also received payments from us pursuant to the contractual arrangements described below under the caption *Contracts with affiliates.*

Any or all of the provisions of the omnibus agreement are terminable by Anadarko at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The omnibus agreement will also generally terminate in the event of a change of control of us or our general partner.

Administrative services and reimbursement

Under the omnibus agreement, we reimburse Anadarko for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit with respect to our initial assets and for subsequent acquisitions. The omnibus agreement further provides that we reimburse Anadarko for all expenses it incurs or payments it makes with respect to our assets.

Pursuant to these arrangements, Anadarko performs centralized corporate functions for us, such as legal, accounting, treasury, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, tax, marketing and midstream administration. We reimburse Anadarko for all of the expenses it incurs or payments it makes on our behalf, including salaries and benefits of Anadarko personnel, our public company expenses, our general and administrative expenses and salaries and benefits of our executive management who are also employees of Anadarko.

Under the omnibus agreement, our reimbursement to Anadarko for certain general and administrative expenses it allocates to us was capped at $6.0 million annually. This cap was subsequently modified on December 19, 2008 due to the Powder River acquisition from Anadarko and is currently $6.65 million annually through December 31, 2009. The cap is subject to adjustment to reflect changes in the Consumer Price Index and, with the concurrence of the special committee of our general partner s board of directors, to reflect expansions of our operations through the acquisition or construction of new assets or businesses. Thereafter, our general partner will determine the general and administrative expenses to be allocated to us in accordance with our partnership agreement. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses that we incur or are allocated to us as a result of being a publicly traded entity.

Indemnification

Under the omnibus agreement, Anadarko has indemnified us until May 14, 2011 against certain potential environmental claims, losses and expenses associated with the operation of our initial assets, which occurred prior to May 14, 2008 or relate to any investigation, claim or proceeding under environmental laws relating to such assets and pending as of May 14, 2008. Anadarko will have no indemnification obligation with respect to environmental claims on our initial assets made as a result of additions to or modifications of environmental laws that are promulgated after May 14, 2008.

Additionally, Anadarko will indemnify us for losses attributable to the following with respect to our initial assets:

(1) our failure, as of May 14, 2008, to have valid easements, fee title or leasehold interests in and to the lands on which our assets are located, to the extent such failure renders us unable to use or operate our assets in

substantially the same manner in which they were used and operated immediately prior to the closing of our initial public offering;

(2) our failure, as of May 14, 2008, to have any consent or governmental permit necessary to allow (i) the transfer of assets from Anadarko to us at May 14, 2008 or (ii) us to use or operate our assets in substantially the same manner in which they were used and operated immediately prior to May 14, 2008;

(3) all income tax liabilities

(i) attributable to the pre-closing operations of our assets,

(ii) arising from or relating to the formation transactions, or

(iii) arising under Treasury Regulation Section 1.1502-6 and any similar provision from state, local or foreign applicable law, by contract, as successor or transferee or otherwise, provided that such income tax is attributable to having been a member of any consolidated, combined or unitary group prior to the closing of our initial public offering;

(4) all liabilities, other than covered environmental laws and other than liabilities incurred in the ordinary course of business conducted in compliance with the applicable laws, that arise prior to May 14, 2008; and

(5) all liabilities attributable to any assets or entities retained by Anadarko.

Anadarko s liability for indemnification is unlimited in amount. Anadarko will not have any obligation to indemnify us, unless a claim for indemnification specifying in reasonable detail the basis for such claim is furnished to us in good faith (a) with respect to a claim under clause (1) or (2) above, prior to the third anniversary date of the closing of our initial public offering or (b) with respect to a claim under clause (3) or (5) above, prior to the first day after expiration of the statute of limitations period applicable to such claim. In no event shall Anadarko be obligated to indemnify us for any losses or income taxes to the extent we have made reservations for any such losses or income taxes in our combined financial statements as of December 31, 2007, or to the extent we recover any such losses or income taxes under available insurance coverage or from contractual rights against any third party.

Under the omnibus agreement, we have agreed to indemnify Anadarko for all claims, losses and expenses attributable to operations of our initial assets on or after May 14, 2008, to the extent that such losses are not subject to Anadarko s indemnification obligations.

Indemnification Agreements

In connection with our initial public offering, our general partner entered into indemnification agreements with each of its officers and directors (each, an Indemnitee). Each indemnification agreement provides that our general partner will indemnify and hold harmless each Indemnitee against all expense, liability and loss (including attorney s fees, judgments, fines or penalties and amounts to be paid in settlement) actually and reasonably incurred or suffered by the Indemnitee in connection with serving in their capacity as officers and directors of our general partner (or of any subsidiary of our general partner) or in any capacity at the request of our general partner or its board of directors to the fullest extent permitted by applicable law, including Section 18-108 of the Delaware Limited Liability Company Act in effect on the date of the agreement or as such laws may be amended to provide more advantageous rights to the Indemnitee. The indemnification agreements also provide that our general partner must advance payment of certain expenses to the Indemnitee, including fees of counsel, in advance of final disposition of any proceeding subject to receipt of an undertaking from the Indemnitee to return such advance if it is ultimately determined that the Indemnitee is not entitled to indemnification.

Through December 31, 2008, there have been no payments or claims to Anadarko related to indemnifications and no payments or claims have been received from Anadarko related to indemnifications.

Services and Secondment Agreement

In connection with our initial public offering, Anadarko and our general partner entered into a services and secondment agreement pursuant to which specified employees of Anadarko are seconded to our general partner to provide operating, routine maintenance and other services with respect to our business under the direction, supervision and control of our general partner. Pursuant to the services and secondment agreement, our general partner reimburses Anadarko for the services provided by the seconded employees. The initial term of the services and secondment agreement is 10 years. The term will extend for additional 12-month periods unless either party provides 180 days written notice otherwise prior to the expiration of the applicable 12-month period. Either party may terminate the agreement at any time upon 180 days written notice.

Tax sharing agreement

In connection with our initial public offering, we entered into a tax sharing agreement pursuant to which we reimburse Anadarko for our share of Texas margin tax borne by Anadarko as a result of our results being included in a combined or consolidated tax return filed by Anadarko with respect to periods after May 14, 2008, the closing date of our initial public offering with respect to our initial assets and December 19, 2008 with respect to our Powder River assets. Anadarko may use its tax attributes to cause its combined or consolidated group, of which we may be a member for this purpose, to owe no tax. However, we would nevertheless reimburse Anadarko for the tax we would have owed had the attributes not been available or used for our benefit, even though Anadarko had no cash expense for that period.

Note from Anadarko

In connection with our initial public offering, we loaned $260.0 million to Anadarko. The note is a 30-year note bearing interest at a fixed annual rate of 6.5%, payable quarterly, with principal and all accrued and unpaid interest due in full at maturity.

Our working capital facility

In connection with our initial public offering, we entered into a $30.0 million two-year revolving credit facility with Anadarko as the lender. The facility is available exclusively to fund our working capital borrowings. Borrowings under the facility bear interest at the same rate as applies to borrowings under Anadarko s revolving credit facility. We pay a commitment fee of 0.11% annually to Anadarko on the unused portion of the working capital facility.

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

Contribution Agreement

On November 11, 2008, we and our subsidiaries entered into a contribution agreement with Anadarko and several of its affiliates. Pursuant to the contribution agreement, we acquired the Powder River assets from Anadarko, These assets provide a combination of gathering, treating and processing services in the Powder River Basin of Wyoming and are connected or adjacent to our MIGC pipeline. The consideration consisted of $175.0 million in cash, which was financed by borrowing $175.0 million from Anadarko pursuant to the terms of a five-year term loan agreement, 2,556,891 of our common units and 52,181 of our general partner units. The acquisition closed on December 19, 2008.

Pursuant to the Contribution Agreement, Anadarko has agreed to indemnify us and our respective affiliates (other than any of the entities controlled by Anadarko), shareholders, unitholders, members, directors, officers, employees, agents and representatives against certain losses resulting from any breach of Anadarko s representations, warranties, covenants or agreements, and for certain other matters. We have agreed to indemnify Anadarko and its respective affiliates (other than us and our respective security holders, officers, directors and employees) and their respective security holders, officers, directors and employees against certain losses resulting from any breach of our representations, warranties, covenants or agreements.

The board of directors of our general partner unanimously approved the Powder River acquisition, based in part on the unanimous recommendation in favor of the acquisition from, and the granting of special approval under our partnership agreement by, the board s special committee. The special committee, a committee of independent members of our general partner s board of directors, retained independent legal and financial advisors to assist it in evaluating and negotiating the acquisition. In recommending the approval of the acquisition, the special committee based its decision, in part, on the independent financial advisor s written opinion representing that the consideration to be paid by us to Anadarko was fair.

Term Loan Agreement

In connection with the Powder River acquisition, we entered into a term loan agreement under which Anadarko loaned $175.0 million to us to fund a portion of the acquisition cost. The term loan agreement has a term of five years and bears interest at a rate of 4% for the first two years. After the first two years, the term loan agreement calls for interest at a floating rate equal to LIBOR (defined in the agreement) plus 150 basis points. We have the option to repay the amount due in whole or in part commencing upon the second anniversary of the term loan agreement. The provisions of the term loan agreement are non-recourse to our general partner and our limited partners and contain customary events of default, including (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due; (ii) certain events of bankruptcy or insolvency with respect to the Partnership; or (iii) a change of control. The term loan agreement also contains a full guaranty of the amounts due by a wholly-owned subsidiary of Anadarko.

Commodity Price Swap Agreement

We entered into commodity price swap agreements with Anadarko in December 2008 to mitigate exposure to commodity price volatility that would otherwise be present as a result of our acquisition of the Hilight and Newcastle Systems. Specifically, the commodity price swap agreements fix the margin we will realize under percent-of-proceeds contracts applicable to natural gas processing activities at the Hilight and Newcastle Systems. In this regard, our notional volumes for each of the swap agreements are not specifically defined; instead, the commodity price swap agreements apply to volumes equal in amount to our share of actual volumes processed at the Hilight and Newcastle Systems. The commodity prices we will realize under the specified contracts are fixed for two years and we can extend the agreements, at our option, annually for three additional years.

Gas gathering agreements

Our gathering agreements with Anadarko accounted for approximately 86% of our gathering and transportation throughput for the year ended December 31, 2008. Approximately 90% of this affiliate throughput was sourced from natural gas volumes owned by Anadarko and its partners and the balance of throughput consists of volumes purchased from third parties by Anadarko Energy Services Company, Anadarko s wholly owned marketing affiliate.

Anadarko Petroleum Corporation. We entered into new gas gathering agreements with Anadarko effective January 1, 2008 for the gathering systems included in our initial assets. These agreements provide us with dedication of all of the natural gas owned or controlled by Anadarko and produced from (i) wells that are currently connected to our gathering systems, and (ii) additional wells that are drilled within one mile of wells connected to our gathering systems, as the systems currently exist and as they are expanded to connect additional wells in the future. As a result, this dedication will continue to expand as additional wells are connected to our gathering systems. Each gas gathering agreement is fee-based, and we provide gathering, compression, treating, dehydration and well connections within the dedicated area for a specified gathering fee. The gathering fee varies for each system and is subject to automatic annual escalators as well as other adjustments in the event Anadarko requests improvements to the level of service we currently provide under the agreement. Each of the gas gathering agreements has a 10-year primary term. After the expiration of the primary term, either party may request a re-determination of the gathering fee on an annual basis. If a fee re-determination occurs, the methodology which was utilized to determine the original gathering fee will also be utilized to determine the renegotiated fee, taking into account current production forecasts, capital expenditures and operating expenses. Our gathering agreements permit us to retain and sell condensate that is recovered from the gas stream during the gathering process. The gas gathering agreements are assignable by Anadarko to an affiliate without our consent and Anadarko will be permitted to sell the production which is dedicated to our systems to an affiliate or third-party purchaser, provided that the purchaser of the dedicated gas will be subject to the terms and conditions of our agreements and Anadarko will remain liable under the agreements in the event the purchaser defaults. The gathering fees we charge under our January 1, 2008 gas gathering agreements with Anadarko are higher than the fees reflected in our historical financial results for periods prior to January 1, 2008.

Anadarko Energy Services Company (AESC). AESC is Anadarko s marketing affiliate that purchases gas and is a shipper on our gathering systems. Approximately 10% of the affiliate throughput we gathered or transported for the year ended December 31, 2008 was comprised of third-party volumes purchased by AESC, and gathered under gathering agreements we have in place with AESC. We provide our services to AESC under fixed-fee arrangements whereby gathering fees and contract terms are based on a variety of factors, including gas quality and level of service provided. The terms of our agreements with AESC vary from month-to-month terms to 20-year terms.

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Gas purchase and sale agreements

All of the throughput volumes for the Hilight System and Newcastle System are sourced from third-party producers. However, substantially all natural gas, NGLs and condensate are sold to AESC pursuant to sales agreements. In addition, we purchase natural gas and NGLs from AESC pursuant to gas purchase agreements. Our gas purchase and sale agreements with AESC are generally one-year contracts, subject to annual renewal.

Transportation agreements

Western Gas Resources, Inc. and MGTC, Inc., affiliates of Anadarko, have contracted for 170,000 MMBtu/d of firm capacity on our MIGC system in agreements ranging in term from two years to 11 years. For the year ended December 31, 2008, our transportation agreements with Anadarko accounted for approximately 74% of the throughput on the MIGC system.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates, including Anadarko, on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, our general partner will resolve the conflict. Our partnership agreement contains provisions that modify and limit our general partner s fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions taken by our general partner that, without those limitations, might constitute breaches of its fiduciary duty. See *Item 10 Directors, Executive Officers and Corporate Governance Special committee* of this Form 10-K for more information.

Our general partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our unitholders if the resolution of the conflict is:

- approved by the special committee of our general partner, although our general partner is not obligated to seek such approval;

- 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 among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the special committee of its board of directors. In connection with a situation involving a conflict of interest, any determination by our general partner involving the resolution of the conflict of interest must be made in good faith, provided that, if our general partner does not seek approval from the special committee and its board of directors 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 special committee may consider any factors that it determines in good faith to be appropriate when resolving a conflict. Our partnership agreement provides that for someone to act in good faith, that person must reasonably believe he is acting in the best interests of the partnership.

Item 14. ***Principal Accounting Fees and Services***

We have engaged KPMG LLP as our independent registered public accounting firm. The following table summarizes fees we have paid KPMG LLP for independent auditing, tax and related services for each of the last two fiscal years:

	For Year Ended December 31,	
	2008	**2007**
	(in thousands)	
Audit Fees	$640	$
Audit-Related Fees	270	
Tax Fees		
All Other Fees		

Audit fees are primarily for the audit of the Partnership s consolidated financial statements, including reviews of the Partnership s financial statements included in the Form 10-Qs.

Audit-related fees are primarily for other audits, consents, comfort letters and certain financial accounting consultation.

The above amounts represent fees paid by the Partnership. Certain fees approved by Anadarko and reimbursed by the Partnership from initial public offering proceeds are not included in above amounts. The excluded amounts are $679,000 and $938,000 for 2008 and 2007, respectively, and are solely attributable to audit fees and audit-related fees for the Partnership s Predecessor for periods prior to its initial public offering.

Audit Committee Approval of Audit and Non-Audit Services

The Audit Committee of the Partnership s general partner has adopted a Pre-Approval Policy with respect to services which may be performed by KPMG LLP. This policy lists specific audit-related and tax services as well as any other services that KPMG LLP is authorized to perform and sets out specific dollar limits for each specific service, which may not be exceeded without additional Audit Committee authorization. The Audit Committee receives quarterly reports on the status of expenditures pursuant to that Pre-Approval Policy. The Audit Committee reviews the policy at least annually in order to approve services and limits for the current year. Any service that is not clearly enumerated in the policy must receive specific pre-approval by the Audit Committee or by its Chairman, to whom such authority has been conditionally delegated, prior to engagement.

The Audit Committee has approved the appointment of KPMG LLP as independent registered public accounting firm to conduct the audit of the Partnership s financial statements for the year ended December 31, 2009.

PART IV

Item 15. ***Exhibits***

(a)(1) *Financial Statements*

Our consolidated financial statements are included under Part II, Item 8 of this annual report. For a listing of these statements and accompanying footnotes, please see the *Index to Financial Statements* on page F-1 under Item 8 of this Form 10-K.

(a)(2) *Financial Statement Schedules*

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) *Exhibits*

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Exhibit Number	Description
3.1	Certificate of Limited Partnership of Western Gas Partners, LP (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.2	Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated May 14, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
3.3	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated December 19, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
3.4	Certificate of Formation of Western Gas Holdings, LLC (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.5	Amended and Restated Limited Liability Company Agreement of Western Gas Holdings, LLC, dated as of May 14, 2008 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
4.1	Specimen Unit Certificate for the Common Units (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP s Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).
10.1	Contribution, Conveyance and Assumption Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, Anadarko Petroleum Corporation, WGR Holdings, LLC, Western Gas Resources, Inc., WGR Asset Holding Company LLC, Western Gas Operating, LLC and WGR Operating, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.2#	Contribution Agreement, dated as of November 11, 2008, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on November 13, 2008, File No. 001-34046).
10.3	Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC and Anadarko Petroleum Corporation, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.3 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.4	Amendment No. 1 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of December 19, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).

10.5	Tax Sharing Agreement by and among Anadarko Petroleum Corporation and Western Gas Partners, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.5 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.6	Anadarko Petroleum Corporation Fixed Rate Note due 2038 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.7	Working Capital Loan Agreement between Anadarko Petroleum Corporation and Western Gas Partners, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.6 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).

Exhibit Number	Description
10.8	Revolving Credit Agreement, dated as of March 4, 2008, by and among Anadarko Petroleum Corporation, Western Gas Partners, LP, JPMorgan Chase Bank, N.A., The Royal Bank of Scotland, PLC, BNP Paribas, Bank of America, N.A., BMO Capital Markets Financing, Inc., The Bank of Tokyo-Mitsubishi UFJ, LTD., and each of the Lenders named therein (incorporated by reference to Exhibit 10.14 to Amendment No. 4 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on April 15, 2008, File No. 333-146700).
10.9	Term Loan Agreement due 2013 dated as of December 19, 2008 by and between Anadarko Petroleum Corporation and Western Gas Partners, LP (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
10.10	Dew Gas Gathering Agreement between Anadarko Gathering Company LLC and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on January 23, 2008, File No. 333-146700).
10.11	Haley Gas Gathering Agreement between Anadarko Gathering Company LLC and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 10.5 to Amendment No. 2 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on January 23, 2008, File No. 333-146700).
10.12	Hugoton Gas Gathering Agreement between Anadarko Gathering Company LLC and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 10.6 to Amendment No. 2 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on January 23, 2008, File No. 333-146700).
10.13	Pinnacle Gas Gathering Agreement between Pinnacle Gas Treating LLC and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 10.7 to Amendment No. 2 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on January 23, 2008, File No. 333-146700).
10.14	Form of Indemnification Agreement by and between Western Gas Holdings, LLC, its Officers and Directors (incorporated by reference to Exhibit 10.10 to Amendment No. 2 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on January 23, 2008, File No. 333-146700).
10.15	Western Gas Partners, LP 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.13 to Western Gas Partners, LP s Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).
10.16	Form of Award Agreement under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.17	Amended and Restated Western Gas Holdings, LLC Equity Incentive Plan (incorporated by reference to Exhibit 10.3 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
10.18	Form of Amended and Restated Award Agreement under Western Gas Holdings, LLC Equity Incentive Plan (incorporated by reference to Exhibit 10.4 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).

21.1*	List of Subsidiaries of Western Gas Partners, LP.
23.1*	Consent of KPMG LLP.
31.1*	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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Exhibit Number	Description
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

\# Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

Portions of this exhibit, which was previously filed with the Securities and Exchange Commission, were omitted pursuant to a request for confidential treatment. The omitted portions were filed separately with the Securities and Exchange Commission.

Management contracts or compensatory plans or arrangements required to be filed pursuant to

Item 15.

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.

Western Gas Partners, LP
(Registrant)

By: Western Gas Holdings, LLC,
its general partner

By: */s/ Michael C. Pearl*
Michael C. Pearl
Senior Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: March 12, 2009

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 indicated on March 12, 2009.

Signature	Title (Position with Western Gas Holdings, LLC)
/s/ Robert G. Gwin Robert G. Gwin	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Michael C. Pearl Michael C. Pearl	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Danny J. Rea Danny J. Rea	Senior Vice President, Chief Operating Officer and Director
/s/ R. A. Walker R. A. Walker	Chairman of Board and Director
/s/ Charles A. Meloy Charles A. Meloy	Director
/s/ Robert K. Reeves Robert K. Reeves	Director
/s/ Milton Carroll Milton Carroll	Director

/s/ Anthony R. Chase	Director
Anthony R. Chase	
/s/ James R. Crane	Director
James R. Crane	
/s/ David J. Tudor	Director
David J. Tudor	

Western Gas Partners, LP

Index to financial statements

Western Gas Partners, LP

Report of Independent Registered Public Accounting Firm

The Board of Directors

Western Gas Holdings, LLC (as general partner of Western Gas Partners, LP):

We have audited the accompanying consolidated balance sheets of Western Gas Partners, LP and subsidiaries (the Partnership) as of December 31, 2008 and 2007, and the related consolidated statements of income, parent net equity and partners capital, and cash flows for each of the years in the three-year period ended December 31, 2008. These consolidated financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these consolidated 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Western Gas Partners, LP and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas

March 12, 2009

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Western Gas Partners, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2008	**2007**[1]	**2006**[1]
	(in thousands, except per-unit data)		
Revenues affiliates			
Gathering, processing and transportation of natural gas	$ 107,582	$ 93,007	$ 66,296
Natural gas, natural gas liquids and condensate sales	154,772	146,151	52,959
Equity income and other	9,289	6,144	2,380
Total revenues affiliates	271,643	245,302	121,635
Revenues third parties			
Gathering, processing and transportation of natural gas	15,958	11,019	5,783
Natural gas, natural gas liquids and condensate sales	16,119	2,772	3
Other	7,928	2,400	1,189
Total revenues third parties	40,005	16,191	6,975
Total Revenues	311,648	261,493	128,610
Operating Expenses [2]			
Cost of product	134,715	112,283	41,806
Operation and maintenance	44,765	40,756	29,907
General and administrative	14,385	8,364	4,320
Property and other taxes	5,701	5,591	4,719
Depreciation	33,011	30,481	20,230
Impairment	9,354		
Total Operating Expenses	241,931	197,475	100,982
Operating Income	69,717	64,018	27,628
Interest income (expense), net affiliates	9,191	(7,805)	(9,574)
Other income (expense), net	145	(15)	(26)
Income Before Income Taxes	79,053	56,198	18,028
Income Tax Expense	13,777	19,540	5,327
Net Income	$ 65,276	$ 36,658	$ 12,701

Calculation of Limited Partner Interest in Net Income:			
Net income[3]	$ 42,103	n/a[4]	n/a
Less general partner interest in net income	842	n/a	n/a
Limited partner interest in net income	$ 41,261	n/a	n/a
Net income per limited partner unit basic	$ 0.78	n/a	n/a
Net income per limited partner unit diluted	$ 0.77		
Limited partner units outstanding basic	53,216	n/a	n/a
Limited partner units outstanding diluted	53,246	n/a	n/a

(1) Financial information for 2007 and 2006 has been revised to include results attributable to the Powder River assets from August 23, 2006. See *Note 3 Powder River Acquisition*.

(2) Operating expenses include amounts charged by affiliates to the Partnership for services as well as reimbursement of amounts paid by affiliates to third parties on behalf of the Partnership. Cost of product expenses include product purchases from affiliates of $23.6 million, $18.8 million and $8.7 million for the years ended December 31,

2008, 2007 and 2006, respectively. Operation and maintenance expenses include charges from affiliates of $17.8 million, $11.7 million and $6.5 million for the years ended December 31, 2008, 2007 and 2006, respectively. General and administrative expenses include charges from affiliates of $11.1 million, $8.4 million and $4.3 million for the years ended December 31, 2008, 2007 and 2006, respectively. See *Note 6 Transactions with Affiliates.*

(3) Reflective of net income since the Partnership s initial public offering on May 14, 2008. See *Note 5 Net Income per Limited Partner Unit.*

(4) Not applicable

See accompanying notes to the consolidated financial statements.

Western Gas Partners, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007[1]
	(in thousands, except number of units)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 33,306	$
Accounts receivable, net third parties	5,878	5,066
Accounts receivable affiliates	3,235	
Natural gas imbalance receivables third parties	389	899
Natural gas imbalance receivables affiliates	1,422	
Inventory	644	777
Deferred income taxes	14	2,916
Other current assets	491	
Total current assets	45,379	9,658
Other assets	628	27
Note receivable Anadarko	260,000	
Property, Plant and Equipment		
Cost	680,591	641,123
Less accumulated depreciation	162,776	129,348
Net property, plant and equipment	517,815	511,775
Goodwill	14,436	12,347
Equity investment	18,183	10,511
Total Assets	$ 856,441	$ 544,318
LIABILITIES, PARTNERS CAPITAL AND PARENT NET EQUITY		
Current Liabilities		
Accounts payable	$ 5,544	$ 3,737
Natural gas imbalance payable third parties	244	2,104
Natural gas imbalance payable affiliates	1,198	
Accrued ad valorem taxes	1,330	1,298
Income taxes payable	146	313
Accrued liabilities third parties	7,726	4,925
Accrued liabilities affiliates	153	
Total current liabilities	16,341	12,377
Long-Term Liabilities		
Note payable Anadarko	175,000	
Deferred income taxes	1,053	129,267

Asset retirement obligations and other	9,093	10,534
Total long-term liabilities	185,146	139,801
Total Liabilities	201,487	152,178
Commitments and Contingencies (Note 13)		
Parent Net Equity and Partners Capital		
Common units (29,093,197 units issued and outstanding at December 31, 2008)	368,049	
Subordinated units (26,536,306 units issued and outstanding at December 31, 2008)	275,917	
General partner units (1,135,296 units issued and outstanding at December 31, 2008)	10,988	
Parent net investment		392,140
Total Parent Net Equity and Partners Capital	654,954	392,140
Total Liabilities, Parent Net Equity and Partners Capital	$ 856,441	$ 544,318

(1) Financial information as of December 31, 2007 has been revised to include assets, liabilities and parent net equity attributable to the Powder River assets. See *Note 3 Powder River Acquisition.*

See accompanying notes to the consolidated financial statements.

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Western Gas Partners, LP
CONSOLIDATED STATEMENT OF PARENT NET EQUITY AND PARTNERS CAPITAL

	Parent Net	Partners Capital			
		Limited Partners			
	Investment	Common	Subordinated	General Partner	Total
			(in thousands)		
Balance at December 31, 2005	$ 160,585	$	$	$	$ 160,585
Net contributions from parent	10,113				10,113
Acquisition of MIGC	52,390				52,390
Powder River acquisition	116,789				116,789
Net income	12,701				12,701
Balance at December 31, 2006[(1)]	$ 352,578	$	$	$	$ 352,578
Contribution of property from parent	21,942				21,942
Net distributions to parent	(19,038)				(19,038)
Net income	36,658				36,658
Balance at December 31, 2007[(1)]	$ 392,140	$	$	$	$ 392,140
Reimbursement to parent from offering proceeds	(45,161)				(45,161)
Elimination of net deferred tax liabilities	126,936				126,936
Net income attributable to Predecessor	23,173				23,173
Net distributions to parent	(16,717)				(16,717)
Contribution of net assets to Western Gas Partners, LP	(321,609)	55,221	255,941	10,447	
Contribution of assets from parent	2,089	2,528	11,715	478	16,810
Issuance of common units to public, net of offering and other costs		315,161			315,161
Contribution of Powder River assets	(160,851)	(13,866)		(283)	(175,000)
Non-cash equity-based compensation		323			323
Net income attributable to Partners		20,841	20,420	842	42,103
Distributions to unitholders		(12,159)	(12,159)	(496)	(24,814)
Balance at December 31, 2008	$	$ 368,049	$ 275,917	$ 10,988	$ 654,954

(1)

Financial information for 2007 and 2006 has been revised to include activity attributable to the Powder River assets from August 23, 2006. See *Note 3 Powder River Acquisition*.

See accompanying notes to the consolidated financial statements.

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Western Gas Partners, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007[1]	2006[1]
		(in thousands)	
Cash Flows from Operating Activities			
Net income	$ 65,276	$ 36,658	$ 12,701
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	33,011	30,481	20,230
Impairment	9,354		
Deferred income taxes	1,624	10,816	3,226
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(4,047)	(3,466)	2,037
(Increase) in natural gas imbalance receivable	(912)	(226)	
Increase (decrease) in accounts payable and accrued expenses	4,840	142	(4,312)
Increase (decrease) in other items, net	650	(1,497)	(578)
Net cash provided by operating activities	109,796	72,908	33,304
Cash Flows from Investing Activities			
Capital expenditures	(36,864)	(54,328)	(42,963)
Powder River acquisition	(175,000)		
Investment in equity affiliate	(8,095)		
Loan to Anadarko	(260,000)		
Net cash used in investing activities	(479,959)	(54,328)	(42,963)
Cash Flows from Financing Activities			
Proceeds from issuance of common units, net of $5.9 million in offering expenses	315,161		
Issuance of Note Payable to Anadarko	175,000		
Reimbursement to parent from offering proceeds	(45,161)		
Distributions to unitholders	(24,814)		
Net (distributions to) contributions from parent	(16,717)	(19,038)	10,113
Net cash provided by (used in) financing activities	403,469	(19,038)	10,113
Net Increase (Decrease) in Cash and Cash Equivalents	33,306	(458)	454
Cash and Cash Equivalents at Beginning of Period		458	4
Cash and Cash Equivalents at End of Period	$ 33,306	$	$ 458
Supplemental Disclosures			
Significant non-cash investing and financing transactions:			
Contribution of initial assets to Western Gas Partners, LP from parent	$ 321,609	$	$
	14,149		

Value of consideration paid in excess of net carrying value of Powder River assets			
Elimination of net deferred tax liabilities	126,936		
Property, plant and equipment contributed by parent	14,721	21,942	
(Increase) decrease in accrued capital expenditures	876	(501)	(1,876)

(1) Financial information for 2007 and 2006 has been revised to include activity attributable to the Powder River assets from August 23, 2006. See *Note 3 Powder River Acquisition*.

See accompanying notes to the consolidated financial statements.

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Notes to consolidated financial statements of Western Gas Partners, LP

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION

Western Gas Partners, LP (the Partnership) is a Delaware limited partnership formed in August 2007. The Partnership s assets consist of nine gathering systems, six natural gas treating facilities, two gas processing facilities and one interstate pipeline. The Partnership s assets are located in East and West Texas, the Rocky Mountains (Utah and Wyoming) and the Mid-Continent (Kansas and Oklahoma). The Partnership is engaged in the business of gathering, compressing, processing, treating and transporting natural gas for Anadarko Petroleum Corporation and its consolidated subsidiaries (Anadarko) and third-party producers and customers. The Partnership s general partner is Western Gas Holdings, LLC, a wholly owned subsidiary of Anadarko.

On May 14, 2008, the Partnership closed its initial public offering of 18,750,000 common units at a price of $16.50 per unit. On June 11, 2008, the Partnership issued an additional 2,060,875 common units to the public pursuant to the partial exercise of the underwriters over-allotment option. The May 14 and June 11 issuances are referred to collectively as the initial public offering. The common units are listed on the New York Stock Exchange under the symbol WES. The Partnership received gross proceeds of $343.4 million from the initial public offering, less $22.3 million for underwriting discounts and structuring fees. The Partnership used the balance of the gross offering proceeds as follows:

- approximately $5.9 million to pay offering expenses;
- approximately $45.2 million to reimburse Anadarko from offering proceeds;
- $260.0 million loaned to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%; and
- $10.0 million retained for general partnership purposes.

Concurrent with the closing of the initial public offering, Anadarko contributed the assets and liabilities of Anadarko Gathering Company LLC (AGC), Pinnacle Gas Treating LLC (PGT) and MIGC LLC (MIGC) to the Partnership in exchange for 1,083,115 general partner units, representing a 2.0% general partner interest in the Partnership, 100% of the Incentive Distribution Rights (IDRs), 5,725,431 common units and 26,536,306 subordinated units. AGC, PGT and MIGC are referred to collectively as the initial assets. The common units issued to Anadarko include 751,625 common units issued following the expiration of the underwriters over-allotment option and represent the portion of the common units which were not exercised by the underwriters under the option. IDRs entitle the holder to specified increasing percentages of cash distributions as the Partnership s per-unit cash distributions increase. See *Note 4 Partnership Equity and Distributions* for information related to the distribution rights of the common and subordinated unitholders and to the IDRs held by the general partner.

On December 19, 2008, the Partnership acquired certain midstream assets from Anadarko for consideration consisting of $175.0 million cash, which was financed by borrowing $175.0 million from Anadarko pursuant to the terms of a five-year term loan agreement, 2,556,891 common units and 52,181 general partner units. The acquisition consisted of (i) a 100% ownership interest in the Hilight System, (ii) a 50% interest in the Newcastle System and (iii) a 14.81% limited liability company membership interest in Fort Union Gas Gathering, L.L.C. (Fort Union). These assets are referred to collectively as the Powder River assets and the acquisition is referred to as the Powder River acquisition. Please see *Note 3 Powder River Acquisition.*

As of December 31, 2008, Anadarko holds 1,135,296 general partner units representing a 2.0% general partner interest in the Partnership, 100% of the Partnership incentive distribution rights, 8,282,322 common units and 26,536,306 subordinated units. Anadarko s common and subordinated unit ownership represents an aggregate 61.3% limited partner interest in the Partnership. The public holds 20,810,875 common units, representing a 36.7% limited partner interest in the Partnership.

The acquisition of the initial assets and the Powder River assets are considered transfers of net assets between entities under common control. Anadarko acquired MIGC and the Powder River assets in connection with its August 23, 2006 acquisition of Western Gas Resources, Inc. The accompanying consolidated financial statements of the Partnership have been prepared in accordance with accounting principles generally accepted in the United States. The Partnership as used herein refers to the combined financial results and operations of AGC and PGT from their inception through May 14, 2008 and to the Partnership thereafter, combined with the financial results and operations of MIGC and the Powder River assets from August 23, 2006 thereafter. Western refers to

Notes to consolidated financial statements of Western Gas Partners, LP

Western Gas Resources, Inc. and its consolidated subsidiaries prior to Anadarko s acquisition of Western and Parent refers to Western for periods prior to August 23, 2006 and to Anadarko for periods including and subsequent to August 23, 2006. The consolidated financial statements for periods prior to May 14, 2008 with respect to the initial assets and prior to December 19, 2008 with respect to the Powder River assets have been prepared from Anadarko s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the assets and operated as a separate entity during the periods reported. In addition to recasting the Partnership s financial statements for the years ended December 31, 2007 and 2006 for the Powder River assets, certain amounts in prior periods have been reclassified to conform to the current presentation.

The consolidated financial statements include the accounts of the Partnership and entities in which it holds a controlling financial interest. All significant intercompany transactions have been eliminated. Investments in non-controlled entities over which Anadarko exercises significant influence are accounted for using the equity method. The information furnished herein reflects all normal recurring adjustments that are, in the opinion of management, necessary for a fair statement of financial position as of December 31, 2008 and 2007 and for the results of operations, changes in partners capital and parent net equity and cash flows for each of the years in the three-year period ended December 31, 2008.

Certain costs of doing business incurred by Anadarko on behalf of the Partnership have been reflected in the accompanying financial statements. These costs include general and administrative expenses charged by Anadarko to the Partnership in exchange for:

- business services, such as payroll, accounts payable and facilities management;
- corporate services, such as finance and accounting, marketing, legal, human resources, investor relations and public and regulatory policy;
- executive compensation, but not including share-based compensation for periods ending prior to May 14, 2008; and
- pension and other post-retirement benefit costs.

Transactions between the Partnership and Anadarko have been identified in the consolidated financial statements as transactions between affiliates. Please see *Note 6 Transactions with Affiliates.*

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of estimates

To conform to accounting principles generally accepted in the United States, management makes estimates and assumptions that affect the amounts reported in the consolidated financial statements and the notes thereto. These estimates are evaluated on an ongoing basis, utilizing historical experience and other methods considered reasonable in the particular circumstances. Although these estimates are based on management s best available knowledge at the time, actual results may differ.

Effects on the Partnership s business, financial position and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revision become known. Changes in facts and circumstances or discovery of new facts or circumstances may result in revised estimates and actual results may differ from these estimates.

Property, plant and equipment

Property, plant and equipment are stated at the lower of historical cost less accumulated depreciation or fair value, if impaired. The Partnership capitalizes all construction-related direct labor and material costs. The cost of renewals and betterments that extend the useful life of property, plant and equipment is also capitalized. The cost of repairs, replacements and major maintenance projects which do not extend the useful life or increase the expected output of property, plant and equipment is expensed as incurred.

Depreciation is computed over the asset s estimated useful life using the straight-line method or half-year convention method, based on estimated useful lives and salvage values of assets. Uncertainties that may impact these estimates include, among others, changes in laws and regulations relating to restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are placed into service, the Partnership makes estimates with respect to

Notes to consolidated financial statements of Western Gas Partners, LP

useful lives and salvage values that the Partnership believes are reasonable. However, subsequent events could cause a change in estimates, thereby impacting future depreciation amounts.

The Partnership evaluates its ability to recover the carrying amount of its long-lived assets and determines whether its long-lived assets have been impaired. Impairment exists when the carrying amount of an asset exceeds estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, estimates of future undiscounted cash flows take into account possible outcomes and probabilities of their occurrence. If the carrying amount of the long-lived asset is not recoverable, based on the estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset s carrying amount over its estimated fair value, such that the asset s carrying amount is adjusted to its estimated fair value with an offsetting charge to operating expense.

Fair value represents the estimated price between market participants to sell an asset in the principal or most advantageous market for the asset, based on assumptions a market participant would make. When warranted, management assesses the fair value of long-lived assets using commonly accepted techniques and may use more than one source in making such assessments. Sources used to determine fair value include, but are not limited to, recent third-party comparable sales, internally developed discounted cash flow analyses and analyses from outside advisors. Significant changes, such as changes in contract rates or terms, the condition of an asset, or management s intent to utilize the asset generally require management to reassess the cash flows related to long-lived assets.

During the year ended December 31, 2008, an impairment charge was recorded in connection with the shut-in of a plant at the Hilight System prior to its contribution to the Partnership.

Equity-Method Investment

Fort Union is a partnership among Copano Pipelines/Rocky Mountains, LLC (37.04%), Crestone Powder River L.L.C. (37.04%), Bargath, Inc. (11.11%) and the Partnership (14.81%). Fort Union owns a gathering pipeline and treating facilities in the Powder River Basin. The Parent is the construction manager and physical operator of the Fort Union facilities.

The Partnership s investment in Fort Union is accounted for under the equity method of accounting. Certain business decisions, including, but not limited to, decisions with respect to significant expenditures or contractual commitments, annual budgets, material financings, dispositions of assets or amending the owners firm gathering agreements, require 65% or unanimous approval of the owners.

Management evaluates its equity-method investment for impairment whenever events or changes in circumstances indicate that the carrying value of such investment may have experienced a decline in value that is other than temporary. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether the investment has been impaired. Management assesses the fair value of equity-method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

The investment balance at December 31, 2008 includes $3.0 million for the purchase price allocated to the investment in Fort Union in excess of Western s historic cost basis. This balance was attributed to the difference between the fair value and book value of Fort Union s gathering and treating facilities and is being amortized over the remaining life of those facilities. Investment earnings from Fort Union, net of investment amortization, are reported in equity income and other revenues affiliates in the statements of income.

At December 31, 2008, Fort Union had expansion projects under construction and had project financing debt of $117.1 million outstanding, which is not guaranteed by the members. Fort Union s lender has a lien on the Partnership s interest in Fort Union.

Goodwill

Goodwill represents the excess of the purchase price of an entity over the estimated fair value of the identifiable assets acquired and liabilities assumed. During 2006, the Partnership recognized $4.8 million of goodwill in connection with the acquisition of MIGC and attributed this amount to the Partnership s transportation reporting unit and recognized

$9.6 million

Notes to consolidated financial statements of Western Gas Partners, LP

of goodwill in connection with the Powder River acquisition and attributed this amount to the Partnership s gathering and processing reporting unit. None of this goodwill is deductible for income tax purposes.

The Partnership evaluates whether goodwill has been impaired. Impairment testing is performed annually as of October 1, unless facts and circumstances make it necessary to test more frequently. The Partnership has determined that it has one operating segment and two reporting units and, accordingly, goodwill is assessed for impairment at the reporting unit level. Goodwill impairment assessment is a two-step process. Step one focuses on identifying a potential impairment by comparing the fair value of the reporting unit with the carrying amount of the reporting unit. If the fair value of the reporting unit exceeds its carrying amount, no further action is required. However, if the carrying amount of the reporting unit exceeds its fair value, goodwill is written down to the implied fair value of the goodwill through a charge to operating expense based on a hypothetical purchase price allocation.

No goodwill impairment has been recognized in these consolidated financial statements.

Asset retirement obligations

Management recognizes a liability based on the estimated costs of retiring tangible long-lived assets. The liability is recognized at its fair value measured using expected discounted future cash outflows of the asset retirement obligation when the obligation originates, which generally is when an asset is acquired or constructed. The carrying amount of the associated asset is increased commensurate with the liability recognized. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. Subsequent to the initial recognition, the liability is adjusted for any changes in the expected value of the retirement obligation (with a corresponding adjustment to property, plant and equipment) and for accretion of the liability due to the passage of time, until the obligation is settled. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded for both the asset retirement obligation and the associated asset carrying amount. Revisions in estimated asset retirement obligations may result from changes in estimated inflation rates, discount rates, retirement costs and the estimated timing of settling asset retirement obligations.

Revenue recognition

Under its fee-based arrangements, the Partnership is paid a fixed fee based on the volume and thermal content of the natural gas it gathers or treats and recognizes gathering and treating revenues for its services at the time the service is performed.

Producers wells are connected to the Partnership s gathering systems for delivery of natural gas to the Partnership s processing or treating plants, where the natural gas is processed to extract NGLs or treated in order to satisfy pipeline specifications. In some areas, where no processing is required, the producers gas is gathered, compressed and delivered to pipelines for market delivery. Except for volumes taken in-kind by certain producers, an affiliate of Anadarko sells the natural gas and extracted NGLs attributable to processing activities at the Hilight System and the Newcastle System. Under percent-of-proceeds contracts, revenue is recognized when the natural gas or NGLs are sold and the related product purchases are recorded as a percentage of the product sale.

Under keep-whole contracts, NGLs recovered by the processing facility are retained and sold. Producers are kept whole through the receipt of a thermally equivalent volume of residue gas at the tailgate of the plant. The keep-whole contract conveys an economic benefit to the Partnership when the individual values of the NGLs are greater as liquids than as a component of the natural gas stream; however, the Partnership is adversely impacted when the value of the NGLs are lower as liquids than as a component of the natural gas stream. Revenue is recognized from the NGLs upon transfer of title.

Condensate recovered in the field and during processing is retained and sold. Depending upon contract terms, proceeds from condensate sales are either retained by the gatherer or processor or is credited to the producer. Revenue is recognized from the sale of condensate upon transfer of title.

The Partnership earns transportation revenues through firm contracts that obligate each of its customers to pay a monthly reservation or demand charge regardless of the pipeline capacity used by that customer. An additional commodity usage fee is charged to the customer based on the actual volume of natural gas transported. Revenues are also generated from interruptible contracts pursuant to which a fee is charged to the customer based on volumes transported through the pipeline. Revenues for transportation of natural gas are recognized over the period of firm transportation contracts or, in the case of usage fees and interruptible contracts, when the volumes are received into the pipeline. From time to time, certain revenues

Notes to consolidated financial statements of Western Gas Partners, LP

may be subject to refund pending the outcome of rate matters before the Federal Energy Regulatory Commission and reserves are established where appropriate. During the periods presented herein, there were no pending rate cases and no related reserves have been established.

Proceeds from the sale of residue gas, NGLs and condensate are recorded in natural gas, natural gas liquids and condensate revenues in the statements of income. Revenues attributable to the fixed-fee component of gathering and processing contracts as well as demand charges and commodity usage fees on transportation contracts are reported in gathering, processing and transportation of natural gas revenues in the statements of income.

Natural gas imbalances

The consolidated balance sheets include natural gas imbalance receivables and payables resulting from differences in gas volumes received into the Partnership s systems and gas volumes delivered by the Partnership to customers. Natural gas volumes owed to or by the Partnership that are subject to monthly cash settlement are valued according to the terms of the contract as of the balance sheet dates, and generally reflect market index prices. Other natural gas volumes owed to or by the Partnership are valued at the Partnership s weighted average cost of natural gas as of the balance sheet dates and are settled in-kind. As of December 31, 2008, natural gas imbalance receivables and payables were approximately $1.8 million and $1.4 million, respectively. As of December 31, 2007, natural gas imbalance receivables and payables were approximately $0.9 million and $2.1 million, respectively. Changes in natural gas imbalances are reported in other revenues or cost of product expense in the statements of income.

Inventory

The cost of natural gas and NGLs inventories are determined by the weighted average cost method on a location-by-location basis. Inventory is accounted for at the lower of weighted average cost or market value.

Environmental expenditures

The Partnership expenses environmental expenditures related to conditions caused by past operations that do not generate current or future revenues. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Liabilities are recorded when the necessity for environmental remediation becomes probable and the costs can be reasonably estimated, or when other potential environmental liabilities are probable and can be reasonably estimated.

Cash equivalents

The Partnership considers all highly liquid investments with an original maturity date of three months or less to be cash equivalents. The Partnership had approximately $33.3 million of cash and cash equivalents as of December 31, 2008 and no cash or cash equivalents as of December 31, 2007.

Bad-debt reserve

The Partnership revenues are primarily from Anadarko, for which no credit limit is maintained. The Partnership analyzes its exposure to bad debt on a customer-by-customer basis for its third-party accounts receivable and may establish credit limits for significant third-party customers. For third-party accounts receivable, the amount of bad-debt reserve at December 31, 2008 and December 31, 2007 was approximately $53,000 and $41,000, respectively.

Equity-based compensation

Concurrent with the closing of the initial public offering, phantom unit awards were granted to independent directors of the general partner under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (LTIP), which permits the issuance of up to 2,250,000 units. Upon vesting of each phantom unit, the holder will receive common units of the Partnership or, at the discretion of the general partner s board of directors, cash in an amount equal to the market value of common units of the Partnership on the vesting date. Share-based compensation expense attributable to grants made pursuant to the LTIP will impact the Partnership s cash flow from operating activities only to the extent the general partner s board of directors elects to make a cash payment to a participant in lieu of the issuance of common units upon the lapse of the vesting period.

Notes to consolidated financial statements of Western Gas Partners, LP

Statement of Financial Accounting Standards (SFAS) No. 123(R), *Share-Based Payment (revised 2004)* (SFAS 123(R)), requires companies to recognize stock-based compensation as an operating expense. The Partnership amortizes stock-based compensation expense attributable to awards granted under the LTIP over the vesting periods applicable to the awards.

Additionally, the Partnership s general and administrative expenses include equity-based compensation costs allocated by Anadarko to the Partnership for grants made pursuant to the Western Gas Holdings, LLC Equity Incentive Plan as amended and restated (Incentive Plan) as well as the Anadarko Petroleum Corporation 1999 Stock Incentive Plan and the Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan (Anadarko s plans are referred to collectively as the Anadarko Incentive Plans). Under the Incentive Plan, participants are granted Unit Value Rights (UVRs), Unit Appreciation Rights (UARs) and Dividend Equivalent Rights (DERs). UVRs granted under the Incentive Plan are valued at $50 per UVR, vest ratably over three years, or earlier in connection with certain other events, and become payable in cash by the general partner no later than 30 days subsequent to vesting. UARs granted under the Incentive Plan vest ratably over three years or earlier in connection with certain other events, become payable no later than 30 days subsequent to exercise by the participant and expire upon the earlier of the 90th day subsequent to the participant s voluntary termination or 10 years from the date of grant. DERs granted under the Incentive Plan vest upon the occurrence of certain events, become payable no later than 30 days subsequent to vesting and expire 10 years from the date of grant. Equity-based compensation expense attributable to grants made pursuant to the Incentive Plan will impact the Partnership s cash flow from operating activities only to the extent cash payments are made to Incentive Plan participants and such cash payments do not cause total annual reimbursements made by the Partnership to Anadarko pursuant to the omnibus agreement to exceed the general and administrative expense limit set forth therein for the periods to which such expense limit applies. See *Note 6 Transactions with Affiliates*.

Income taxes

The Partnership generally is not subject to federal or state income tax. The Partnership is subject to a Texas margin tax and recognizes this tax expense in its consolidated financial statements. Prior to closing of the initial public offering, tax expense was recorded for income generated by the initial assets and, prior to closing of the Powder River acquisition, tax expense was recorded for income generated by the Powder River assets. For periods prior to May 14, 2008 with respect to the initial assets and for periods prior to December 19, 2008 with respect to the Powder River assets, deferred federal and state income taxes were provided on temporary differences between the financial statement carrying amounts of recognized assets and liabilities and their respective tax bases as if the Partnership filed tax returns as a stand-alone entity. For periods subsequent to May 14, 2008, the Partnership will make payments to Anadarko pursuant to the tax sharing arrangement entered into between Anadarko and the Partnership for its share of Texas margin tax that are included in any combined or consolidated returns filed by Anadarko. The aggregate difference in the basis of our assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each partner s tax attributes in us.

Financial Accounting Standards Board (FASB) Financial Interpretation No. 48, *Accounting for uncertainty in Income Taxes an interpretation of FASB Statement No. 109* (FIN 48), became effective January 1, 2007. FIN 48 defines the criteria an individual tax position must meet for any part of the benefit of that position to be recognized in the financial statements. The Partnership has no material uncertain tax positions at December 31, 2008 or 2007.

Net income per limited partner unit

Emerging Issues Task Force (EITF) Issue 03-6, *Participating Securities and the Two-Class Method Under FASB Statement No. 128* (EITF 03-6), addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and undistributed earnings of the entity when, and if, it declares dividends on its securities. EITF 03-6 requires securities that satisfy the definition of a participating security to be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed pursuant to the terms of the relevant contractual arrangement. For the Partnership, earnings per unit is calculated based on the assumption that the Partnership distributes to its unitholders an amount of cash equal to the net income of the Partnership, notwithstanding the general partner s ultimate discretion over the amount of cash to be distributed for the period, the existence of other legal or contractual limitations that would prevent distributions of all of the net income for the period or any other economic or practical limitation on the ability to make a full distribution of all of the net income for the period. Earnings per unit is calculated by applying the provisions of the partnership agreement that govern actual cash distributions to the notional cash distribution amount, including giving effect to incentive distributions.

Notes to consolidated financial statements of Western Gas Partners, LP

New accounting standards

The following new accounting standards were adopted by the Partnership during the three-year period ended December 31, 2008:

SFAS No. 157, Fair Value Measurements (SFAS 157). In September 2006, the FASB issued SFAS 157, which defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS 157 does not require any new fair value measurements. However, in some cases, the application of SFAS 157 changed the Partnership s historical practice for measuring fair values under other accounting pronouncements that require or permit fair value measurements. As originally issued, SFAS 157 was effective as of January 1, 2008 and must be applied prospectively, except in certain cases, to the Partnership. The FASB issued FSP FAS 157-2, which delayed the effective date of SFAS 157 to January 1, 2009 for nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The Partnership adopted SFAS 157 effective January 1, 2008. Adoption of SFAS 157 did not have a material impact on the Partnership s consolidated results of operations, cash flows or financial position.

Recently issued accounting standards not yet adopted

The following new accounting standards have been issued, but had not been adopted by the Partnership as of December 31, 2008:

SFAS No. 141 (revised 2007), Business Combinations (SFAS 141(R)). In December 2007, the FASB issued SFAS 141(R) which applies fair value measurement in accounting for business combinations, expands financial disclosures, defines an acquirer and modifies the accounting for some business combinations items. Under SFAS 141(R), an acquirer will be required to record 100% of assets and liabilities, including goodwill, contingent assets and contingent liabilities, at their fair value. This replaces the cost allocation process applied under SFAS No. 141, *Business Combinations* (SFAS 141). In addition, contingent consideration must also be recognized at fair value at the acquisition date. Acquisition-related costs will be expensed rather than treated as an addition to the assets being acquired and restructuring costs will be recognized separately from the business combination. SFAS 141(R) will apply to the Partnership prospectively for business combinations with an acquisition date on or after January 1, 2009.

EITF Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships (EITF 07-4), and FASB Staff Position EITF Issue No. 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). In March 2008, the EITF issued EITF 07-4 addressing the application of the two-class method under SFAS No. 128, *Earnings per Share* (SFAS 128), in determining income per unit for master limited partnerships having multiple classes of securities including limited partnership units, general partnership units and, when applicable, IDRs of the general partner. EITF 07-4 clarifies that the two-class method would apply. Further, EITF 07-4 states that undistributed earnings should be allocated to the general partner, limited partners and IDR holders as if undistributed earnings were available cash. In June 2008, the FASB issued FSP EITF 03-6-1 addressing whether instruments granted in share-based payment transactions are participating securities prior to vesting and therefore required to be accounted for in calculating earnings per unit under the two-class method described in SFAS 128. FSP EITF 03-6-1 requires companies to treat unvested share-based payment awards that have non-forfeitable rights to dividend or dividend equivalents as a separate class of securities in calculating earnings per unit. The Partnership is evaluating the impact of EITF 07-4 and FSP EITF 03-6-1 on the Partnership s reported earnings per unit. EITF 07-4 and FSP EITF 03-6-1 are effective for the Partnership on January 1, 2009 and will be applied with respect to all periods in which earnings per unit is presented.

EITF Issue No. 08-6, Accounting for Equity Method Investments Considerations (EITF 08-6). In November 2008, the EITF issued EITF 08-6, which clarifies that an equity method investor is required to continue to recognize an other-than-temporary impairment of its investment in accordance with Accounting Principles Board Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock*. Also, an equity method investor should not separately test an investee s underlying assets for impairment. However, an equity method investor should recognize its share of an impairment charge recorded by an investee. EITF 08-6 will be effective for the Partnership on a prospective basis on January 1, 2009 and for interim periods beginning with the first quarter of 2009.

Notes to consolidated financial statements of Western Gas Partners, LP

3. POWDER RIVER ACQUISITION

In December 2008, the Partnership acquired the Powder River assets from Anadarko for consideration consisting of $175.0 million cash, which was financed by borrowing $175.0 million from Anadarko pursuant to the terms of a five-year term loan agreement, 2,556,891 common units and 52,181 general partner units. These assets provide a combination of gathering, treating and processing services in the Powder River Basin.

The Partnership accounted for the Powder River acquisition as a transfer of net assets between entities under common control pursuant to the provisions of SFAS 141, Appendix D. The Powder River assets were recorded at the amounts reflected in Anadarko s historical consolidated financial statements, including an allocation of goodwill. The difference between the purchase price and Anadarko s carrying value of the combined net assets acquired and liabilities assumed was recorded as an adjustment to partners capital. SFAS 141 also requires that all income statements be revised to include the results of the acquired assets as of the date of common control. Accordingly, the Partnership s historical financial statements have been recast for periods including and subsequent to August 23, 2006, the date Anadarko acquired the Powder River assets through its acquisition of Western.

4. PARTNERSHIP EQUITY AND DISTRIBUTIONS

The partnership agreement requires that, within 45 days subsequent to the end of each quarter, beginning with the quarter ended June 30, 2008, the Partnership distribute all of its available cash (described below) to unitholders of record on the applicable record date. The Partnership paid cash distributions to its unitholders of $0.4582 per unit during the year ended December 31, 2008. This amount consists of a $0.30 per unit quarterly distribution prorated for the 48-day period beginning on May 14, 2008 and ending on June 30, 2008, or $0.1582 per unit, and a $0.30 per unit distribution for the quarter ended on September 30, 2008. See also *Note 15 Subsequent Event* concerning distributions approved in January 2009.

Available cash

The amount of available cash (as defined in the partnership agreement) generally is 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 to fund future capital expenditures, to comply with applicable laws, our debt instruments or other agreements, or to provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters. Working capital borrowings generally include borrowings made under a credit facility or similar financing arrangement. It is intended that working capital borrowings be repaid within 12 months. In all cases, working capital borrowings are used solely for working capital purposes or to fund distributions to partners.

Minimum quarterly distributions

The partnership agreement provides that, during a period of time referred to as the subordination period, the common units are entitled to distributions of available cash each quarter in an amount equal to the minimum quarterly distribution, which is $0.30 per common unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash are permitted on the subordinated units. Furthermore, arrearages do not apply to subordinated units and therefore will not be paid on the subordinated units. The effect of the subordinated units is to increase the likelihood that, during the subordination period, available cash is sufficient to fully fund cash distributions on the common units in an amount equal to the minimum quarterly distribution.

The subordination period will lapse at such time when the Partnership has paid at least $0.30 per quarter on each common unit, subordinated unit and general partner unit for any three consecutive, non-overlapping four-quarter periods ending on or after June 30, 2011. Also, if the Partnership has paid at least $0.45 per quarter (150% of the minimum quarterly distribution) on each outstanding common unit, subordinated unit and general partner unit for each calendar quarter in a four-quarter period, the subordination period will terminate automatically. The subordination period will also terminate automatically if the general partner is removed without cause and the units held by the general partner and its affiliates are not voted in favor of such removal. When the subordination period lapses or otherwise terminates, all remaining subordinated units will convert into common units on a one-for-one basis and the common units will no longer be entitled to preferred distributions on prior-quarter distribution arrearages. All subordinated units are held indirectly by Anadarko.

Notes to consolidated financial statements of Western Gas Partners, LP

General partner interest and incentive distribution rights

The general partner is currently entitled to 2.0% of all quarterly distributions that the Partnership makes prior to its liquidation. After distributing amounts equal to the minimum quarterly distribution to common and subordinated unitholders and distributing amounts to eliminate any arrearages to common unitholders, the Partnership s general partner is entitled to incentive distributions if the amount the Partnership distributes 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	$0.300	98%	2%
First Target Distribution	up to $0.345	98%	2%
Second Target Distribution	above $0.345 up to $0.375	85%	15%
Third Target distribution	above $0.375 up to $0.450	75%	25%
Thereafter	above $0.45	50%	50%

The table above assumes that the Partnership s general partner maintains its 2% general partner interest, that there are no arrearages on common units and the general partner continues to own the IDRs. The maximum distribution sharing percentage of 50.0% includes distributions paid to the general partner on its 2.0% general partner interest and does not include any distributions that the general partner may receive on limited partner units that it owns or may acquire.

5. NET INCOME PER LIMITED PARTNER UNIT

The Partnership s net income attributable to the initial assets for periods including and subsequent to May 14, 2008 and its net income attributable to the Powder River assets for periods including and subsequent to December 19, 2008 is allocated to the general partner and the limited partners, including any subordinated unitholders, in accordance with their respective ownership percentages, and giving effect to incentive distributions allocable to the general partner.
The Partnership s net income allocable to the limited partners is allocated between the common and subordinated unitholders by applying the provisions of the partnership agreement that govern actual cash distributions as if all earnings for the period had been distributed. Accordingly, if current net income allocable to the limited partners is less than the minimum quarterly distribution, or if cumulative net income allocable to the limited partners since May 14, 2008 is less than the cumulative minimum quarterly distributions, more income is allocated to the common unitholders than the subordinated unitholders for that quarterly period.
Basic and diluted net income per limited partner unit is calculated by dividing limited partners interest in net income by the weighted average number of limited partner units outstanding during the period. However, because the initial public offering was completed on May 14, 2008, the number of units issued in connection with the initial public offering, including shares issued in connection with the partial exercise of the underwriters over-allotment option, is utilized for purposes of calculating basic earnings per unit for the 2008 periods that include May 14, 2008 as if the shares were outstanding from May 14, 2008. The common units and general partner units issued in connection with the Powder River acquisition are included on a weighted-average basis for the 13 days they were outstanding during 2008. Diluted net income per unit reflects the potential dilution of common-equivalent units that could occur if units granted under the LTIP were settled in common units.

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The following table illustrates the Partnership s calculation of net income per unit for common and subordinated partner units (in thousands, except per-unit information):

	Twelve Months Ended December 31, 2008	
Net income	$	65,276
Less Predecessor interest in net income[1]		23,173
Less general partner interest in net income		842
Limited partner interest in net income	$	41,261
Net income allocable to common units	$	20,841
Net income allocable to subordinated units		20,420
Limited partner interest in net income	$	41,261
Net income per limited partner unit basic		
Common units	$	0.78
Subordinated units	$	0.77
Total	$	0.78
Net income per limited partner unit diluted		
Common units	$	0.78
Subordinated units	$	0.77
Total	$	0.77
Weighted average limited partner units outstanding basic		
Common units		26,680
Subordinated units		26,536
Total		53,216
Weighted average limited partner units outstanding diluted		
Common units		26,710
Subordinated units		26,536
Total		53,246

(1) Includes net income attributable to the initial assets up to May 14,

2008 and net income attributable to the Powder River assets up to December 19, 2008.

6. TRANSACTIONS WITH AFFILIATES

Affiliate transactions

The Partnership provides natural gas gathering, compression, treating and transportation services to Anadarko, which results in affiliate transactions. A portion of the Partnership s expenditures were paid by or to Anadarko, which also resulted in affiliate transactions. In addition, contributions to and distributions from Fort Union were paid or received by the Parent, resulting in affiliate transactions. Prior to May 14, 2008 with respect to the initial assets and prior to December 19, 2008 with respect to the Powder River assets, balances arising from affiliate transactions were net-settled on a non-cash basis by way of an adjustment to parent net equity. Anadarko charged the Partnership interest at a variable rate (6.04% for November 2008) on outstanding affiliate balances owed by the Partnership to Anadarko for the periods these balances remained outstanding. Affiliate-based interest expense on intercompany balances was not charged subsequent to May 14, 2008 with respect to the initial assets or subsequent to December 19, 2008 with respect to the Powder River assets as the outstanding affiliate balances were entirely settled through an adjustment to parent equity in connection with the initial public offering and the Powder River acquisition. The Partnership will incur interest expense on its $175.0 million term loan payable to Anadarko. See *Term Loan Agreement with Anadarko* below.

Notes to consolidated financial statements of Western Gas Partners, LP

Contribution of AGC, PGT, MIGC and the Powder River assets to the Partnership

Concurrent with the closing of the initial public offering in May 2008, Anadarko contributed the assets and liabilities of AGC, PGT and MIGC to the Partnership in exchange for a 2.0% general partner interest, 100% of the IDRs, 5,725,431 common units and 26,536,306 subordinated units. In connection with the Powder River acquisition in December 2008, Anadarko contributed the Powder River assets to the Partnership for consideration consisting of $175.0 million cash, 2,556,891 common units and 52,181 general partner units. See *Note 1 Description of Business and Basis of Presentation.*

Note receivable from Anadarko

Concurrent with the closing of the initial public offering, the Partnership loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%. Interest on the note is payable quarterly.

Term Loan Agreement with Anadarko

Concurrent with the closing of the Powder River acquisition, the Partnership entered into a five-year, $175.0 million term loan agreement with Anadarko which calls for interest at a fixed rate of 4.0% for the first two years and a floating rate of interest at three-month LIBOR plus 150 basis points for the final three years. The Partnership has the option to repay the amount due in whole or in part commencing upon the second anniversary of the term loan agreement. The provisions of the term loan agreement are non-recourse to our general partner and our limited partners and contain customary events of default, including (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due; (ii) certain events of bankruptcy or insolvency with respect to the Partnership; or (iii) a change of control.

Commodity Price Swap Agreements

The Partnership entered into commodity price swap agreements with Anadarko in December 2008 to mitigate exposure to commodity price volatility that would otherwise be present as a result of the Partnership s acquisition of the Hilight and Newcastle Systems. Specifically, the commodity price swap agreements fix the margin the Partnership will realize under percent-of-proceeds contracts applicable to natural gas processing activities at the Hilight and Newcastle Systems. In this regard, the Partnership s notional volumes for each of the swap agreements are not specifically defined; instead, the commodity price swap agreements apply to volumes equal in amount to the Partnership s share of actual volumes processed at the Hilight and Newcastle Systems. Because the notional volumes are not fixed, the commodity price swap agreements do not satisfy the definition of a derivative financial instrument. The Partnership will recognize gains and losses on the commodity price swap agreements in the period in which the associated revenues are recognized.

Below is a summary of the fixed prices on the Partnership s commodity price swap agreements outstanding as of December 31, 2008. The commodity price swap arrangements are for two years and the Partnership can extend the agreements, at its option, annually for three additional years.

	Year Ended December 31, 2009	2010
	(per barrel)	
Natural Gasoline	$55.60	$63.20
Condensate	$62.27	$70.72
Propane	$35.56	$40.63
Butane	$42.24	$48.15
	(per MMBtu)	
Natural Gas	$ 4.85	$ 5.61

Cash management

Anadarko operates a cash management system whereby excess cash from most of its subsidiaries, held in separate bank accounts, is swept to a centralized account. Prior to May 14, 2008 with respect to the initial assets and prior to

December 19, 2008 with respect to the Powder River assets, sales and purchases related to third-party transactions were received or paid in cash by Anadarko within the centralized cash management system and were settled with the Partnership through an

Notes to consolidated financial statements of Western Gas Partners, LP

adjustment to parent net equity. Subsequent to May 14, 2008 with respect to the initial assets and subsequent to December 19, 2008 with respect to the Powder River assets, the Partnership cash-settles transactions directly with third parties and with Anadarko affiliates.

Credit facilities

In March 2008, Anadarko entered into a five-year $1.3 billion credit facility under which the Partnership may borrow up to $100.0 million. Concurrent with the closing of the initial public offering, the Partnership entered into a two-year $30.0 million working capital facility with Anadarko as the lender. See *Note 11 Debt* for more information on these credit facilities.

Omnibus agreement

Concurrent with the closing of the initial public offering, the Partnership entered into an omnibus agreement with the general partner and Anadarko that addresses the following:

- Anadarko s obligation to indemnify the Partnership for certain liabilities and the Partnership s obligation to indemnify Anadarko for certain liabilities;

- the Partnership s obligation to reimburse Anadarko for all expenses incurred or payments made on the Partnership s behalf in conjunction with Anadarko s provision of general and administrative services to the Partnership, including salary and benefits of the general partner s executive management and other Anadarko personnel and general and administrative expenses which are attributable to the Partnership s status as a separate publicly traded entity;

- the Partnership s obligation to reimburse Anadarko for all insurance coverage expenses it incurs or payments it makes with respect to the Partnership s assets; and

- the Partnership s obligation to reimburse Anadarko for the Partnership s allocable portion of commitment fees that Anadarko incurs under its $1.3 billion credit facility.

Pursuant to the omnibus agreement, Anadarko performs centralized corporate functions for the Partnership, such as legal, accounting, treasury, cash management, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, tax, marketing and midstream administration. The Partnership s reimbursement to Anadarko for certain general and administrative expenses allocated to the Partnership is capped at $6.65 million annually through December 31, 2009, subject to adjustment to reflect changes in the Consumer Price Index and to reflect expansions of the Partnership s operations through the acquisition or construction of new assets or businesses. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses allocated to or incurred by the Partnership as a result of being a publicly traded partnership. The consolidated financial statements of the Partnership include costs allocated by Anadarko pursuant to the omnibus agreement for periods including and subsequent to May 14, 2008.

Services and secondment agreement

Concurrent with the closing of the initial public offering, the general partner and Anadarko entered into a services and secondment agreement pursuant to which specified employees of Anadarko are seconded to the general partner to provide operating, routine maintenance and other services with respect to the assets owned and operated by the Partnership under the direction, supervision and control of the general partner. Pursuant to the services and secondment agreement, the Partnership will reimburse Anadarko for services provided by the seconded employees. The initial term of the services and secondment agreement is 10 years and the term will automatically extend for additional twelve-month periods unless either party provides 180 days written notice otherwise before the applicable twelve-month period expires. The consolidated financial statements of the Partnership include costs allocated by Anadarko pursuant to the services and secondment agreement for periods including and subsequent to May 14, 2008 with respect to the initial assets and periods including and subsequent to December 1, 2008 with respect to the Powder River assets.

Notes to consolidated financial statements of Western Gas Partners, LP

Tax sharing agreement

Concurrent with the closing of the initial public offering, the Partnership and Anadarko entered into a tax sharing agreement pursuant to which the Partnership reimburses Anadarko for the Partnership s share of Texas margin tax borne by Anadarko as a result of the Partnership s results being included in a combined or consolidated tax return filed by Anadarko with respect to periods subsequent to May 14, 2008. Anadarko may use its tax attributes to cause its combined or consolidated group, of which the Partnership may be a member for this purpose, to owe no tax. However, the Partnership is nevertheless required to reimburse Anadarko for the tax the Partnership would have owed had the attributes not been available or used for the Partnership s benefit, irrespective of whether Anadarko pays taxes for the period.

Allocation of costs

The consolidated financial statements of the Partnership include costs allocated by Anadarko in the form of a management services fee for periods prior to May 14, 2008 with respect to the initial assets and prior to December 1, 2008 with respect to the Powder River assets. General, administrative and management costs were allocated to the Partnership based on its proportionate share of Anadarko s assets and revenues. Management believes these allocation methodologies are reasonable.

The employees supporting the Partnership s operations are employees of Anadarko. Anadarko charges the Partnership its allocated share of personnel costs, including costs associated with Anadarko s non-contributory defined pension and postretirement plans and defined contribution savings plan, through the management services fee or pursuant to the omnibus agreement and services and secondment agreement described above.

Equity-based compensation

Pursuant to SFAS 123(R), grants made under equity-based compensation plans result in equity-based compensation expense which is determined, in part, by reference to the fair value of equity compensation as of the date of the relevant equity grant.

Long-term incentive plan

The general partner awarded 30,304 phantom units valued at $16.50 each to the general partner s independent directors in May 2008. These phantom units were granted under the LTIP and will vest in May 2009. Total compensation expense attributable to the phantom units granted under the LTIP is expensed entirely by the Partnership and, during the year ended December 31, 2008, was approximately $323,000. The Partnership expects to recognize approximately $177,000 of additional compensation expense over the next five months related to the phantom units granted under the LTIP.

Equity incentive plan and Anadarko incentive plans

In April 2008, the general partner awarded to its executive officers an aggregate of 50,000 UVRs, UARs and DERs under its Incentive Plan. Equity-based compensation expense for grants made pursuant to the Incentive Plan as well as the Anadarko Incentive Plans is included in general and administrative expenses as a component of the compensation expense allocated to the Partnership by Anadarko and reflected in the Partnership s financial statements for the year ended December 31, 2008. The Partnership s general and administrative expense for the year ended December 31, 2008 included approximately $1.9 million of equity-based compensation expense for grants made pursuant to the Incentive Plan and Anadarko Incentive Plans. No such expense was included in the Partnership s general and administrative expense for the years ended December 31, 2007 or 2006. These expenses are allocated to the Partnership by Anadarko as a component of compensation expense for the executive officers of the Partnership s general partner and employees who provide services to the Partnership pursuant to the omnibus agreement and the services and secondment agreement. The above amount excludes compensation expense associated with the LTIP.

Summary of affiliate transactions

The following table summarizes affiliate transactions (in thousands). Affiliate expenses do not bear a direct relationship to affiliate revenues and third-party expenses do not bear a direct relationship to third-party revenues. Accordingly, the Partnership s affiliate expenses are not those expenses necessary for generating affiliate revenues. Operating expenses include all amounts accrued for or paid to affiliates for the operation of the Partnership s systems, whether in providing

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services to affiliates or to third parties, including field labor, measurement and analysis and other disbursements. Changes in parent net equity, including affiliate transactions and other payments made to or received from Anadarko, were settled through an adjustment to parent net equity prior to May 14, 2008 with respect to the initial assets and prior to December 19, 2008 with respect to the Powder River assets. Thereafter, affiliate transactions are cash-settled.

	Year Ended December 31,		
	2008	**2007**	**2006**
	(in thousands)		
Affiliate transactions			
Revenues affiliates	$ (271,643)	$ (245,302)	$ (121,635)
Operating expenses affiliates	52,548	38,867	19,492
Interest income affiliates	(11,883)		
Interest expense affiliates	2,692	7,805	9,574
Loan receivable from Anadarko	$ 260,000	$	$
Loan payable to Anadarko	175,000		
Reimbursement to parent from offering proceeds	45,161		
Distribution to unitholders affiliates	15,279		

	As of December 31,	
	2008	**2007**
Receivables from and payables to affiliates		
Accounts receivable	$ 3,235	$
Natural gas imbalance receivables	1,422	
Note receivable from Anadarko	260,000	
Natural gas imbalance payable	1,198	
Accrued liabilities	153	
Note payable to Anadarko	175,000	
Parent net investment		392,140

7. INCOME TAXES

The components of the Partnership s income tax expense are as follows:

	Year Ended December 31,		
	2008	**2007**	**2006**
	(in thousands)		
Current income tax expense			
Federal income tax expense	$ 11,758	$ 8,411	$ 2,101
State income tax expense	395	313	
Total current income tax expense	$ 12,153	$ 8,724	$ 2,101
Deferred income tax expense			
Federal income tax expense	609	11,345	4,650
State income tax expense (benefit)	1,015	(529)	(1,424)

Total deferred income tax expense	1,624	10,816	3,226
Total income tax expense	$ 13,777	$ 19,540	$ 5,327

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Total income taxes differed from the amounts computed by applying the statutory income tax rate to income before income taxes. The sources of these differences are as follows:

	Year Ended December 31, 2008	2007	2006
	(in thousands)		
Income before income taxes	$ 79,053	$ 56,198	$ 18,028
Statutory tax rate	35%	35%	35%
Tax computed at statutory rate	27,669	19,669	6,310
Adjustments resulting from:			
Partnership income not subject to federal taxes	(15,011)		
Federal taxes at lower graduated rate			(62)
State income taxes, net of federal tax benefit	1,115	268	178
Texas law change		(408)	(1,104)
Other	4	11	5
Income tax expense	$ 13,777	$ 19,540	$ 5,327
Effective tax rate	17%	35%	30%

The tax effects of temporary differences that give rise to significant portions of deferred tax assets and liabilities are as follows:

	Year Ended December 31, 2008	2007
	(in thousands)	
Net operating loss and credit carryforwards	$ 14	$ 2,916
Net current deferred income tax assets	14	2,916
Depreciable property	(1,652)	(126,184)
Equity investment		(3,083)
Net operating loss and credit carryforwards	599	
Net long-term deferred income tax liabilities	(1,053)	(129,267)
Total net deferred income tax liabilities	$ (1,039)	$ (126,351)

Credit carryforwards, which are available for utilization on future income tax returns, are as follows:

	December 31,	Statutory

	2008 (in thousands)	Expiration
State credit	$ 613	2027

8. CONCENTRATION OF CREDIT RISK

Anadarko was the only customer from whom revenues exceeded 10% of the Partnership s consolidated revenues for the years ended December 31, 2008, 2007 and 2006. The percentage of revenues from Anadarko and the Partnership s other customers are as follows:

	Year Ended December 31,		
Customer	2008	2007	2006
Anadarko	86%	92%	94%
Other	14%	8%	6%
Total	100%	100%	100%

Notes to consolidated financial statements of Western Gas Partners, LP

9. PROPERTY, PLANT AND EQUIPMENT

A summary of the historical cost of the Partnership s property, plant and equipment is as follows:

	Estimated useful life	December 31, 2008	December 31, 2007
		(dollars in thousands)	
Land	n/a	$ 354	$ 354
Gathering systems	15 to 25 years	585,304	532,312
Pipeline and equipment	30 to 34.5 years	85,598	84,651
Assets under construction	n/a	7,690	22,904
Other	3 to 25 years	1,645	902
Total property, plant and equipment		680,591	641,123
Accumulated depreciation		162,776	129,348
Total net property, plant and equipment		$ 517,815	$ 511,775

The cost of property classified as Assets under construction is excluded from capitalized costs being depreciated. This amount represents property elements that are works-in-progress and not yet suitable to be placed into productive service as of the balance sheet date.

10. ASSET RETIREMENT OBLIGATIONS

The following table provides a summary of changes in asset retirement obligations. Revisions in estimates for the periods presented relate primarily to revisions of current cost estimates, inflation rates and/or discount rates.

	Year Ended December 31, 2008	2007	2006
	(in thousands)		
Carrying amount of asset retirement obligations at beginning of period	$ 10,534	$ 9,968	$ 3,491
Additions	1,327	102	1,338
Accretion expense	775	604	367
Revisions in estimates	(3,543)	(140)	4,772
Carrying amount of asset retirement obligations at end of period	$ 9,093	$ 10,534	$ 9,968

11. DEBT

In December 2008, the Partnership entered into a five-year $175.0 million term loan agreement with Anadarko in order to finance the Powder River acquisition. See *Note 6 Transactions with Affiliates*.

In March 2008, Anadarko entered into a five-year $1.3 billion credit facility under which the Partnership may borrow up to $100.0 million to the extent that sufficient amounts remain unborrowed by Anadarko and its subsidiaries. As of December 31 2008, the full $100.0 million was available for borrowing by the Partnership. Interest on borrowings under the credit facility is calculated based on the election by the borrower of either: (i) a floating rate equal to the federal funds effective rate plus 0.50% or (ii) a periodic fixed rate equal to LIBOR plus an applicable margin. The applicable margin, which was 0.44% at December 31, 2008, and the commitment fees on the facility are based on Anadarko s senior unsecured long-term debt rating. Pursuant to the omnibus agreement, as a co-borrower under Anadarko s credit facility, the Partnership is required to reimburse Anadarko for its allocable portion of commitment fees (currently 0.11% of the Partnership s committed and available borrowing capacity, including the Partnership s outstanding balances) that Anadarko incurs under its credit facility, or up to $110,000 annually. Under the credit facility, the Partnership and Anadarko are required to comply with certain covenants, including a financial covenant that requires Anadarko to maintain a debt-to-capitalization ratio of 65% or less. As of December 31, 2008, Anadarko was in compliance with all covenants. Should the Partnership or Anadarko fail to comply with any covenant in Anadarko s credit facility, the Partnership may not be permitted to borrow under the credit facility. Anadarko is a guarantor of all borrowings under the credit facility, including the Partnership s borrowings. The Partnership is not a guarantor of Anadarko s borrowings under the credit facility.

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Concurrent with the closing of the initial public offering, the Partnership entered into a two-year $30.0 million working capital facility with Anadarko as the lender. At December 31, 2008, no borrowings were outstanding under the working capital facility. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility will bear interest at the same rate as would apply to borrowings under the Anadarko credit facility described above. Pursuant to the omnibus agreement, the Partnership will pay a commitment fee of 0.11% annually to Anadarko on the unused portion of the working capital facility, or up to $33,000 annually. The Partnership is required to reduce all borrowings under the working capital facility to zero for a period of at least 15 consecutive days at least once during each of the twelve-month periods prior to the maturity date of the facility.

In December 2007, Anadarko and an entity organized by a group of unrelated investors formed Trinity Associates, LLC (Trinity). Trinity extended a $2.2 billion loan to WGR Asset Holding Company, LLC (WGR Asset Holdings), a subsidiary of Anadarko. Western Gas Wyoming, L.L.C. (WG Wyoming), which owns the 14.81% membership interest in Fort Union and that was contributed to the Partnership in connection with its Powder River acquisition on December 19, 2008, was a subsidiary of WGR Asset Holdings. On February 16, 2008, the Partnership and WG Wyoming, along with other Anadarko subsidiaries, became joint and several guarantors of the $2.2 billion loan. The principal amount due from WGR Asset Holdings to Trinity under the loan was $1.8 billion as of December 31, 2008. Pursuant to the loan agreement, all guarantees with respect to the Partnership s assets were automatically released immediately prior to the closing of the initial public offering. Similarly, WG Wyoming s obligations related to this guarantee were released on December 19, 2008 in connection with the closing of the Powder River acquisition.

12. SEGMENT INFORMATION

The Partnership s operations are organized into a single business segment, the assets of which consist of natural gas gathering and processing systems, treating facilities, a pipeline and related plant and equipment. To assess the operating results of the Partnership s segment, management uses Adjusted EBITDA, which it defines as net income (loss) plus distributions from equity investee, interest expense, income tax expense and depreciation, less income from equity investee, interest income, income tax benefit and other income (expense).

Adjusted EBITDA is a supplemental financial measure that management and external users of the Partnership s consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

- the Partnership s operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;
- the ability of the Partnership s assets to generate cash flow to make distributions; and
- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

Management believes that the presentation of Adjusted EBITDA provides information useful in assessing the Partnership s financial condition and results of operations and that Adjusted EBITDA is a widely accepted financial indicator of a company s ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA, as defined by the Partnership, may not be comparable to similarly titled measures used by other companies. Therefore, the Partnership s consolidated Adjusted EBITDA should be considered in conjunction with net income and other performance measures, such as operating income or cash flow from operating activities.

Notes to consolidated financial statements of Western Gas Partners, LP

Below is a reconciliation of Adjusted EBITDA to net income.

	Year Ended December 31,		
	2008	**2007**	**2006**
		(in thousands)	
Reconciliation of Adjusted EBITDA to net income			
Adjusted EBITDA	$ 112,474	$ 91,830	$ 47,239
Less:			
Distributions from equity investee	5,128	1,348	741
Interest expense, net affiliates	1,259	7,805	9,574
Interest expense from note affiliate	253		
Income tax expense	13,777	19,540	5,327
Depreciation and impairment	42,365	30,481	20,230
Other expense		15	26
Add:			
Equity income, net	4,736	4,017	1,360
Interest income from note affiliate	10,703		
Other income	145		
Net Income	$ 65,276	$ 36,658	$ 12,701

13. COMMITMENTS AND CONTINGENCIES

Environmental

The Partnership is subject to federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. Management believes there are no such matters that will have a material adverse effect on the Partnership s results of operations, cash flows or financial position.

Litigation and legal proceedings

From time to time, the Partnership is involved in legal, tax, regulatory and other proceedings in various forums regarding performance, contracts and other matters that arise in the ordinary course of business. Management is not aware of any such proceeding for which a final disposition could have a material adverse effect on the Partnership s results of operations, cash flows or financial position.

Lease commitments

Anadarko, on behalf of the Partnership, has entered into leases for compression equipment. During 2007, Anadarko restructured certain third-party lease commitments, resulting in a new lease and the purchase of previously leased equipment. Compression equipment purchased by Anadarko was contributed to the Partnership. In October 2008, Anadarko modified certain lease arrangements including leased compression equipment used exclusively by the Partnership. As a result of the lease modifications, Anadarko became the owner of the compression equipment, effectively terminating the lease. Pursuant to the Contribution, Conveyance and Assumption Agreement signed in connection with the initial public offering, Anadarko contributed the compression equipment to the Partnership. The carrying value of the compression equipment was approximately $14.1 million.

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During 2008, Anadarko entered into a new third-party lease for office space used by the Partnership. The office lease will expire in January 2010 and there is no purchase option at the termination of the lease. The amounts in the table below represent existing contractual lease obligations for the office lease as of December 31, 2008 that may be assigned or otherwise charged to the Partnership (in thousands).

	Minimum rental payments
2009	$ 149
2010	9
Total	$ 158

Rent expense associated with the compressor leases and the office lease was approximately $1.2 million, $1.2 million and $3.0 million for the years ended December 31, 2008, 2007 and 2006, respectively.

14. QUARTERLY FINANCIAL DATA (unaudited)

The following table presents a summary of the Partnership s operating results by quarter for the years ended December 31, 2008 and 2007. Financial information for 2007 and the first three quarters of 2008 has been revised to include results attributable to the Powder River assets. See *Note 3 Powder River Acquisition.*

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per unit amounts)			
2008				
Revenues	$82,034	$89,996	$82,206	$57,412
Operating income	$25,985	$17,047	$ 8,198	$18,487
Net income	$15,762	$15,976	$13,425	$20,113
Net income per limited partner unit[1]	n/a	$ 0.15	$ 0.32	$ 0.30
2007				
Revenues	$61,761	$63,779	$65,489	$70,464
Operating income	$15,763	$16,294	$12,908	$19,053
Net income	$ 8,837	$ 8,123	$ 7,798	$11,900

(1) Net income per limited partner unit is calculated as net income attributable to the limited partners, which excludes income attributable to the initial assets up to May 14,

2008 and excludes income attributable to the Powder River assets up to December 19, 2008. See *Note 5 Net Income Per Limited Partner Unit*.

15. SUBSEQUENT EVENT

On January 29, 2009, the board of directors of the Partnership s general partner declared a cash distribution to the Partnership s unitholders of $0.30 per unit, or $17.0 million in aggregate. The cash distribution was paid on February 13, 2009 to unitholders of record at the close of business on January 30, 2009.